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Asian Development Bank

Background Study on CCUS Readiness in Power, Iron and Steel, Cement and Petroleum Sectors

Contents

Contents i
PREFACE ix
ACKNOWLEDGMENTS x
ABBREVIATIONS xi
EXECUTIVE SUMMARY xiii
Chapter 1 General Introduction to Carbon Capture, Utilization and Storage Readiness 1
1.1 Background to the Study 1
1.2 Trends for the Power and Industrial Sectors in Asian Countries 1
1.2.1 Power Sector 3
1.2.2 Iron and Steel Sector 4
1.2.3 Cement Sector 4
1.2.4 Petroleum Sector 5
1.3 Importance of Carbon Capture, Utilization and Storage-Readiness 8
1.4 Cost Barriers to Carbon Capture, Utilization and Storage Implementation 10
1.5 Definitions of Carbon Capture, Utilization and Storage Readiness 10
1.6 Rationale for Delaying Carbon Capture, Utilization and Storage Implementation 13
1.7 Economic and Regulatory Changes Needed to Trigger Carbon Capture, Utilization and Storage Implementation 13
1.7.1 Carbon Tax 14
1.7.2 Carbon Trading 14
1.7.3 Emission Limiting Legislation 15
Chapter 2 Overview of Carbon Dioxide Capture Technologies 16
2.1 Carbon Dioxide Capture Technologies 17
2.1.1 Post-combustion Capture of Carbon Dioxide 17
Amine-based Absorption of Carbon Dioxide 17
Adsorption of Carbon Dioxide 19
Membrane-based Separation of CO_2 19
2.1.2 Pre-combustion Capture of Carbon Dioxide 20
2.1.3 Oxyfuel Combustion Systems 21
Allam Cycle 22
Chemical Looping Combustion 22
2.2 Carbon Dioxide Utilization Technologies 24
2.2.1 Ethanol from Carbon Dioxide 24
2.2.2 Mineralization of Carbon Dioxide 24
2.3 Technologies and Infrastructure Enabling the Deployment Carbon Dioxide Capture, Utilization and Storage 25

2.3.1 Common Carbon Dioxide Infrastructure 25
2.3.2 Combined Stripping of Sulfur Oxides and Carbon Dioxide 25
2.3.3 Use of Fuel Cell to Strip Carbon Dioxide 25
Chapter 3 Transport, Storage and Use of Carbon Dioxide 27
3.1 Introduction to Carbon Dioxide Transport 27
3.2 Carbon Dioxide Properties and Impact on Transport 27
3.2.1 Impurities in the Carbon Dioxide Stream 29
3.2.2 Effect of Water on Carbon Dioxide Transport 29
3.2.3. Health, Safety and Environment Considerations 29
3.3 Routing 30
3.3.1 Pipeline Route 30
3.3.2 Shipping Route 30
3.3.3 Possibility for Reuse of Infrastructure 30
3.3.4 Multisource and Multisink CO_2 Transport Infrastructure 31
3.4 Economic Considerations for Carbon Dioxide Transport Options 32
3.4.1 Pipeline Costs 32
3.4.2 Ship Transport Costs 32
3.4.3 Dependence of Transport Option on Flowrates and Distances 35
3.4.4 Estimation of Expenses for Transport-Readiness 36
3.4.5 Examples of Costed CCUS Transport Studies 36
3.4.6 Options for Financing Transport in CCUS Readiness 37
3.5 Timeline for Carbon Capture, Utilization and Storage-readiness in Carbon Dioxide Transport. 38
3.6 Carbon Dioxide Storage 39
3.6.1 Storage Options for Carbon Dioxide in Asia 41
3.6.2 Carbon Dioxide Storage-readiness 42
Chapter 4 Power Generation Sector 46
4.1 Introduction to the Power Generation Sector 46
4.2 Description of the Value Chain in the Power Generation Sector 46
4.3 Carbon Dioxide Emissions from the Power Generation Sector 47
4.4 Carbon Dioxide Capture Technologies in the Power Generation Sector 48
4.4.1 Space requirement in power plant layout 53
4.4.2 Flue Gas Cleaning Requirement 53
4.4.3 Steam requirement 54
4.4.4 Electricity Requirement 54
4.4.5 Summary of Capture-Readiness Requirements 55
4.5 Capture-ready Prospects in the Power Generation Sector 56
4.6 Economic Considerations for Carbon Dioxide Capture in the Power Generation Sector 56
4.7 Timeline for Carbon Capture, Utilization and Storage-readiness in the Power Generation Sector 57
Chapter 5 Carbon Dioxide Capture Opportunities in the Iron and Steel Sector 58

5.1 Introduction to the Steel Sector 58
5.2 Description of the Value Chain in the Steel Sector 59
Table 5.1 Iron and Steel Values and Data Sources for United Kingdom 60
5.3 Carbon Dioxide Sources in the Steel Sector 61
5.3.1 Blast Furnace/Basic Oxygen Furnace Steel Process 61
5.3.2 Electric Arc Furnace Route 63
5.3.3 Direct Reduced Iron Electric Arc Furnace Route 63
5.4 Carbon Dioxide Capture Technologies in the Steel Sector 65
5.5 Capture-ready Prospects in the Steel Sector 66
5.6 Economic Considerations for Carbon Dioxide Capture in the Steel Sector 66
5.7 Timeline for Carbon Capture, Utilization and Storage-readiness in the Steel Sector 69
Chapter 6 Cement Sector 72
6.1 Introduction to the Cement Sector 72
6.2 Description of the Value Chain in the Cement Sector 73
6.2.1 The Reference Cement Clinker Plant 73
6.3 Carbon Dioxide Sources in the Cement Sector 74
6.4 Carbon Dioxide Capture Technologies for the Cement Sector 75
6.4.1 Post-Combustion Capture 76
6.4.2 Oxy-fuel Combustion 76
6.4.3 LEILAC Direct Separation Technology 77
6.4.4 Calcium Looping 77
6.5 Capture-Ready Prospects in the Cement Sector 78
6.6 Economics of CO_2 Capture in the Cement Sector 78
6.7 Timeline for Carbon Capture, Utilization and Storage-Readiness in the Cement Sector 79
Chapter 7 Petroleum Sector 80
7.1 Introduction to the Petroleum Sector 80
7.2 Description of the Value Chain in the Petroleum Sector 80
7.2.1 Oil Refining 80
7.2.2 Natural Gas Processing 82
7.3 Carbon Dioxide Sources in the Petroleum Sector 82
7.3.1 Carbon Dioxide Sources from Oil Refining 82
7.3.2 Carbon Dioxide from Natural Gas Processing 83
7.4 Carbon Dioxide Capture Technologies for the Petroleum Sector 83
7.4.1 Post-Combustion Capture 83
7.4.2 Oxyfuel Combustion 83
7.4.3 Carbon Dioxide By-Product Processing 84
7.5 Capture-Ready Prospects in the Petroleum Sector 84
7.5.1 Post-Combustion Carbon Dioxide Capture from a Petroleum Refinery 84

7.5.2 Carbon Dioxide from Hydrogen Production 85
7.5.3 Carbon Dioxide from Natural Gas Processing 85
7.5.4 Multiple Technologies at the Same Site 85
7.5.5 Novel Technology Application 85
7.6 Economic Considerations for Carbon Dioxide Capture in the Petroleum Sector 86
7.6.1 Carbon Dioxide from Hydrogen Production and Natural Gas Processing 86
7.6.2 Carbon Dioxide from Refinery Post-Combustion Capture 86
7.7 Timeline for CCUS Readiness in the Petroleum Sector 86
Chapter 8 Financing Carbon Capture Utilization and Storage Readiness 88
8.1 Traditional Sources of Financing 88
8.1.1 Sponsor Equity 88
8.1.2 Tax Equity 88
8.1.3 Debt Capital 88
8.1.4 Corporate Finance 88
8.1.5 Project Finance 89
8.2.1 Why CCUS Readiness Financing Remains a Challenge 90
8.3 Pre-Investments for CCUS Readiness 91
8.4 CCUS Readiness Financing Mechanisms 94
8.4.1 Capital Grants 94
8.4.2 Mandates and Standards 94
8.4.3 Tax Credits 94
8.4.4 Dedicated CCUS Fund 95
8.4.5 Premium Feed-in-Tariff 95
8.4.6 Concessional Finance 95
8.4.7 Loan Guarantees 95
8.5 Other Innovative CCUS Readiness Financing Mechanisms 96
8.5.1 Capture-Ready Options Trading 96
8.5.2 Yieldcos 96
Chapter 9 Carbon Capture, Utilization and Storage Readiness in Industries—Next Steps 97
Appendix A Case Study—Power: Bibiyana Natural Gas Combined Cycle Power Plant, Hobiganj, Bangladesh 99
A.1 Introduction 100
A.2 Factors to be Considered in CCUS Readiness for Power Plants 102
A.3 Bibiyana 341 MW Natural Gas Combined Cycle Power Plant Carbon Capture, Utilization and Storage Readiness 104
A.3.1 Composition of Turbine Exhaust Gas 104
A.3.2 General Layout 105
A.3.3 Heat Integration/Availability of Steam 107
A.3.4 Water Treatment and Cooling 108
A.3.5 Extra Power 109
A.4 CCUS Cost vs CCUS Readiness Cost 110

A.5 Summarizing the Assessment of Capture-Readiness Criteria for the plant 111
A.6 Conclusions 112
Appendix B Case Study—Cement: Citeureup, Indonesia 113
B.1 Introduction 113
B.2 Post-combustion Carbon Capture 113
B.3 Cost Calculations 115
B.4 Energy for the Carbon Capture Installation 116
B.5 Storage 117
Appendix C Financial Vehicles and Activities 119
C.1 Funding Vehicles for Carbon Capture Utilization and Storage Projects 119
C.2 Financing activities for CCUS readiness framework 121
References 125

BOXES

Box 1. Operating CCUS power plants worldwide
Box 3.1 Existing experience in CO_2 transport
Box 3.2 Examples of CCUS Readiness projects
Box 3.3 Project of Common Interest
Box 3.4 Other storage options potentially relevant for Asian countries
Box 3.5 Utilisation of CO_2 as a means to accelerate CCS implementation
Box 3.6 Scope for CO_2/EOR in China
Box 4.1 Boundary Dam CCUS project
Box 4.2 The Shand Power CCS readiness study
Box 4.3 Petra Nova CCUS plant
Box 4.4 Kemper County IGCC power plant with CCUS
Box 7. Example of CO_2 utilisation from an oil refining operation

TABLES

Table 1.1 Energy Technology Perspectives Model Results for Asian Regions in 2060 8
Table 1.2 Proposed International Definition of CCS-Ready by Global CCS Institute 12
Table 1.3 Carbon Tax Rates in Some European Countries..... 14
Table 3.1 Cost Components for Ship Transport..... 33
Table 3.2 Pros and Cons of Transportation Options..... 34
Table 3.3 Estimated Geological Storage Capacity for Countries in Asia..... 42
Table 4.1 Flue Gas Properties of Typical Modern Power Plant Units..... 47
Table 4.2 Selected Countries' Emission Standards for Coal-fired Power Plants 54
Table 4.3 Capture-Ready Benchmarks for CO_2 Post-Combustion Capture Plant Design 55
Table 5.1 Iron and Steel Values and Data Sources for United Kingdom..... 60
Table 5.2 Carbon Dioxide Emission Points from Modelled Integrated Blast Furnace and Basic Oxygen Furnace Steel Plants..... 62
Table 5.3 Carbon Dioxide Emissions and Stream Factors for Flue gases from Blast Furnace/Basic Oxygen Furnace Process 63
Table 5.4 Carbon Dioxide Sources and Conditions for Electric Arc Furnace and Direct Reduced Iron Processes 64
Table 5.5 Key Parameters of Various Carbon Dioxide Capture Options for Blast Furnace and COREX . 67
Table 5.6 Carbon Dioxide Emission with and without Carbon Dioxide Capture 68
Table 5.7 Capital and Operating Expenses for Steel Mills without and with Carbon Dioxide Capture .. 68
Table 5.8 Status of Carbon Dioxide Removal Technologies in Iron and Steel Industries 69
Table 6.1 Pros and Cons of Each Carbon Dioxide Capture Technology..... **Error! Bookmark not defined.**
Table 6.2 CAPEX and OPEX Estimates for Cement Plant CO_2 Capture Plans 78
Table 7.1 Carbon Dioxide Emission Sources at a Typical Refinery Complex 81
Table 8.1 Comparison of Corporate Finance versus Project Finance 89
Table 8.2 Pre-Investments Required to Make Facilities Capture-Ready 92
Table 8.3 Capital Cost Breakdown for Pulverized Coal Reference Plant and Amine Scrubbing Option . 93
Table A.1 Summit Bibiyana Power Plant..... 100
Table A.2 Performance of GE's 9 FA Gas Turbine 100
Table A.3 Gas Turbine Exhaust Gas Composition 105

Table A.4 Continuous Emission Monitoring System Average Monthly Report from Heat Recovery Steam Generator (July 2018) 105
Table A.5 Steam and Gas Parameters of Heat Recovery Steam Generator 107
Table A.6 Rough Estimation of Parameters for the Natural Gas Combined Cycle Plant Under Study . 109
Table A.7 Outcomes Summary 111
Table B.1 Flue Gas Properties from Cement Kiln Lines in Citeureup Plant 114
Table B.2 Cost for carbon capture installation for production line P5 116
Table B.3 Thermal Energy from ..... Cooler Gas 117
Table C.4 CCUS Funds and Programs. 119
Table C.5 Activities and Enablers of CCUS Readiness Financing 121

FIGURES

Figure 1.1 Distribution of Global Carbon Dioxide Emissions in 2017 2
Figure 1.2 Sectoral Distribution of Carbon Dioxide Emissions in 2010 2
Figure 1.3 Power Sector Carbon Dioxide Emissions in 2018 3
Figure 1.4 World's Cement Production in 2017 5
Figure 1.5 Global Oil Demand by Sector 6
Figure 1.6 Projected World Liquids Demand 7
Figure 1.7 Projected Refining Capacities 7
Figure 1.8 CCUS required in China, India, and ASEAN Countries 9
Figure 1.9 Carbon Trading Prices in Different Markets 15
Figure 2.1 Technology Options for Carbon Dioxide Capture 16
Figure 2.2 Basic Amine Scrubbing CO2-capture Process Flow Diagram 18
Figure 2.3 Membrane Technology and Research PolarCap Process 20
Figure 2.4 Process Diagram of Pre-combustion CO_2 Capture and Compression for an Integrated Gasification Combined Cycle Power Plant 21
Figure 2.5 Oxyfuel Combustion Process Scheme 22
Figure 2.6 Allam Cycle Basic Diagram 23
Figure 2.7 Chemical Looping Combustion Diagram 23
Figure 2.8 Waste Gas-to-Ethanol Process 24
Figure 2.9 Sure Source Powerplant Carbon Capture Concept 26
Figure 3.1 CAPEX for CO_2 Transport by Ship in Europe 33
Figure 3.2 OPEX for CO_2 Transport by Ship in Europe 34
Figure 3.3 Illustrative Figure for Choosing the Most Economical Solution between Ship and Offshore Pipeline 35
Figure 3.4 CO_2 Storage Capacity Pyramid 40
Figure 5.1 Indexed Global Energy Consumption per Tonne of Crude Steel Production 59
Figure 5.2 Iron and Steel Value Chain 60
Figure 5.3 Typical Integrated Steel Mill Emissions and Carbon Balance 62
Figure 5.4 Potential Technologies to Reduce Carbon Dioxide Emissions from Blast Furnace 71
Figure 6.1 Value Chain of Cement Manufacture 73
Figure 6.2 Cement Production Process 74

Figure 6.3 Distribution of Carbon Dioxide Emissions Over the Main Processes in the Value Chain ... 75
Figure A.1 Bibiyana Natural Gas Combined Cycle Power Plant ... 99
Figure A.2 Bibiyana Power Plant Overview ... 101
Figure A.3 Visitors with Plant Engineers and Managers ... 102
Figure A.4 Simple Block Diagram of Combined Cycle Plant with Flue Gas Recirculation Post Combustion Capture ... 103
Figure A.5 Photo of the Power Plant ... 106
Figure A.6 Flue Gas Entrance to the Stack ... 106
Figure A.7 Turbine House ... 108
Figure A.8 High-Pressure Bypass ... 108
Figure A.10 Cooling Towers ... 109
Figure B.1 Preheater tower of the largest clinker production line (P14) at Citeureurup. ... 113
Figure B.2 Post-combustion carbon capture for cement plant flue gas ... 114
Figure B.3 Available area next to P5 production line which could be used for a carbon capture installation 116

PREFACE

The International Energy Agency reported a 1.7% increase in global energy-related carbon dioxide (CO_2) emissions increased in 2018, continuing an upward trend in CO_2 emissions growth since 2017 driven by increases in oil and gas consumption which more than offsets decline in coal consumption and rise in the use of renewables. The Global Carbon Project estimates that CO_2 emissions in 2019 will rise again, although at a slower rate than previous years due to declining coal consumption in the United States and Europe, and slower growth in coal consumption in China and India.

Asia, as it meets its energy requirement for its rapid development, contributes about 48% to the global energy-related CO_2 emissions. Primary energy demand in Asia and the Pacific region is expected to increase by about 24% by 2030. Despite the rapid increase in renewable energy supply, trends suggest that this increase in demand will still translate into increased consumption of fossil fuels and CO_2 emissions in the region.

While experiencing rapid growth and development, Asia and the Pacific remains one of the regions that are most vulnerable to climate change. It faces the risk of losing its development gains to climate change impacts if mitigation and adaptation actions are not put in place. This context highlights, the urgency to constrain CO_2 emissions to limit global temperature rise to well below 2 degrees Celsius, and to strive for 1.5 degrees Celsius.

Carbon capture utilization and storage (CCUS) is identified among technologies and practices that can help meet climate targets. However, there are only two operational large-scale CCUS power projects that are able to capture CO_2, and much is still to be achieved in the development and deployment of CCUS. The Asian Development Bank (ADB)—committed to achieving a prosperous, inclusive, resilient, and sustainable Asia and the Pacific while sustaining its efforts to eradicate extreme poverty—shares this view and regards CCUS as one of the means that will help the region smoothly transition to a low-carbon economy. ADB, since 2008, has been providing technical assistance to remove institutional, technical, and economic barriers to CCUS deployment in its developing member countries; including Bangladesh, India, Indonesia, People's Republic of China, and Vietnam. ADB has helped create CCUS centres of excellence, supported feasibility studies and pilot projects, built CCUS awareness through workshops and knowledge products, and fostered collaboration on CCUS with regional and international partners.

This report, *Background Study on CCUS Readiness in Power, Steel, Cement, and Petroleum Sectors,* aims to help prepare industries for eventual decarbonization with CCUS to ensure a smoother transition to a low-carbon era. The paper presents some of the existing and upcoming CCUS technologies, assesses the potential for capture-, transport-, and storage-readiness of major CO_2-emitting sectors. It also investigates the financing requirements and mechanisms, as well as policy drivers and recommendations, to advance CCUS readiness.

It is hoped that the assessment and case studies presented in this publication will help industrial sector stakeholders and policymakers of developing member countries increase their awareness and knowledge about CCUS and CCUS readiness, and develop CCUS readiness plans with the view that CCUS is an important tool in the toolbox of measures to meet climate targets and transition to a low-carbon development path.

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ABBREVIATIONS

2DS	2°C Scenario
ADB	Asian Development Bank
aMDEA	activated methyl diethanolamine
Ar	argon
B2DS	beyond 2 degrees scenario
BF	blast furnace
BFG	blast furnace gas
BOF	basic oxygen furnace
$CaCO_3$	calcium carbonate (limestone)
CaO	calcium oxide (lime)
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCUS	carbon capture, utilization and storage
CEF	Connecting Europe Facility
CHP	combined heat and power
CLC	chemical-looping combustion
CO	carbon monoxide
CO_2	carbon dioxide
COG	coke oven gas
CS	crude steel
DRI	direct reduced iron
EAF	electric arc furnace
EC	European Commission
EGR	enhanced gas recovery
EOR	enhance oil recovery
ETS	emissions trading scheme
EU	European Union
FCC	fluid catalytic crackers
FCF	free cash flows
FEED	front-end engineering design
FIT	feed-in tariff
GCCSI	Global Carbon Capture and Storage Institute
Gt	gigatonnes (10^9 tonnes)
$GtCO_2$	gigatonnes of CO_2
GW	gigawatts
H_2	hydrogen
H_2S	hydrogen sulphide
HBD	heat balance data
HRSG	heat recovery steam generator
HSE	health, safety and environment
IBRD	International Bank for Reconstruction and Development
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D programme
IGCC	integrated gasification combined cycle

INDC	Intended Nationally Determined Contribution
IPCC	Intergovernmental Panel on Climate Change
JSPL	Jindal Steel & Power Ltd
LNG	liquefied natural gas (methane)
LPG	liquefied petroleum gas (propane/butane)
kWh	kilowatt-hour (unit of electricity)
LEILAC	Low Emissions Intensity Lime and Cement
MEA	monoethanolamine
mg/Nm^3	milligrams per normal cubic metre
MPa	megapascal (~10 atmospheres pressure)
Mt	megatonnes (10^{12} grams)
Mtpa	million tonnes per annum
MW	megawatt (electric power capacity)
MWh	megawatt-hour (electricity unit)
N_2	nitrogen gas
NG	natural Gas
NGCC	natural Gas Combined Cycle
NOx	oxides of nitrogen (NO, N_2O, NO_2)
O_2	oxygen gas
OECD	Organisation for Economic Co-operation and Development
OPC	ordinary Portland cement
OPEX	operating expenditure
PC	pulverised combustion (of coal)
PCI	Projects of Common Interest
ppm	parts per million by volume
PRC	People's Republic of China
PSA	pressure swing adsorption
RGGI	Regional Greenhouse Gas Initiative
RTS	Reference Technology Scenario
RUPTL	Rencana Umum Penyediaan Tenaga Listrik (Electricity Supply Business Plan in Indonesia)
SCR	selective catalytic reduction
SO_2	sulphur dioxide
SO_x	sulphur oxide
TA	technical assistance
TRL	technology readiness level
TWh	terawatt-hour
ULCOS	Ultra-Low CO_2 Steelmaking
UK	United Kingdom
UNIDO	United Nations Industrial Development Organisation
USA	United States of America
ZEP	Zero Emissions Programme

EXECUTIVE SUMMARY

The Asian Development Bank (ADB) has been promoting Carbon Capture Utilization and Storage (CCUS) as one of the vital mitigation tools to limit global temperature rise. As Asia develops new industries to meet its developmental needs, there is a scope to establish new steel mills, cement factories, petrochemical complexes and power plants. These industries are likely sources of new emissions; but, at the same time, also offer an opportunity to make them CCUS ready, leading to an early emission capture possibility. This background document provides policymakers and industry veterans preliminary information to design their projects to be 'CCUS ready'.

Chapter 1 sets the tone of the document and gives an overview of the global emission profile. It helps in understanding the importance of steel, cement, power and petroleum sectors with respect to their emission and future growth. The chapter explains the concept of 'CCUS Readiness' and finally, it gives an overview of the financial and regulatory aspects of CCUS.

Chapter 2 begins with the classification of the capture technologies and then goes on to explain the technical aspects of the following CO_2 capture technologies:

a. Amine based absorption of CO_2
b. Adsorption of CO_2
c. Membrane-based separation of CO_2
d. Precombustion capture of CO_2
e. Oxyfuel combustion systems.

The chapter prepares the reader for new technologies and trends in CCUS. It also explains the reader why a specific aspect has to be introduced in design so that the plant is CCUS ready.

Chapter 3 is dedicated to the transportation aspects of CO_2. It explains methodologies of CO_2 transport through pipeline, rail, road and shipping. The chapter describes properties of CO_2 which have to be maintained while transporting to the site and injecting in the reservoir. The chapter identifies factors that influence the selection of a mode of transportation, choice of route of transportation and economics of CO_2 transportation. Chapter 3 also touches upon aspects associated with CO_2 storage.

Chapter 4 is devoted to CCUS readiness in the power sector. It describes the properties of flue gases from coal- and natural gas-fired power projects. Next, it describes two power plant-based CO_2 capture projects—Boundary Dam project and Petronova project. The power sector chapter describes specific CCUS requirements in terms of land, flue gas preparedness, steam requirement and electricity requirement. Finally, the economics of CCUS readiness in the power sector is discussed in this chapter.

Chapter 5 has given a background on CCUS readiness in the iron and steel sector. The value chain of the sector is described in terms of sources of CO_2. It indicates CO_2 capture potential in terms of electric arc furnaces and direct reduced iron route. It is recognized that captive power plant has almost 40 per cent emission in steel making process and hence, maybe one of the top priorities in a quest for CCUS readiness. Capture ready plant can be developed to capture 60% to 80% CO_2. Hot blast gas can contribute to emission of the steel sector; and, hence should be an area of concentration in the steel sector.

Chapter 6 has reviewed CCUS readiness for the cement sector. It has indicated that the calcination process yields 440 kg of CO_2 for every tonne of limestone processed. The most important factors are 50% in calcination and about 35% in fuel and energy. Post-combustion technology is found to be the most suitable under the circumstances. However, Low Emissions Intensity Lime and Cement (LEILAC), oxyfuel

and calcium looping are recognized as technologies which may play a bigger role in capturing CO_2 from the cement sector. The chapter has compared various cement technologies based on their costs.

Chapter 7 is dedicated to CCUS readiness for the petroleum sector. It has indicated sources of CO_2 in a petroleum refining sector and described the contribution of CO_2 by different processes. Combustion processes contribute about 30 to 60% of the total CO_2 volume of flue gas with a concentration of about 10 to 13%. Thus, this is an important but, lean source of CO_2. On the other hand, hydrogen production contributes 5 to 20% of CO_2 generation but has almost 99% concentration of CO_2. Thus, hydrogen production may be the lowest hanging fruit in case of refinery operation. An important lesson is that in refinery operations, separation of the sources based on CO_2 concentration may help in cost-effective CO_2 capture.

Chapter 8 is on the financing aspects of CCUS readiness. Financing of CCUS readiness is rather typical because CCUS readiness is not emission reduction. Since CO_2 avoidance can take place only at a later date, carbon financing cannot be resorted to in this case. Considering this situation, the chapter explores tools like capital grants, mandates and standards, tax credits, dedicated CCUS funds, and premium feed to fund CCUS readiness.

Chapter 9 is a forward-looking chapter where next steps on CCUS readiness are discussed. Some of the important observations include a common set of CCUS regulations to avoid duplication, implementation of common CO_2 transportation and storage infrastructure, and exploring newer ways to finance CCUS readiness.

Finally, the document has presented two case studies where an existing combined-cycle gas turbine-based power plant and an existing cement plant are reviewed for their suitability for capturing CO_2. The conclusion of the study is that it is much better to anticipate requirements for the capture plant of CO_2 at the design stage than to think about it when the plant is already in place.

It may be noted that some of pre-requisite for CO_2 capture technologies (such as reduction of SOx/NOx) are requirements for the local air pollution prevention as well. Hence, in normal circumstances, the pollution control equipment will be part of the manufacturing plant, whether CCS readiness is a prerequisite or not. In such cases, all the expenses attributed to SOx/NOx treatment should be considered for local air pollution. However, the pollution control measures are not followed in spite of legal stipulation and hence, when a plant is considering CCS or CCS readiness, all the costs are attributed to CCS readiness. It will be useful for the promoters of CCS to recognize such anomalies so that CCS costs are not inflated.

Some of the newer technologies are actually combining the SOx/NOx stripping with the CO_2 stripping which can make a difference in cost of CO_2 capture.

Chapter 1 General Introduction to Carbon Capture, Utilization and Storage Readiness

1.1 Background to the Study

The Asian Development Bank (ADB), under its Strategy 2030, expands its vision to achieve a prosperous, inclusive, resilient, and sustainable Asia and the Pacific while sustaining its efforts to eradicate extreme poverty. Aligning its aspirations, ADB's support focuses on several operational priorities, including *tackling climate change, building climate and disaster resilience, and enhancing environmental sustainability* (ADB 2018).

As part of its activities to tackle climate change, ADB is involved in addressing key barriers to large-scale carbon capture, utilization and storage (CCUS) demonstration, feasibility studies, environmental and social impact assessments, and monitoring of CCUS (ADB 2013). ADB has provided technical assistance (TA) amounting to $38M toward strengthening and effectively implementing CCUS since the approval of Safeguard Policy Statement in 2009 (ADB 2016).

Specifically, *TA 8714: Promoting Carbon Capture and Storage in the People's Republic of China and Indonesia* aims to create a stronger strategic architecture for accelerating and scaling up CCUS development and deployment in the People's Republic of China (PRC), Indonesia and other ADB developing member countries in Asia (ADB 2014).

CCUS is identified as a major technology intervention by ADB and as a long-term plan it has worked on this document to prepare a road to implement this technology through 'CCUS readiness.'

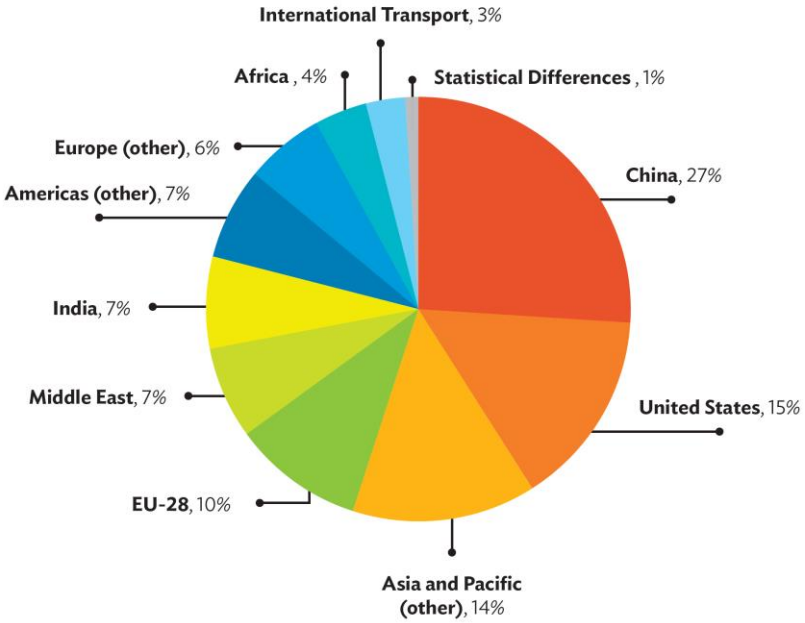
1.2 Trends for the Power and Industrial Sectors in Asian Countries

Asia contributed about half of the 36.15 $GtCO_2$[1] of global carbon dioxide (CO_2) emissions in 2017. As shown in Figure 1.1, the People's Republic of China (PRC) and India accounted for 27% and 7% of the global CO_2 emissions in 2017.

The energy, industrial, and residential and commercial sectors represent around two-thirds of the CO_2 emissions worldwide, as shown in Figure 1.2. In this section, the current and projected CO_2 emissions for the three largest industrial sectors, power, cement and steel, are detailed for Asian countries. CO_2 emissions from the Asian oil refining and petrochemical sectors are not adequately defined for the purposes of comparative assessment.

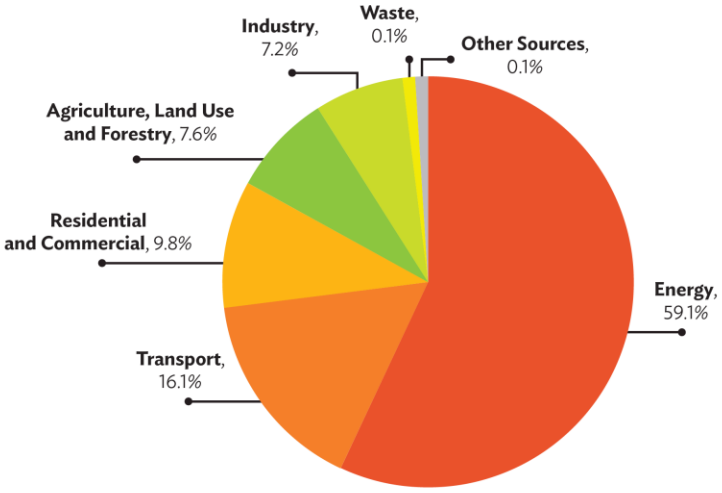
[1] 1 Gigatonne of CO ($GtCO_2$) = 1,000,000,000 metric tonnes of CO_2

Figure 1.1 Distribution of Global Carbon Dioxide Emissions in 2017



EU = European Union.
Note: "Statistical differences" notes the discrepancy between estimated global emissions and the sum of all national and international transport emissions.
Source: Le Quéré et al. (2018). Global Carbon Project. Carbon Dioxide Information Analysis Centre Retrieved from https://ourworldindata.org/co2-and-other-greenhouse-gas-emissions#annual-co2-emissions.

Figure 1.2 Sectoral Distribution of Carbon Dioxide Emissions in 2010



CO_2 = carbon dioxide
Note: in million tonnes CO_2
Source: Adapted from Food and Agriculture Organization of the United Nations (FAO). http://www.fao.org/faostat/en/?#data/. Retrieved from https://ourworldindata.org/co2-and-other-greenhouse-gas-emissions#annual-co2-emissions.

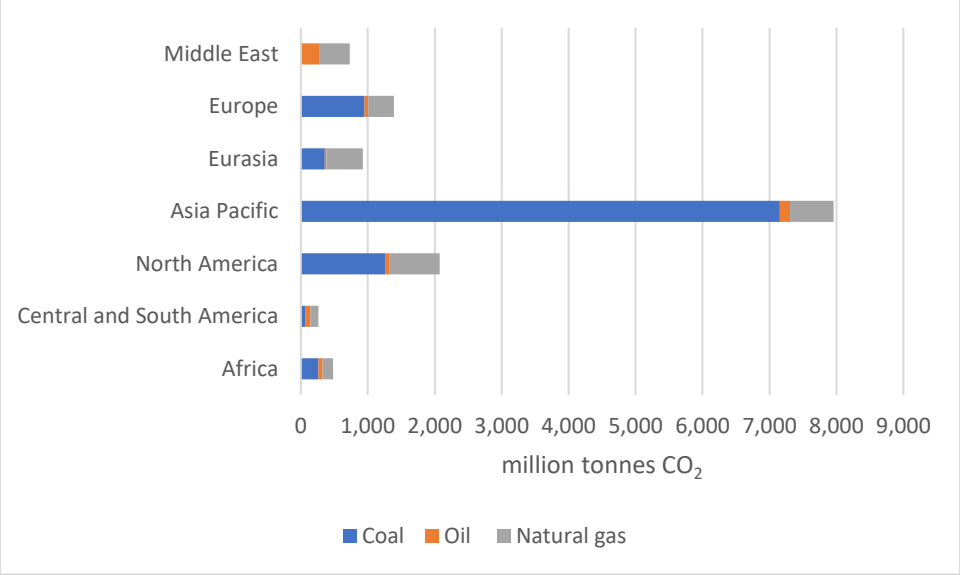
1.2.1 Power Sector

In 2018, the power sector contributed about 42% of the total 33,243 million tonnes of global energy-related CO_2 emissions. As shown in Figure 1.3, the Asia Pacific power sector produced 58% of the total power sector emission (International Energy Agency [IEA] 2019a). In the same year, the Asia Pacific region generated 15,450 TWh of electricity with more than half coming from coal power plants.

China accounts for more than half of the world's coal consumption, providing more than two-thirds of China's primary energy. China's power generation sector consumes more than half of that coal, which provides about 80% of China's electricity. The Chinese power sector currently emits over 4 Gt CO_2 ($GtCO_2$) per year[2], 95% from coal-fired power generation. The Chinese power sector CO_2 emissions are projected to increase to 5 or 6 Gt/y in the 2030s under low growth and high growth scenarios respectively, before starting to reduce after 2040 (Guangdong CCS Centre for Excellence [GDCCUSC] 2018). That projection is based on efficiency improvements, fuel switching and structural changes in the energy industry, but does not include CCUS.

The Indonesian 10-year Electricity Supply Business Plan (RUPTL) projects that electricity consumption in Indonesia will increase by 6.42% per year from 245 TWh in 2019 to 433 TWh in 2028. To meet this demand, additional 56,395 MW of generation capacity is planned for 2019–2028 (Perusahaan Listrik Negara [PLN] 2019). About 27,000 MW of additional generating capacity is from coal-fired power plants (Brown and Hamdi 2019). Emissions from Indonesia's coal plants is projected to peak to about 315 $MtCO_2$ by 2035 (Climate Analytics 2019). By 2025, Indonesia's energy mix is expected to be 54.6% coal, 3% new and renewable energy, 22% gas, and 0.4% diesel (PLN 2019).

Figure 1.3 Power Sector Carbon Dioxide Emissions in 2018



CO_2 = carbon dioxide.
Source: Adapted from International Energy Agency (2019). *World Energy Outlook 2019*.

[2] Chinese power sector currently emits 40% of total Chinese CO_2 emissions shown in Figure 1.1

1.2.2 Iron and Steel Sector

Closely following the cement industry in terms of direct CO_2 emissions, the iron and steel industry emitted 2.1 Gt of CO_2 in 2017 (IEA 2019b). World steel production reached 1,628 million tons of crude steel (CS) in 2016 (World Steel Association 2017). The Asian region is responsible for 69%, of which China is responsible for 49.7 % of the world total. Chinese steel production declined from 822 million tons in 2014 to 804 million tons in 2015. Although production rose in 2016, it is expected to decline in 2017. Part of this is due to the Chinese government's decision to reduce overcapacity and increase utilization rate, chiefly through the closing of intermediate frequency furnaces, leading to a reduction in the capacity by 50 million tons in 2017 (DBS 2017).

India is targeting high growth in steel manufacturing with the government targeting production of 300 million tons by 2030 (EY 2014). As part of this plan, India is forecast to grow from the fourth largest steel producer currently to the second largest by 2019. Viet Nam, Thailand, and Indonesia rank second, third and fourth respectively in net steel imports. All of these countries are targeting a reduction in net imports and increased domestic production.

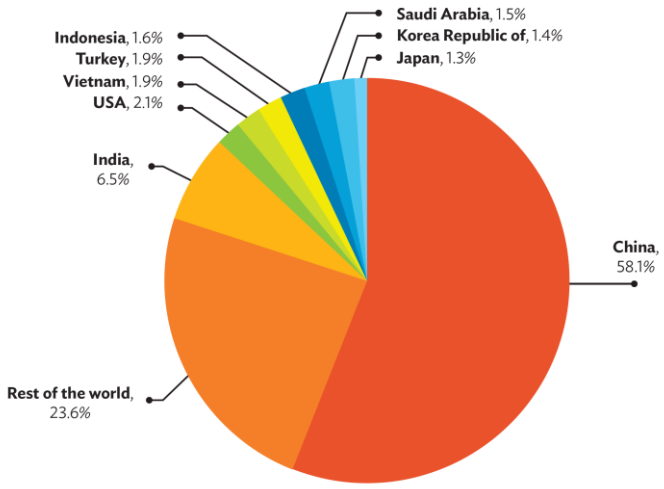
Across Asia, most steel is produced by converting iron ore to iron in a blast furnace (BF) then converting the iron to steel in a basic oxygen furnace (BOF). Worldwide the BF-BOF method is used for 66% of all steel production and 94% of Chinese steel production (Birat 2010). The other main method for producing steel is the electric arc furnaces (EAF) fed with scrap steel or iron produced by direct reduction (DR) of iron ore. EAF accounts for around 25% and 6% of world steel production respectively. BF-BOF processes is more suited to large scale production of steel from iron ore to satisfy large markets. EAF processes are more favoured for smaller steel mills where the feed is, predominantly scrap metal.

1.2.3 Cement Sector

As one of the largest industrial emitters of CO_2, the cement industry emits 27% of the global anthropogenic industrial emissions. The worldwide cement sector produces annually 4.1 Gt of cement, resulting in 3.9 $GtCO_2$ emissions (Leeson, et al 2017). In terms of direct emissions, the cement sector is the largest emitter of CO_2 with 2.2 $GtCO_2$ emissions in 2017 (IEA 2019b).

Asia contributes considerably to the world's cement production with China and India as the first- and second-largest cement producing countries in the world, with a respective 2.4 Gt and 0.28 Gt of annual cement production i.e. 58.5% and 6.8%, as shown in Figure 1.2. Due to China's rapid industrialization and urbanization, the cement industry has showed an exponential growth from 1980, when cement production was 79.9 Mt, by an average of 10% growth per year to 2,400 Mt in 2017. The development of cement production in China up to 2050 will, of course, be heavily influenced by population growth, economic stability and other factors and is therefore hard to predict. The expectation is that the Chinese cement industry had its peak in 2015 and will decrease to 800–1400 Mt by 2050 (Xu et al 2014). China still uses a lot of old-fashioned vertical kilns (~20%) instead of more energy-efficient dry rotary kilns that are equipped with preheaters and pre-calciners (Wen et al 2015).

Figure 1.4 World's Cement Production in 2017



US = United States.
Note: US includes Puerto Rico.
Source: Adapted from U.S. Geological Survey. 2018. Mineral Commodity Summaries, January 2018. p. 43. https://prd-wret.s3-us-west-2.amazonaws.com/assets/palladium/production/atoms/files/mcs-2018-cemen.pdf.

India is the second-largest cement producer in the world, with an annual production of 220 Mt producing 0.16 $GtCO_2$ emissions (IEA 2012b). The cement production per capita is one of the lowest in the world, indicating that India's cement production can grow significantly up to 2050. According to CO_2 emission projections from the International Energy Agency (IEA), CO_2 emissions in India will rise to 0.27-0.49 $GtCO_2$/y in 2050, depending on the adopted CO_2 reduction measures. To achieve 0.27 $GtCO_2$/y in 2050, India would have to lower the CO_2 emission factor to 0.35 tCO_2/t cement, compared with the value in 2010, which was 0.719 tCO_2/t cement (Wen et al 2015). Overall, India employs more modern kilns than China; most of the kilns are dry rotary kilns (Kumar 2015).

1.2.4 Petroleum Sector

Indirect greenhouse gas emissions from the extraction, processing and transportation of oil and gas supply amounted to 5,200 Mt CO_{2e}, which is almost 15% of the global energy sector emissions, in 2017. In terms of CO_2 emissions only, the oil sector produced 2,060 Mt CO_2 while the gas sector produced 810 Mt CO_2. Refining is the largest source of CO_2 for oil, while extraction and processing are the biggest sources of CO_2 for gas (IEA 2018). By 2040, the 2018 New Policies Scenario of IEA projects that CO_2 emissions from oil will reach 2,240 Mt CO_2 while the gas sector emissions will reach up to 1,330 Mt CO_2.

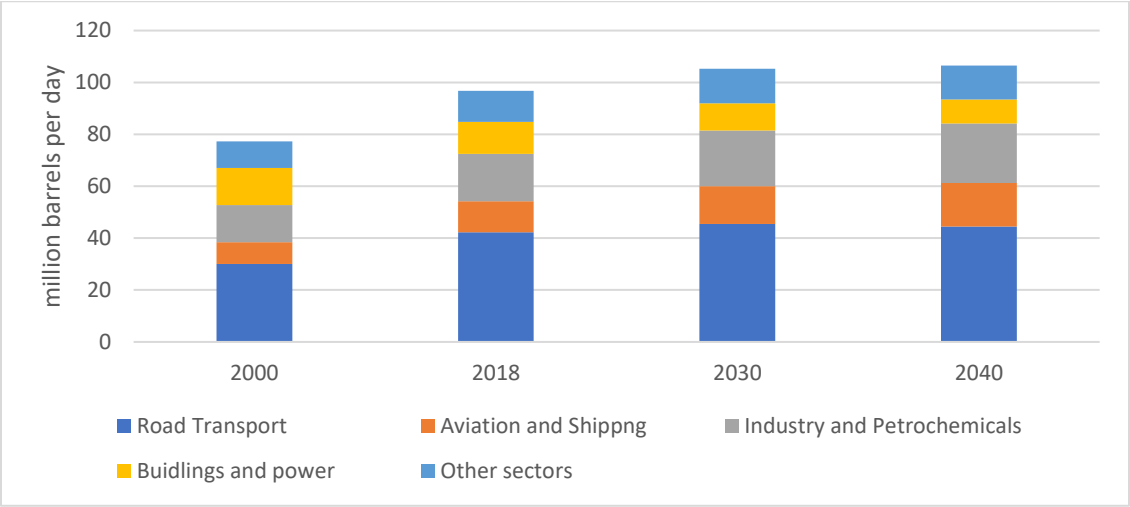
In its Stated Policies Scenario[3], IEA (2019a) estimates that global oil demand, which is largely driven by demand from petrochemicals, trucks and aviation, will continue to grow up to 106.4 million barrels per day (mb/d) by 2040. Although there is no prediction of peak oil demand, the widely introduced scheme

[3] In its World Energy Outlook 2019, the International Energy Agency renamed its New Policies Scenario as Stated Policies Scenario. The Stated Policies Scenario considers only specific policy initiatives that has been announced (IEA 2019b).

to limit diesel cars and the promotion for electric vehicles, and regulatory changes in marine shipping fuel supply result to demand changes as shown in Figure 1.5.

Global investment in a new refinery and petrochemical infrastructure has slowed down after the 2014 oil price crash. Investments for upstream oil and gas capital spending has also made its contribution to the slow growth for refinery and petrochemical sector up to 2018. Tighter regulations for reducing greenhouse gases emission and the rapid development for shale gas exploration have resulted from changes in the sources for oil supply, with more biofuels and natural gas liquefaction products increasing its contribution in the downstream market growth as shown in Figure 1.6.

Figure 1.5 Global Oil Demand by Sector

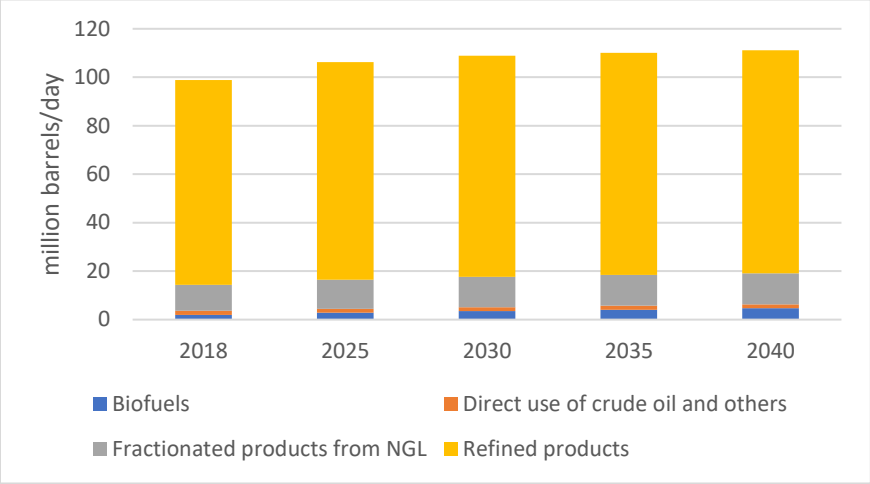


Note: Based on the International Energy Agency's Stated Policies Scenario.
Source IEA.2019. *World Energy Outlook 2019.*

Therefore, retrofitting some of the existing refining and petrochemical and prepare for the changes in the future product is necessary. More rigour regulation on greenhouse gas control has also resulted in the refining and petrochemical industries' transformation towards much leaner fuel and less polluted production process. Planning new refining and petrochemical infrastructure to prepare for the changes will significantly help to reduce the risk of carbon lock-in in the future.

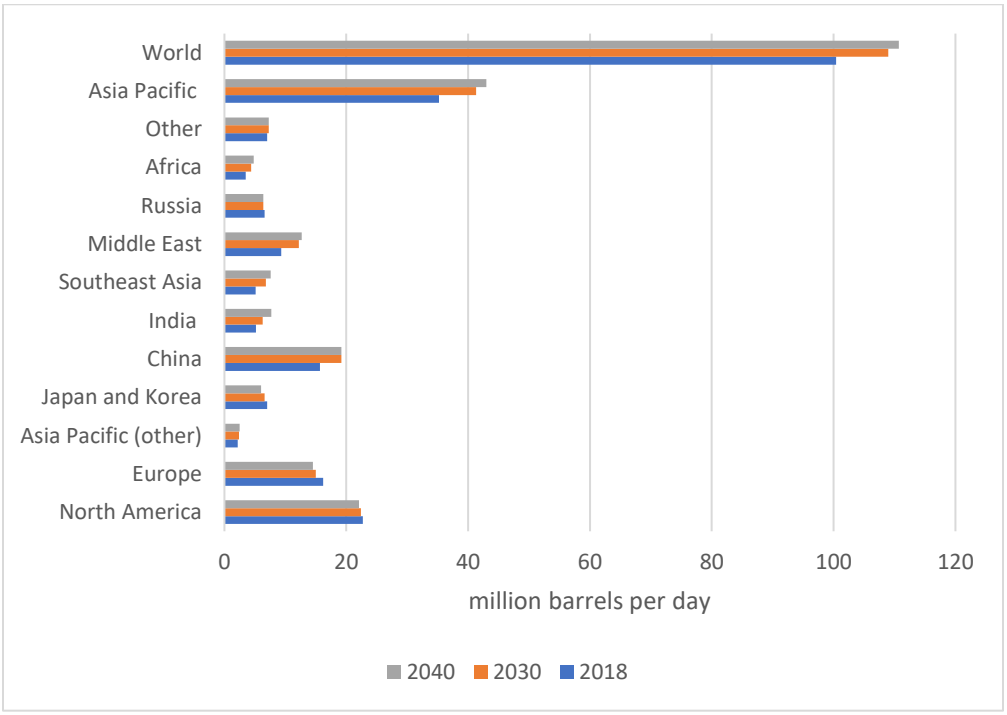
In Asia, demand for crude oil remains strong and more refinery will start construction. Figure 1.7 shows the estimated refining capacities in IEA's Stated Policies Scenario with Asia taking up more than half of the capacity additions. By 2040, additional 7.8 mb/d of refinery capacity is projected to come online (IEA 2019a). Constructing the refinery and petrochemical plants in Asia in a CCS ready way is crucial for the long-term operation of those plants.

Figure 1.6 Projected World Liquids Demand



NGL = natural gas liquids.
Notes: Others include coal-to-liquids, gas-to-liquids and additives. Based on the International Energy Agency's Stated Policies Scenario.
Source: Adapted from International Energy Agency (2019). *World Energy Outlook 2019.*

Figure 1.7 Projected Refining Capacities



Note: Based on the International Energy Agency's Stated Policies Scenario.
Source: Adapted from International Energy Agency (2019). *World Energy Outlook 2019.*

In 2018, demand for natural gas reached 3,952 bcm, accounting for over 45% of growth in the world energy demand. Based on IEA's Stated Policies Scenario, demand for natural gas is expected to grow more than four times faster than oil and reach up to 5,404 bcm. Asia Pacific natural gas demand is projected to grow by 87% from its 2018 level to 1,522 in 2040 (IEA 2019b).

1.3 Importance of Carbon Capture, Utilization and Storage-Readiness

The Paris Agreement aims to strengthen the global response to the threat of climate change by keeping the global temperature rise this century well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5°C degrees Celsius (United Nations Climate Change 2018). A new report from IPCC identifies that limiting temperature rise to 1.5°C is now imperative to avoid the worst effects of climate change and the report quantifies measures to achieve that outcome (IPCC 2018). As the urgency to address climate change becomes ever more acute in recognition of its impact on natural and human systems, political pressure is increasing on major industries to curb CO_2 emissions. Since global energy demand cannot be lowered very rapidly in the short term, then CCUS will be required to reach the Paris Agreement ambition. In the models reviewed by the IPCC, the cumulative CCUS capacity required by 2100 could be between 348 and 1,218 $GtCO_2$. (IPCC 2018). The largest CCUS scenario includes bioenergy carbon capture and storage (BECCS) to achieve negative emissions.

IEA modelled to 2060 the least-cost emission reduction and mitigation scenarios required to keep the global temperature rise to 2°C (2DS) and beyond 2°C (B2DS) compared to a reference technology scenario (RTS) considering today's commitments by regions to limit emissions and improve energy efficiency, including the Nationally Determined Contributions (NDCs) pledged under the Paris Agreement (IEA 2017). The IEA Energy Technology Perspectives model findings for the B2DS scenario are shown in Table 1.1. For reference, one $GtCO_2$ per year of CO_2 emission reduction is equivalent to 90% CO_2 capture on about 300 x 660 MWe power generation units.

Table 1.1 Energy Technology Perspectives Model Results for Asian Regions in 2060

$GtCO_2$ per year in 2060	**PRC**	**India**	**ASEAN**
Reference Technology Scenario (RTS)	8.0	6.8	3.5
Beyond 2 degrees scenario (B2DS)	0.2	0.5	0.5
Contributions to CO_2 emission reductions required to achieve B2DS			
Contribution from Power Sector	3.5	3.2	1.7
Contribution from Industry Sector	2.3	1.6	0.4
Contribution from all other sectors	2.0	1.6	1.0
Contribution by CCUS	**1.6**	**0.6**	**0.7**

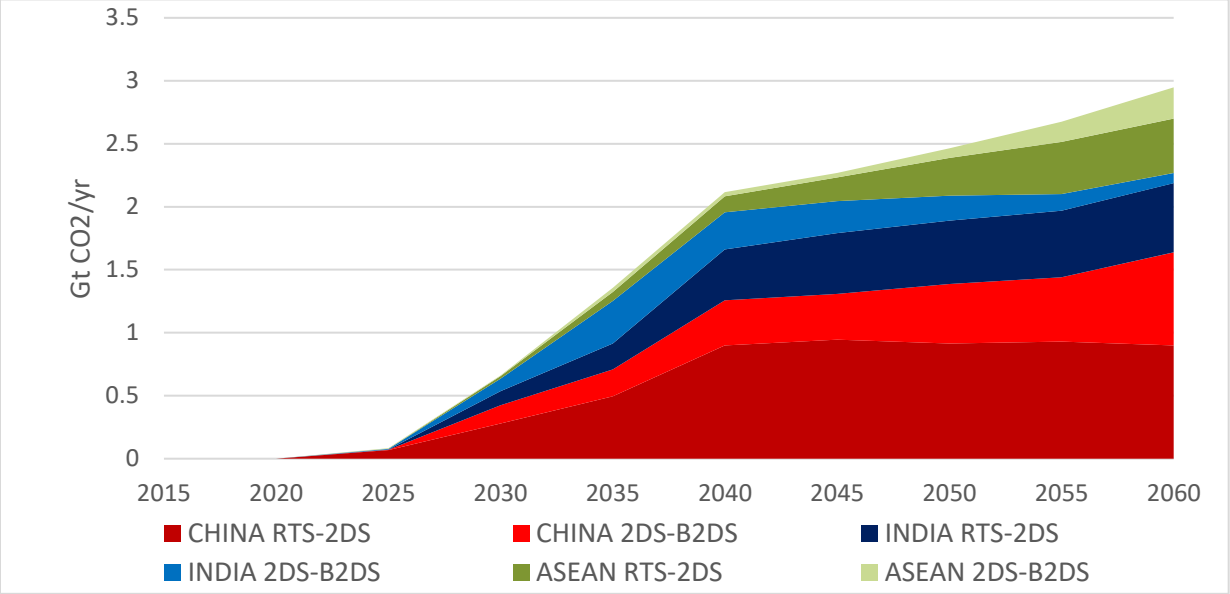
ASEAN = Association of Southeast Asian Nations, B2DS = below 2 degrees scenario, CCUS = carbon capture, utilization and storage, GtCO2 = gigatonnes carbon dioxide, PRC = People's Republic of China, RTS = reference technology scenario.
Source: International Energy Agency. 2017. *Energy Technology Perspectives*. https://www.iea.org/etp/explore/.

This IEA Energy Technology Perspectives modelling also shows the extent of CCUS that would be required, in conjunction with many other measures, to achieve the 2DS scenario and also the more challenging

B2DS scenario. The CCUS component of Energy Technology Perspectives model data are presented in Figure 1.8, which shows that for both power and industry sectors combined, the CCUS contribution to reducing CO_2 emissions from the Reference Technology Scenario (RTS) to the 2 Degrees Scenario (2DS) and also the additional CCUS contribution to reducing CO_2 emissions from the 2DS to the IEA's Below 2 Degrees Scenario (B2DS).

Figure 1.8 shows that 65 $GtCO_2$ would have to be stored by 2060 in Asia to meet the Paris objective, comprising 37 $GtCO_2$ in China, 19 $GtCO_2$ in India and 9 $GtCO_2$ in ASEAN countries.[4] It is therefore essential for the power and industry sectors in Asia to design new plants, and where possible adapt existing plants, to be ready to apply CCUS on a large scale by 2025 and to identify adequate CO_2 storage capacity. Therefore, CCUS readiness planning should begin now.

Figure 1.8 CCUS required in China, India, and ASEAN Countries



ASEAN = Association of Southeast Asian Nations, B2DS = below 2 degrees scenario, CCUS = carbon capture, utilization and storage, GtCO2 = gigatonnes carbon dioxide, IEA = International Energy Agency, RTS = reference technology scenario, 2DS = below 2 degrees scenario.
Source: Adapted from IEA (2017), Energy Technology Perspectives.

[4] Or net storage of CO_2 in the case of CO_2 utilisation schemes, such as enhanced oil recovery.

Box 1: Operating Carbon Capture and Storage Plants Worldwide

In 2018, there were 18 operating large-scale CCS projects reported by the Global Carbon Capture and Storage Institute (GCCSI).

- Two operating plants capturing CO_2 from coal-fired power generation: Boundary Dam facility in Saskatchewan, Canada and Petra Nova facility in Texas, USA. Both operating plants use post-combustion capture technology.
- Nine capturing CO_2 on natural gas processing plants,
- And seven on other industrial plants.

14 of these operating plants produce a CO_2 product for use in EOR. Two operating CCUS plants deliver CO_2 separated from natural gas to offshore Norwegian geological storage; Sleipner (operation started in 1996) and Snøhvit (operation started in 2008), driven by a high Norwegian carbon tax. The Quest project in Canada and the Illinois Industrial project in the USA are demonstrating dedicated onshore geological storage of CO_2 without EOR.

Source: Global CCS Institute (GCCSI). 2018. *The Global Status of CCS 2018.* Australia.

1.4 Cost Barriers to Carbon Capture, Utilization and Storage Implementation

In the current economic and regulatory environment, there is no adequate incentive or statutory requirement to include CO_2 capture and storage in the construction of new power plants or industrial plants, except where there is a local demand for commodity CO_2 for enhanced oil recovery (EOR). Tax incentives and low carbon fuel standards are discussed in Chapter 8.

Carbon emission trading schemes (ETS) have been established in many countries to provide market incentives for actions to reduce CO_2 emissions. With a few exceptions, the market price of traded carbon is currently much less than the cost of implementing CCUS. However, traded carbon prices are projected to increase.

If the Paris Climate Change target of limiting global temperature rise to 2°C is to be achieved, then CCUS on thermal power plants and some industrial plants will be required within the lifetime of facilities that are being designed now. Therefore, power plants and some industrial plants should be designed now ready for CO_2 capture to be retrofitted when the economic or regulatory environments change.

1.5 Definitions of Carbon Capture, Utilization and Storage Readiness

CCUS readiness of an industrial plant means that plans and capabilities are in place for implementing CCUS at some future time if the economic drivers or regulatory environment change. This definition of CCUS readiness excludes reliance on the availability of opportunities for the commercial utilization of captured CO_2 at an undetermined future time. Therefore, the term “CCS-ready” is used in this section rather than “CCUS-ready.”

The Global Carbon Capture and Storage Institute (GCCSI 2016) proposed a definition of CCS readiness. GCCSI expects that a standardized definition of a CCS-Ready plant will assist countries in developing and implementing policy frameworks to deploy CCS-ready plants if the requirements are widely accepted. The definition in Table 1.2 is a result of a series of international roundtables held by the GCCSI with CCS stakeholders. This GCCSI definition matches CCS-ready criteria of Europe's Committee for Sustainable Energy (ECE 2015) and UK Guidelines (DECC 2009). This may be considered as a strong CCS readiness definition, as may be required for the legal permitting of a proposed development to meet legislative requirements. In contrast, alternative weaker CCS readiness criteria may be considered adequate for environmental reporting and publicity purposes. For example; a weaker CCS readiness plan might include delivery of CO_2 to a port, with no definition of the subsequent storage location that the CO_2 would be transported to by ship.

This definition considers three components of CCS separately as capture-ready plant, transport-ready plant and storage-ready plant. Environmental regulations, safety and public awareness and engagement are the most important aspects, and they are included in all the three components of readiness.

Electric power plants and industrial plants with and without CCS need to be commercially viable contributors to the fleet of power plants supplying an electricity transmission grid. For CCS-ready status to be credible, a plant would need to be as efficient and economical as practicable, both before and after the retrofitting of CCS. Whilst CCS would only be implemented when a significant change in the economic and regulatory situation eventuates (e.g. a major increase in the traded carbon price), the interim host plant performance without CCS must not be compromised by the provisions for CCS readiness. This consideration eliminates some the highly-integrated CCS schemes (e.g. oxyfuel conversion or pre-combustion capture integration) from suitability for consideration in the context of CCS readiness.

The CCS-Ready plan should be based on a CCS design concept and costing that could be practically implemented when the plant is commissioned initially. The actual implementation would then occur when different legislative, financial or economic conditions; eventuate, maybe 5 or 10 years after initial commissioning.

A principal CCS-ready requirement is the allocation of space for the additional CO_2 capture equipment and the retrofitting activity. A case study in Indonesia indicates that the additional land requirement for CO_2 capture equipment is likely to be about half of the host power plant footprint (World Bank 2015). However, land requirements are case-specific.

Table 1.2 Proposed International Definition of CCS-Ready by Global CCS Institute

Capture-Ready Plant	Transport-Ready Plant	Storage-Ready Plant
A CO_2 capture-ready plant satisfies all or some of the following criteria: 1) Sited such that transport and storage of captured volumes are technically feasible; 2) Technically capable of being retrofitted for CO_2 capture using one or more reasonable choices of technology at an acceptable economic cost; 3) Adequate space allowance has been made for the future addition of CO_2 capture-related equipment, retrofit construction, and delivery to a CO_2 pipeline or other transportation systems; 4) All required environmental, safety and other approvals have been identified; 5) Public awareness and engagement activities related to potential future capture facilities have been performed; 6) Sources for equipment, materials, and services for future plant retrofit and capture operations have been identified; and 7) Capture-Readiness is maintained or improved over time, as documented in reports and records.	A CO_2 transport-ready plant satisfies all or some of the following criteria: 1) Potential transport methods are technically capable of transporting captured CO_2 from the source(s) to geologic storage-ready site(s) at an acceptable economic cost; 2) Transport routes are feasible, rights of way can be obtained, and any conflicting surface and subsurface land uses have been identified and/or resolved; 3) All required environmental, safety and other approvals for transport have been identified; 4) Public awareness and engagement activities related to potential future transportation have been performed; 5) Sources for equipment, materials, and services for future transport operations have been identified; and 6) Transport-Readiness is maintained or improved over time, as documented in reports and records.	A CO_2 storage-ready plant satisfies all or some of the following criteria: 1) One or more storage sites have been identified that are technically capable of, and commercially accessible for, geological storage of full volumes of captured CO_2 at an acceptable economic cost; 2) Adequate capacity, injectivity, and storage integrity have been shown to exist at the storage site(s); 3) Any conflicting surface and subsurface land use at the storage site(s) have been identified and/or resolved; 4) All required environmental, safety, and other approvals have been identified; 5) Public awareness and engagement activities related to potential future storage have been performed; 6) Sources for equipment, materials, and services for future injection and storage operations have been identified; and 7) Storage-Readiness is maintained or improved over time, as documented in reports and records.

CCS = carbon capture and storage, CO_2 = carbon dioxide.

Sources: Global CCS Institute. 2016. *Carbon Capture and Storage Readiness Index*. November 2016; ICF. 2010. Defining CCS-Ready: An Approach to an International Definition. Melbourne: GCCSI; Economic Commission for Europe. 2015. Status on Global Carbon Capture and Storage Readiness (CCSR) Discussion. Geneva: Economic Commission for Europe. Committee on Sustainable Energy, Expert Group on Cleaner Production of Electricity from Fossil Fuels; Department of Energy and Climate Change (UK). 2009. Carbon Capture Readiness (CCR) - A Guidance Note for Section 36 Electricity Act 1989 Consent Applications. London: UK Department of Energy and Climate Change.

1.6 Rationale for Delaying Carbon Capture, Utilization and Storage Implementation

In a competitive electricity market, immediately loading the full cost of CCUS onto a fossil fuel power plant would distort the local competitive electricity market putting the converted power plants down the power generation merit order and reducing their load factors; worsening their economics. Likewise, in a global competitive commodity market, immediately loading the full cost of CCUS onto an industrial production plant would damage its competitiveness in the global market place, causing production to shift to countries without a requirement to apply CCUS.

CCUS implementation requires regulatory and economic conditions at a global level, which may occur at some unknown future time. Therefore, it is prudent to prepare for that eventuality when a new power plant or industrial plant is built so that the risk of the new facility becoming a stranded asset is reduced.

1.7 Economic and Regulatory Changes Needed to Trigger Carbon Capture, Utilization and Storage Implementation

To achieve the extent of CCUS indicated in Figure 1.6, economic drivers or legislated regulations are necessary. The market for CO_2 as a commodity is insufficient for CCUS to achieve the scale of CO_2 emission reduction required. If the cost of emitting CO_2 to the atmosphere is greater than the net cost of CCUS (after any revenue from CO_2 sales), then there will be an economic imperative on industries to implement CCUS. In some European countries, a high carbon tax has been introduced, and as a consequence, some CCUS implementation has occurred. Carbon emissions trading has been widely introduced with the objective of minimising the impacts on CO_2 emitting industries. In general, carbon pricing has not yet reached the point at which implementation of CCUS becomes economically viable. However, In North America measures such as tax credits (45Q), carbon portfolio standards, intensity-based cap & trade (e.g. LCFS), and government procurement standards, in combination with EOR opportunities has led to commercial CCUS projects being commissioned at a time of high oil prices.

A benchmark CCUS cost has been in the order of $100 per tonne of CO_2 emission avoided for a first-of-a-kind complete CCUS process chain including transport and storage (World Bank 2015). A current study of retrofitting CO_2 capture to the Shand Power station in Canada, learning from the nearby successful operation of the Boundary Dam CCUS plant, determines that CO_2 capture could be achieved at the cost of US$45/tonne of CO_2 captured.[5]

Even when the economic drivers pass the balance point making CCUS economically viable, there may still be practical and financial reasons to delay or avoid implementing the level of CCUS required for countries to meet their Paris obligations. If so, then emission control legislation may also be required.

[5] See Box 4.3.

1.7.1 Carbon Tax

Table 1.3 lists the European countries with a 2018 carbon tax over US$25 per tonne of CO_2. The aim of the carbon taxes is to incentivize CO_2 emission reduction. In the case of Norway, a high carbon tax was introduced in the 1990s. Consequently, it became economical for Statoil (the operators of the Sleipner gas field) to reinject CO_2 separated from natural gas into deep aquifers rather than to discharge that CO_2 to the atmosphere and to pay the carbon tax. In the case of CO_2 stripping from natural gas, CCUS just involves compression and injection of CO_2, which costs less than the carbon tax rate.

Table 1.3 Carbon Tax Rates in Some European Countries

Country	2017 Carbon Tax $/tonne of CO_2	2018 Carbon Tax $/tonne of CO_2
Denmark	27	27
Finland	73	74
France	35	53
Iceland	22	34
Lichtenstein	87	97
Norway	55	61
Sweden	121	123
Switzerland	86	97

CO_2 = carbon dioxide.
Source: Source: World Bank. 2018. State and Trends of Carbon Pricing. World Bank Group.

1.7.2 Carbon Trading

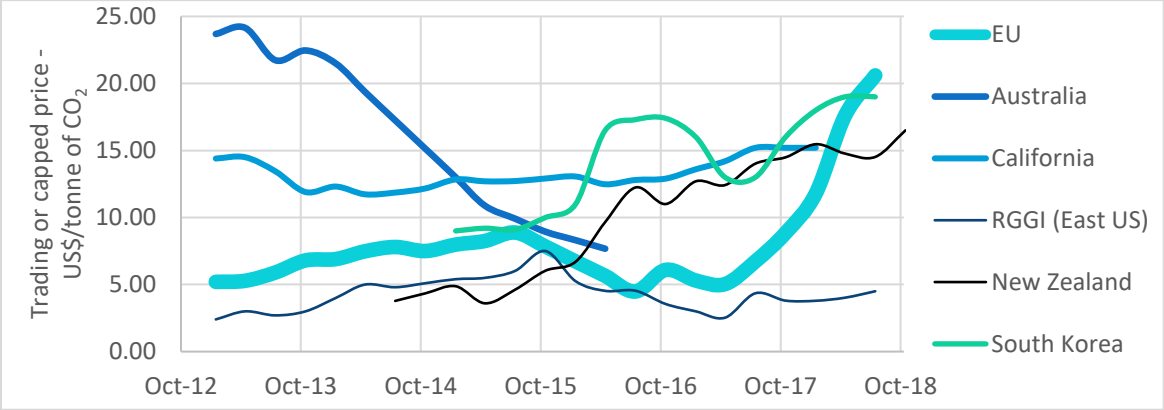
In principle, trading of CO_2 emission permits will allow the free market to establish a least-cost means of incentivising CO_2 emission reduction. The traded price of carbon varies greatly across emission trading schemes (ETS). The largest ETS (in the EU) was trading at around US$15 per tonne of CO_2 in mid-2018 but has recently increased to exceed US$20 per tonne of CO_2 (World Bank 2018). The volatility in the carbon trading market is unhelpful in incentivising long-term infrastructure projects. Figure 1.9 shows the carbon price evolution for six carbon markets.

The thickness of the lines reflects the size of the carbon markets, with the EU ETS being larger than the other markets combined. The Australian ETS commenced with a high fixed price which then reduced with trading, but the supporting legislation has now been repealed.

Figure 1.9 shows a tendency for the carbon markets to converge recently with prices increasing across the markets. That rapid increase in the traded carbon price indicates that the availability of low-cost emission reduction opportunities is declining. The Regional Greenhouse Gas Initiative (RGGI) in the eastern USA is

not increasing as rapidly as the EU ETS, signalling that low-cost emission reduction opportunities are still available in the USA.

Figure 1.9 Carbon Trading Prices in Different Markets



CO_2 = carbon dioxide, EU = European Union, RGGI = Regional Greenhouse Gas Initiative.
Source: Authors.

1.7.3 Emission Limiting Legislation

In contrast with the uncertainties associated with carbon trading and a carbon tax, there would be greater certainty for the designers of new plants to have legislated emission factors, such as kg CO_2/MWh for power plants, kg CO_2/tonne of crude steel, or kg CO_2/tonne of cement clinker. These factors are well understood in the corresponding industries. However, there is no accepted definition of CO_2 emissions per tonne of refined product for the petroleum industry. Fixed emission factors would assist with meeting the Nationally Determined Contributions (NDCs) committed to in the Paris Agreement.

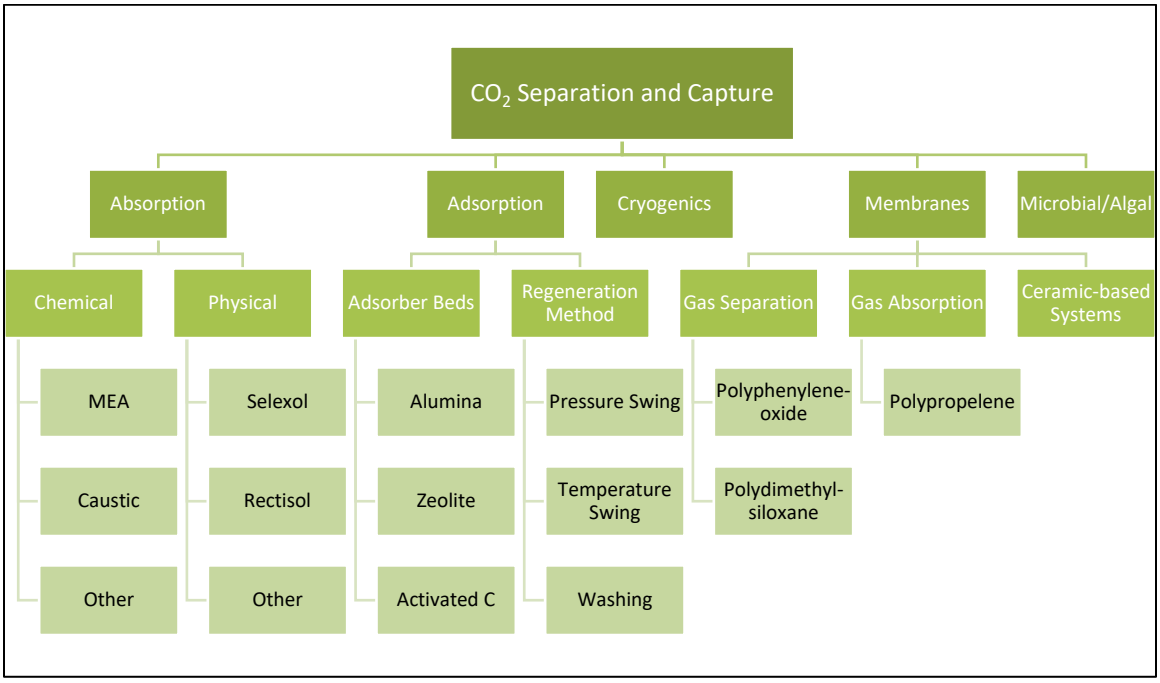
Fixed emission factors would enable plant developers to select the technologies and primary energy sources to meet the criterion. In the case of implementation of CCUS, a fixed emission factor would define the degree of decarbonisation required. Also, a fixed emission factor would help to define capture-readiness levels.

If an individual country sets fixed emission factors for large industries that are out-of-line with neighbouring countries, then there would be a risk of businesses relocating to the neighbouring countries with less stringent regulations. However, that has not been a major issue for the countries with a high carbon tax listed in Table 1.3. The problem of unequal emission factors may be overcome by establishing industry-standard emission factors.

Chapter 2 **Overview of Carbon Dioxide Capture Technologies**

Several technologies exist for the capture of CO_2 from gas streams of industrial processes, such as ammonia and hydrogen production, and energy-related sources, such as flue gases from power plants and furnaces. Figure 2.1 lists the available technologies for CO_2 capture. Most of these are under research and development to improve their capture performance, energy consumption, stability and costs. The choice of technology depends on the characteristics of the gas streams and the required purity of the product gas. Technology options that have been the focus of numerous studies, including pilot and commercial demonstrations, are discussed in the next sections.

Figure 2.1 Technology Options for Carbon Dioxide Capture



C = carbon, CO_2 = carbon dioxide, MEA = monoethanolamine.
Source: Anand B. Rao and Edward S. Rubin. 2002. "A Technical, Economic and Environmental Assessment of Amine-Based CO2 Capture Technology for Power Plant Greenhouse Gas Control," Environmental Science and Technology, vol. 36, no. 20 (2002), pp. 4467-4475.

Technology options for the capture of CO_2 related to combustion are commonly categorized into three major approaches: post-combustion, pre-combustion and oxyfuel combustion.

2.1 Carbon Dioxide Capture Technologies

In post-combustion capture, CO_2 is separated from a stream of flue gases consisting mainly of a rich amount of nitrogen (N_2) from the air, plus water (H_2O) vapor and CO_2 from the carbon and hydrogen in the fuel. Other combustion products such as pollutant sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter may also be present (CRS 2013). The biggest challenge in post-combustion capture is separating CO_2 from a large amount of N_2 in the flue gas (NETL 2019). [6] In a power plant with pollution control systems, post-combustion technologies are typically installed after the flue gas streams have treated and cleaned off pollutants. Several post-combustion technologies such as amine-based absorption, adsorption and membrane separation have been well-investigated and are introduced in the next sections. With some material and process modifications, these technologies may also be applied in pre-combustion CO_2 capture.

2.1.1 Post-combustion Capture of Carbon Dioxide

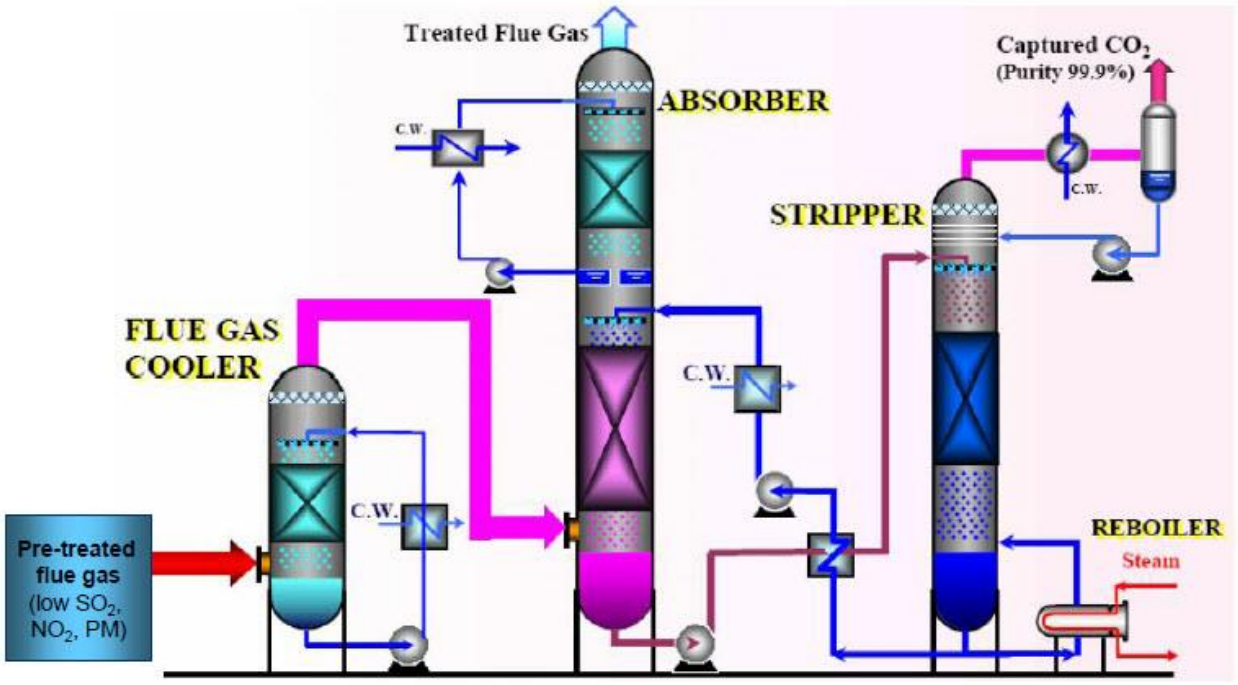
Amine-based Absorption of Carbon Dioxide

Separation of CO_2 from flue gas with an aqueous amine solvent is the benchmark technology for CO_2 capture, particularly where CO_2 capture is to be retrofitted to a typical power plant or an industrial plant that is operating or under construction because the impact on the host plant design is minor. Figure 2.2 shows a generic process flow diagram for post-combustion CO_2 capture with amines. The CO_2 from the flue gases is cooled and then absorbed selectively by the amine solvent. The solvent is then heated and sent to the regeneration column where the CO_2 is stripped with steam from the amine solvent. The amine solvent is cooled and sent back to the absorption column, while the CO_2 is conditioned for transport to use or storage.

The simplest amine is monoethanolamine (MEA). It is well-proven commercially as a reagent for CO_2 capture in many commercial installations around the world (Bhown and Freeman 2011). The use of more complex amine compounds, such as aMDEA (activated methyl diethanolamine) and piperazine and commercial blends of other amine compounds (e.g. Cansolv) have been successfully used in some applications and research into alternative solvent formulation is ongoing.

[6] Typical composition of flue gas from coal-fired boilers may contain 12-14 vol% CO_2, 8-10 vol% H_2O, 3-5 vol % O_2 and 72-77% N_2 (Song et al. 2004).

Figure 2.2 Basic Amine Scrubbing CO2-capture Process Flow Diagram



Source: Authors.

The implementation of amine scrubbing technology faces several challenges including

- Solvent degradation due to impurities such as SO_2 and NOx, which should be reduced to substantially lower levels than typical environmental limits prior to the CO_2 capture process. A benefit from this extra step will be the improvement of air quality in the local environment.
- Solvent losses. The solvent can be entrained in the decarbonized flue gas, so mitigation measures, such as water wash, may be considered to avoid adverse odor effects from the solvent or its degradation products.
- Corrosion due to the aqueous solution of amine solvent, which may be countered with additives.
- Steam demand for the regeneration of the solvent.[7] For a power plant, steam extraction means that less electricity can be produced. For industrial plants, steam may be raised from waste heat on-site, if sufficient, or from an additional source of low-pressure steam.

There is substantial research and development in progress to reduce the energy penalty associated with CO_2 capture with amines. Areas of research include advanced amine solvents, alternative solvent chemistry, improved heat recovery schemes and elevated pressure in the regeneration column. These efforts have yielded incremental improvements in the state-of-the-art commercially available post-

[7] E.g. 3.2 GJ per tonne of captured CO_2 with MEA from coal-fired power plant flue gas. The heat is required in the form of low pressure (0.5 MPa) saturated steam, which can be generated from low-grade heat. If low pressure steam is extracted from a power plant steam cycle the net electricity generation of the power plant may be reduced by about 12-15%.

combustion capture technology and further incremental improvements may be expected to approach the theoretical target of 2 GJ/tCO_2 within the time frame of capture-ready design studies.

Adsorption of Carbon Dioxide

Adsorption is a widely-used technology for the separation of gases. Basic adsorption processes involve cyclic adsorption and desorption through porous solid materials (Berger et al. 2017). Additional steps are usually added to achieve the desired product recovery and purity. For the capture of CO_2 from power plants, pressure swing adsorption (PSA) and temperature swing adsorption (TSA) using different sorbent materials and configurations have been studied.

PSA involves several steps, such as pressurization, feed, blowdown and purge, columns and cycle times (Siqueira et al 2017). A variation of the PSA which was shown to be competitive with amine-based absorption in terms of CO_2 recovery and net electricity efficiency is vacuum pressure swing adsorption (VPSA) using zeolites (Riboldi and Bolland 2017). VPSA, which takes place in fixed-bed columns is most suitable for flue gases with CO_2 concentration greater than 10% requires vacuum pumps, valves and CO_2 compressors (IEAGHG 2014).

Large-scale use of VPSA using zeolites, however, is limited by the unfeasible footprint and number of columns to process power plant flue gas streams. Presence of water of in the flue gas has a detrimental effect on the performance of zeolites, which are hydrophilic and as such need effective water removal system consuming additional energy (Riboldi and Bolland 2017). Further developments on improved adsorbents with higher surface area, such as metal-organic frameworks, and less adsorbent to water, such as carbon-based materials, as well as configurations of PSA processes, remain useful to achieve acceptable energy requirements and sizes of PSA units for CO_2 capture.

TSA relies on changes in temperature between adsorption and desorption for the desired separation of gases (Berger et al. 2017). In a TSA process, adsorption of CO_2 occurs at the adsorption section at low temperature (between 40-60°C), and desorption of CO_2 from CO_2-rich adsorbent at the desorption section maintained at temperature. Adsorption and desorption can also be done in one column by first adsorbing CO_2 and followed by heating to desorb CO_2 (IEAGHG 2014). Configurations of TSA processes for CO_2 capture that have been studied include fluidized, fixed and rotating beds. Adsorbents that have been used for research include supported amines, sodium carbonate material, and structured carbon.

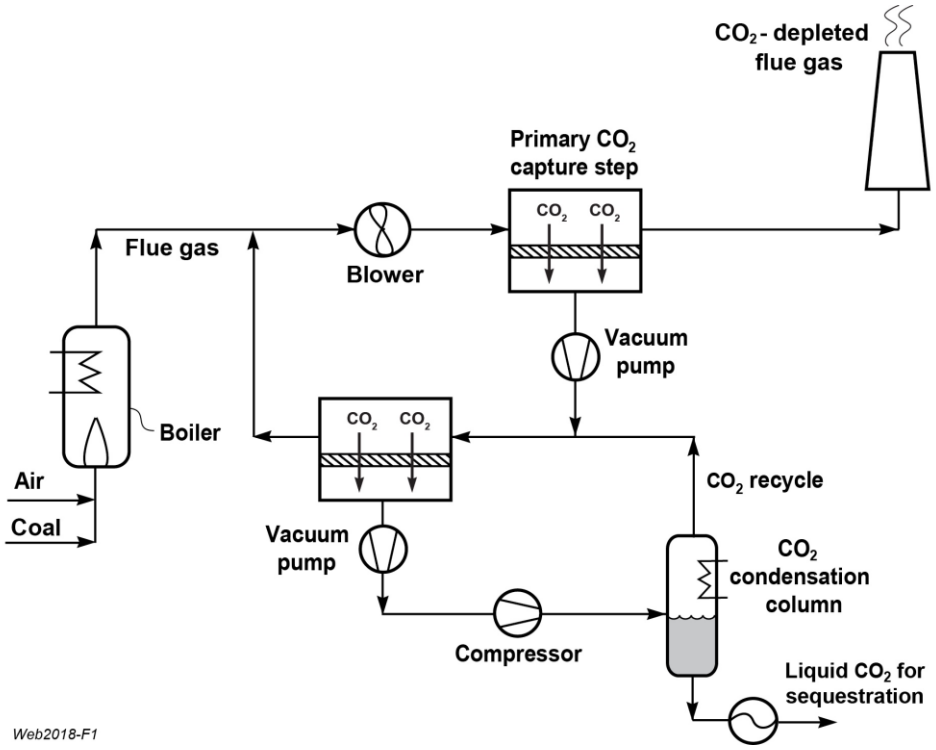
Membrane-based Separation of CO_2

Membranes have been used commercially for the purification of gases, including removal of CO_2 from natural gas (Mustafa, Farhan and Hussain 2016). Separation depends primarily on the selectivity and permeability of the membranes. There are three main types of membranes: ceramic (inorganic), polymeric (organic) and hybrid membranes. Among these types of membranes, polymeric membranes are the most suitable for the option for CO_2 from power plants. Polymeric membranes compared to ceramic membranes, possess better stability and mechanical strength, and easier to be manufactured with a large area (such as required by large-scale applications). Membrane-based separation processes are driven by the pressure difference created by blowers and pumps (MTR 2019), which are its only major energy consumers (Wang et al. 2017).

A commercially available polymeric membrane solution for the capture or CO_2 from coal-fired power plants, cement and steel plants is the Polaris developed by Membrane Technology and Research (MTR

2019). Figure 2.3 presents a diagram of the membrane solution, PolarCap, developed by MTR based on Polaris™. While membrane-based separation technologies have the potential to be low-energy and low-cost CO_2 capture technology options, its use is currently limited by the energy consumption and capability of the pumps and blowers. Very large membrane area would still be required to handle typical flue gas volumes (Wang et al. 2017). Developments are being undertaken by Membrane Technology and Research to improve further the CO_2 capture capability of polymeric membranes (MTR 2019).

Figure 2.3 Membrane Technology and Research PolarCap Process

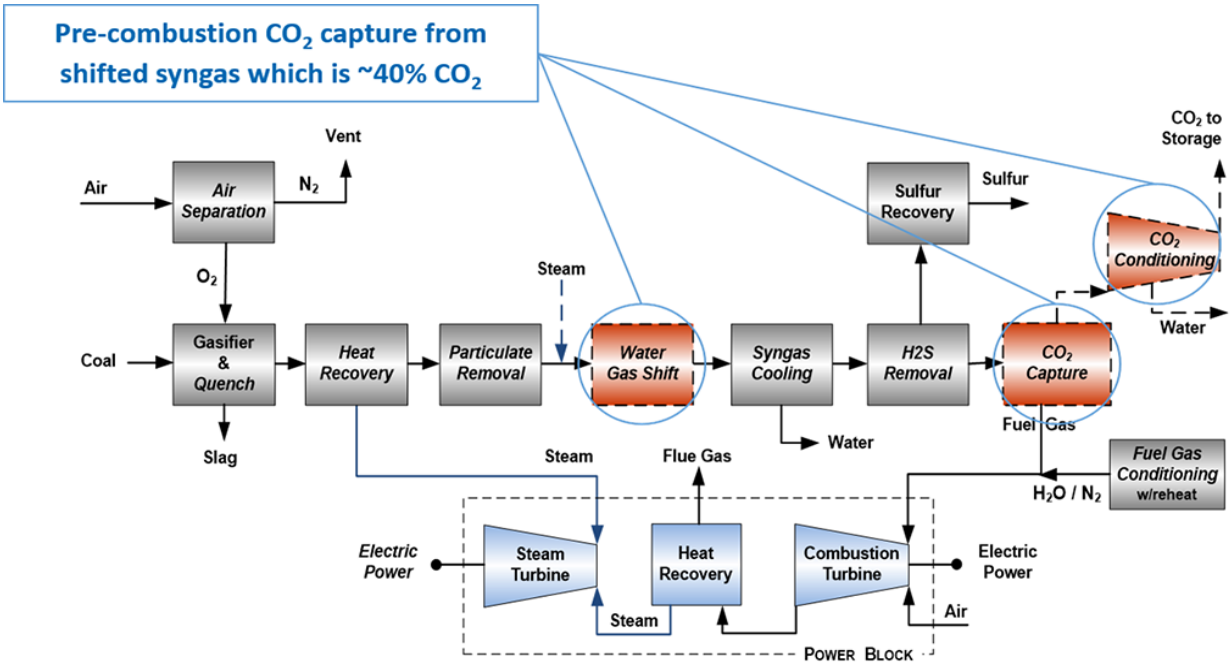


CO_2 = carbon dioxide.
Source: Membrane Technology and Research. 2019. Retrieved from https://www.mtrinc.com/our-business/carbon-capture/coal-fired-power-plants/.

2.1.2 Pre-combustion Capture of Carbon Dioxide

Pre-combustion capture technologies separate CO_2 prior to combustion of fuels in a gasification-based power plant, where hydrocarbon fuels are converted to syngas composed mainly of hydrogen (H_2) and carbon monoxide (CO). To capture CO_2, the CO in the syngas is converted to CO_2 in a water-gas shift reactor, which produces more H_2 along with the conversion of CO to CO_2. The produced CO_2 is then captured before combustion of H_2 as fuel in a combined cycle plant (NETL 2019). Figure 2.4 presents a process diagram for the pre-combustion capture of CO_2 in an integrated gasification combined cycle plant (IGCC). Technologies for the pre-combustion capture of CO_2 include physical and chemical absorption, such as the use of Selexol, a commercially available solvent (CRS 2013). Other potential technologies which are subject of research includes the use of advanced solvents, adsorbents and membranes (U.S. DOE/FE 2019). Compared to post-combustion capture, capture of CO_2 is easier and cheaper in a pre-combustion capture process where CO_2 concentration is high.

Figure 2.4 Process Diagram of Pre-combustion CO_2 Capture and Compression for an Integrated Gasification Combined Cycle Power Plant

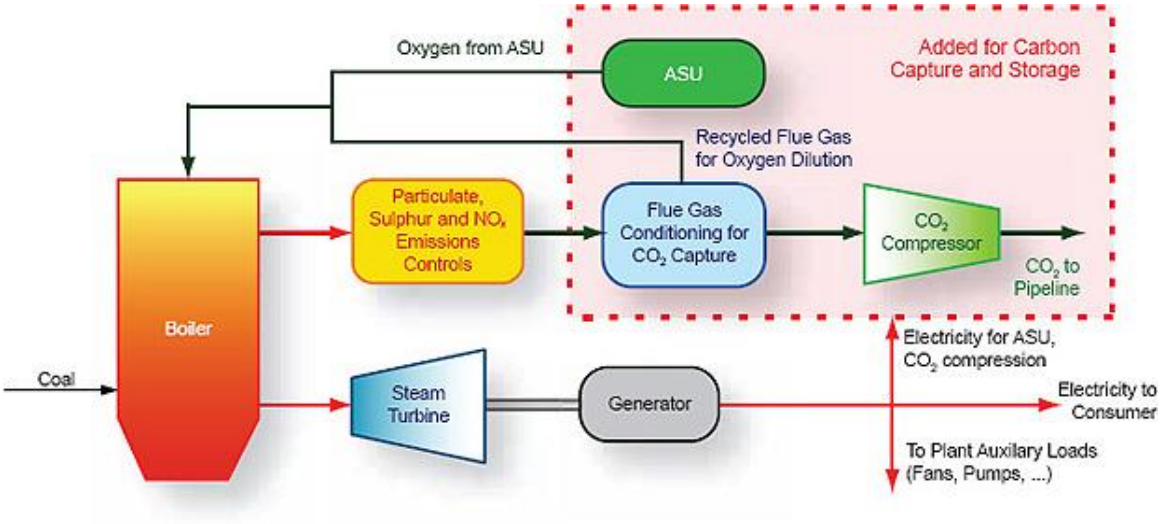


CO_2 = carbon dioxide, H2O = water, H2S = hydrogen sulfide, N2 = nitrogen.
Source: National Energy Technology Laboratory. Pre-combustion CO_2 Capture. Retrieved from https://www.netl.doe.gov/coal/carbon-capture/pre-combustion.

2.1.3 Oxyfuel Combustion Systems

Oxyfuel combustion systems use nearly pure oxygen instead of air for combustion. As such, the combustion flue gas is free of large amounts on N_2, which is a big challenge in post-combustion capture. After removal of small amounts of pollutants, the flue gas from oxy-fuel combustion consists mainly of CO_2 and water vapor. Water vapor and CO_2 can easily be separated by cooling and compressing the flue gas to remove the water vapor. Part of the flue gas is recycled to the boiler to control the combustion temperature, which is much higher when pure O_2 is used instead of air. Oxyfuel combustion systems require an additional air separation unit to produce O_2 of 95-99% purity (CRS 2013). The cost of energy for air separation replaces the cost of energy for CO_2 regeneration in post-combustion capture schemes. Figure 2.5 illustrates a schematic diagram of a coal-fired power plant using oxyfuel combustion. Oxyfuel combustion can be applied to pulverized coal (PC) and circulating fluidized bed (CFB) coal fired power plants and combined cycle gas turbine (CCGT) based power plants. Two variations of the oxyfuel combustions systems—the Allam cycle and chemical looping combustion—are briefly introduced in this section.

Figure 2.5 Oxyfuel Combustion Process Scheme



Source: Global CCS Institute. "Strategic analysis global status carbon capture and storage report 2."

Allam Cycle

The Allam cycle involves the use of supercritical CO_2 (sCO_2) as a working fluid in the turbine cycle. The thermodynamic properties of sCO_2 ensure that the output in terms of electricity is higher than the output obtained by conventional steam or air-based working fluid cycles. This increased output due to an increase in efficiency can partially compensate for the parasitic load of the CO_2 absorption system. Further to that, the size of these turbines is much smaller compared to conventional ones. One of the major reasons for the economic attractiveness of Allam cycle is the production of chemicals (Ar and N_2). This may be good for the first few plants in the area when the market for nitrogen and argon is not saturated. NET Power is one of the first organizations to implement a pilot project based on this principle. US, UK and Japan are associated with this project.[8] A 300 MW plant on this technology is already under planning (Patel 2019a). Figure 2.6 shows a basic diagram of an Allam cycle.

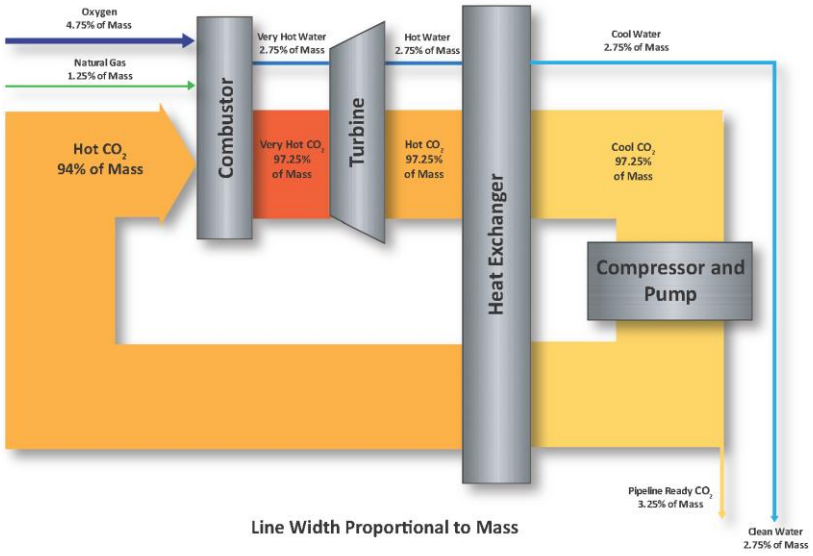
Chemical Looping Combustion

A next-generation oxyfuel combustion technology under development is chemical-looping combustion (CLC). Unlike conventional oxyfuel combustion, CLC systems do not require air separation units since oxygen is produced internally by the process. As shown in Figure 2.7, a CLC system is separated into two reaction zones, the air reactor and the fuel reactor zone. CLC uses a metal oxide to selectively capture O_2 from air in the air reactor. The O_2-carrying metal oxide is then transferred to the fuel reactor where the oxygen reacts with the fuel. The product CO_2 from the reaction can then be captured and transported (Breeze 2015). Current CLC research being done by the National Energy and Technology Laboratory are focused on developing and refining oxygen carriers with sufficient oxygen-carrying capacity and durability,

[8] NET Power. https://www.netpower.com/.

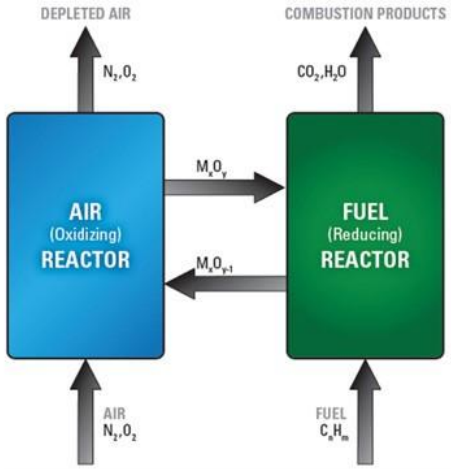
developing effective solids circulation separation and techniques, and overall system design and optimization.

Figure 2.6 Allam Cycle Basic Diagram



CO_2 = carbon dioxide.
Source: 8 Rivers Capital, LLC.

Figure 2.7 Chemical Looping Combustion Diagram



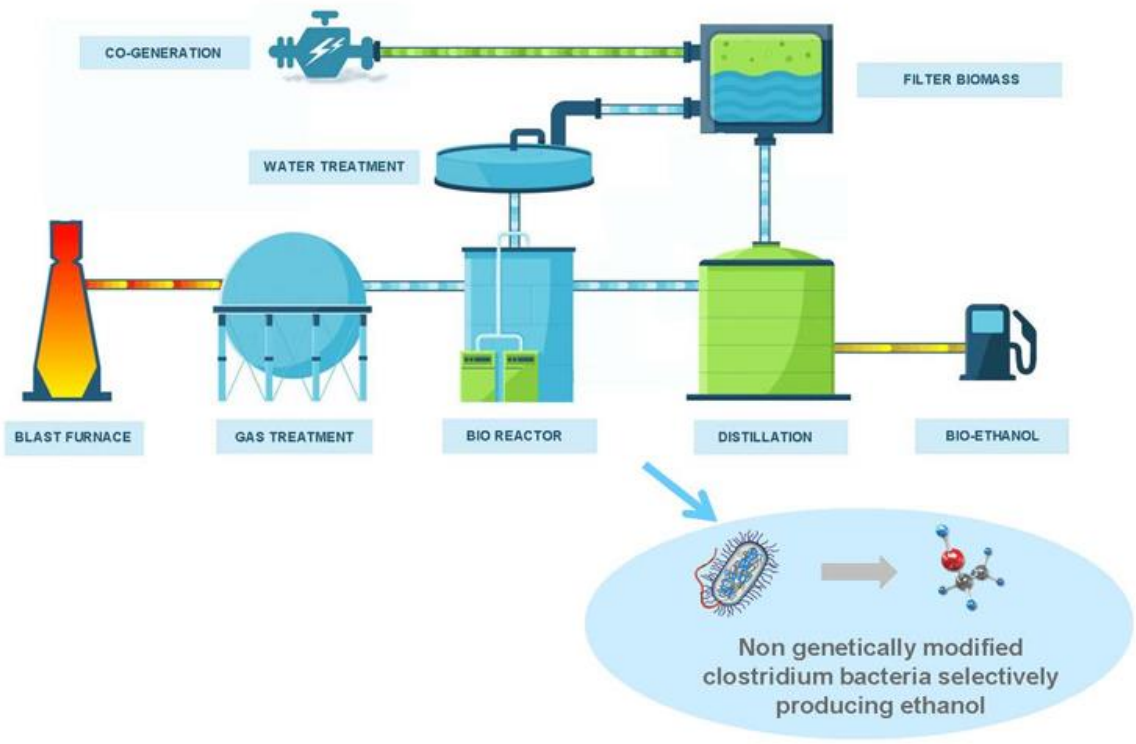
C_nH_m = hydrocarbon fuel, N_2 = nitrogen, H_2O = water, M_xO_y = oxidized metal oxide, M_xO_{y-1} = reduced metal oxide, O_2 = oxygen.
Source: National Energy Technology Laboratory. Chemical Looping Combustion. Retrieved from https://www.netl.doe.gov/node/7478.

2.2 Carbon Dioxide Utilization Technologies

2.2.1 Ethanol from Carbon Dioxide

Steel production and petroleum refining processes produce off-gases containing carbon monoxide, carbon dioxide and hydrogen. Recently, some industries have developed a process to convert such off the gas to ethanol with the help of specialized bacteria. This technology is commercially implemented in steel mills and oil refineries in different parts of the world. Further work in this direction is to make aviation turbine fuels and other chemicals. Figure 2.8 shows a waste CO_2 to ethanol process.

Figure 2.8 Waste Gas-to-Ethanol Process



Source: ArcelorMittal. Retrieved from https://bioenergyinternational.com/biofuels-oils/arcelormittal-and-lanzatech-break-ground-on-eur-150-million-waste-gas-to-ethanol-project.

2.2.2 Mineralization of Carbon Dioxide

Mineralization is one of the most reliable CO_2 sequestration techniques which has long-term storage potential and does not require monitoring. CO_2 mineralization has much longer permanent storage of the CO_2 compared to CO_2 to fuel or CO_2 usage in food. These use eventually, allow CO_2 to escape back into the atmosphere. CO_2 can be stored in cement through CO_2 curing, CO_2 carbonation or as an ingredient of the cement. This technology holds a big promise and may be interesting for the cement companies who may find the mineralized product as a complementary product to their existing line of sellable goods. In case of mineralization, the product as well as raw materials are rather heavy and hence, distance of travel of product as well as raw material plays a role in the profitability of the business.

2.3 Technologies and Infrastructure Enabling the Deployment Carbon Dioxide Capture, Utilization and Storage

2.3.1 Common Carbon Dioxide Infrastructure

Transportation of CO_2 forms a large part of the CCUS value chain. It is similar to common carrier principle followed in natural gas network, oil transportation, power transmission or chemical pipelines. A detailed analysis of sources and sinks of CO_2 in the targeted area will help in designing the route and size of the CO_2 pipeline. Business models can be developed on the basis of the common carrier principle indicated above, and ownership of the infrastructure can be some form of public-private partnership. Such an infrastructure will help in the reduction of the cost and responsibility of running a complex transportation pipeline network. CarbonNet project in Victoria, Australia may be a good example of this.[9] The Oil and Gas Climate Initiative's Kickstarter initiative also aims to achieve similar results.[10]

2.3.2 Combined Stripping of Sulfur Oxides and Carbon Dioxide

Various sulfur oxides (SOx) are generated due to the presence of sulfur in fossil fuel combusted in supplying energy. It leads to acid rain and smog to create environmental hazards. Removal of SOx is a strict requirement in most of the environmental regulations. For countries like Australia, India or Indonesia, which often do not have flue gas desulfurization (FGD) installed at coal-fired power stations, removal of SOx prior to carbon capture becomes a significant additional cost (almost 0.1 million USD/MW). To avoid the having a separate FGD unit prior to CO_2 capture, the Commonwealth Scientific and Industrial Research Organisation of Australia developed a combined capture process, called CS-Cap, which uses a single absorbing liquid to simultaneously capture SO_2 and CO_2 from coal-fired power station flue gas (Pearson et al. 2017). Some of the newer CO_2 absorbents are capable of absorbing both CO_2 and SOx. Thus, taking care of both atmospheric emission and emission of GHG. Such chemicals are available commercially and also used in power plants.

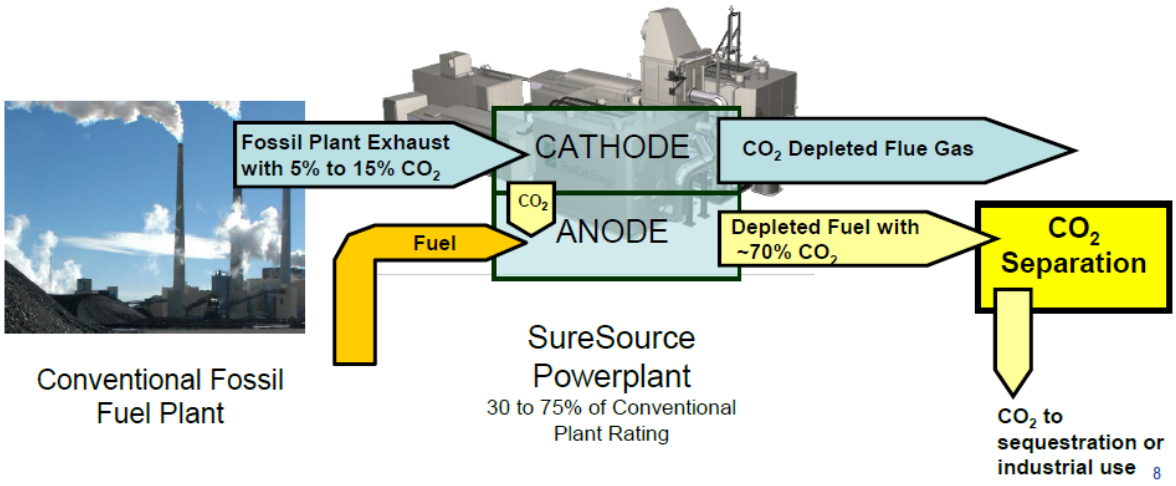
2.3.3 Use of Fuel Cell to Strip Carbon Dioxide

Chemical absorption is the most advanced commercial technology for CO_2 capture. However, the most important challenge with this technology is to limit the parasitic load resulting from chemical plant operation. It consumes almost 20 to 25% of the net power generated from the power plant. It is also a rather complex chemical process and requires considerable attention. It also increases the cost of the power substantially.

CCS with molten carbonate fuel cell involves stripping of flue gases from natural gas or coal-based power plant by passing it through the cathode of the fuel cell. The anode is fed with gaseous fuel such as natural gas, biogas or syngas. The process ensures that a concentrated stream of CO_2 comes out at anode while cathode has CO_2 stripped flue gas. The CO_2 can be directly stored while the fuel cell gives electricity. Figure 2.8 illustrates a concept for the capture of carbon dioxide using a fuel cell.

[9] Earth Resources. https://earthresources.vic.gov.au/projects/carbonnet-project.
[10] Oil and Gas Climate Initiative. https://oilandgasclimateinitiative.com/oil-and-gas-climate-initiative-and-key-governments-crystallise-commitment-to-develop-a-commercial-ccus-industry-worldwide/.

Figure 2.9 Sure Source Powerplant Carbon Capture Concept



CO_2 = carbon dioxide.
Source: Fuel Cell Energy. 2017.

Chapter 3 **Transport, Storage and Use of Carbon Dioxide**

3.1 Introduction to Carbon Dioxide Transport

For CCUS readiness, not only should the routing be identified but a preliminary design of the transport and storage infrastructure (dedicated or shared) should also be carried out, as the developer has to prove to the authorities that retrofitting CCUS on its plant will be technically and economically feasible.

The main requirements for CO_2 transport-readiness studies are the following:

- Locations of CO_2 sources and sinks should be identified;
- Flow-rates and CO_2 conditions at each end of the system should be known (CO_2 capture and injection profiles with peak flowrates);
- Environmental and social constraints should be identified; and
- Infrastructure in place should be identified.

These inputs are required by the CO_2 transport designer to

- Select a means of transport;
- Evaluate if the reuse of existing infrastructure is possible and whether it could allow for potential third-party access;
- Determine preliminary routing and a preliminary design;
- Perform an economic assessment;
- Identify and mitigate risks to implementation;
- Identify who could be building/operating this part of the CCUS chain;
    - If the distance to the storage/use site is short, the capture operator might be in charge;
    - If the distance to the storage/use site is long, a publicly /privately owned organisation, or the storage facility operator, could be in charge of the transport infrastructure;
    - If the infrastructure can benefit several CO_2 sources and sinks, the government could decide to build a collective pipeline and create a public entity to operate it.

When CCUS is implemented, the CO_2 source operator is not necessarily required to build and operate the transport part of the CCUS chain. This part of the chain could be owned and operated by a service provider with suitable technical, economic, and organizational capability.

In this chapter, different modes of CO_2 transport onshore and offshore will be summarised from a technical perspective (transport conditions, drivers for design, time to deployment); a health, safety, and environment (HSE) perspective (eg. inhalation of CO_2); and an economic perspective (generic CAPEX, OPEX, most economical way for different distances).

3.2 Carbon Dioxide Properties and Impact on Transport

CO_2 can exist in four phases: solid, liquid, gas, and supercritical fluid. At ambient conditions, CO_2 is a gas. At high pressure and ambient temperature, it is a liquid. Above 31.1^{o} C is a supercritical fluid. Solid CO_2 (dry ice) forms below about -56°C. At pressures above its critical pressure (7.4 MPa), CO_2 does not change phase with changes in temperature; especially no volume change occurs. It is either liquid or supercritical, which is the so-called “dense phase” (ISO 2016).

Four means of CO_2 transport are possible: truck, train, offshore and/or onshore pipeline, and ship. The first two modes of transport are only suited to small quantities for economic reasons. In these cases, CO_2 is usually in chilled liquid form, close to the triple point (-56.6°C, 0.51 MPa). For more sizeable quantities, pipelines and ships are more cost-effective.

The CO_2 density in the gaseous form is very low (1.815 kg/m^3 at NTP conditions) and is not favoured for transport because that would require the construction of very large facilities. However, for the Total pilot in Lacq-Rousse, France, a natural gas pipeline was re-used and could only accommodate a design pressure of 2.7 MPa so CO_2 was transported as a compressed gas.[11] However, CO_2 transport by pipelines is typically in dense phase at pressures above the critical pressure.

Chilled liquid CO_2 is envisaged for ships (0.7 MPa,-50°C or 1.5 MPa,-30°C) but is unsuited for pipelines because a refrigeration process and thermal insulation of the pipeline would be required (Gassco 2017).[12] For transport by ships, the concept of very high-pressure (>7 MPa), uninsulated CO_2 onboard (transported in the dense phase as for a pipeline) was developed by Knutsen OAS Shipping but remains unproven.

For short distances between capture and storage sites, technical and economic assessments should compare transport in the gaseous phase (large infrastructure), in the dense phase (with the cost of CO_2 compression) or in the chilled liquid form (with the cost of CO_2 refrigeration and thermal insulation of the pipeline). The delivery pressure will be a factor that impacts this choice.

Box 3.1: Existing Experience in Carbon Dioxide Transport

Onshore CO_2 pipelines—More than 7000 km of CO_2 pipelines are laid in North America. They carry 70 MtCO_2/y for Enhanced Oil Recovery (EOR) purpose.[a] CO_2 in these pipelines is in dense phase at a pressure above 7.4 MPa.

Offshore CO_2 pipeline—There is one offshore CO_2 pipeline in operation in the Barents Sea (~150km) that was built for the reinjection of CO_2 at 15 MPa and 9°C into aquifer storage under the Snøhvit field. The CO_2 is from the onshore LNG facility in Melkøya that processes natural gas from Snøhvit.

Liquid CO_2 transport by ships is mainly used for applications in the food industry. The European market is approaching 3 Mt/y. In this context, a small fleet of small ships transporting CO_2 is operated by Larvik Shipping and Anthony Veder. The tank capacities of these ships are between 1220 and 1850 m^{3,} and they are transporting CO_2 at a pressure around 1.9–2.0 MPa and a temperature around -30°C.[b] In addition, the shipping company IM Skaugen has six 10,000 m^3 ships in their fleet which are rated to 0.7 MPa, -104°C, because their normal cargo is LPG or ethylene, but they are also registered for carrying liquid CO_2.

CO_2 transport by trucks and trains is in refrigerated tankers/trailers to transport food-grade CO_2 at pressures below 1.8 MPa and temperatures around -23°C. The Gundih Pilot CO_2 project in Central Java, Indonesia has envisaged transport by truck in its preliminary design.

[a] US DOE NETL. 2015. "A Review of CO_2 Pipeline Infrastructure in the U.S."
[b] Brownsort, Peter. 2015. Ship transport of CO2 for Enhanced Oil recovery - Literature Survey. SCCS. http://www.sccs.org.uk/images/expertise/reports/co2-eor-jip/SCCS-CO2-EOR-JIP-WP15-Shipping.pdf

[11] CO_2 gas density at 2.7 MPa is about 58 kg/m^3. Dense phase CO_2 is over 800 kg/m^3
[12] Design studies suggest that 1.5 MPa might be an optimum pressure for ship transport of CO_2

3.2.1 Impurities in the Carbon Dioxide Stream

The impurities in the CO_2 stream will vary depending on the source; and, the capture technology will impact its physical properties and thus impact the design and HSE considerations.

In the case of post-combustion capture, water and amine solvent are the only significant contaminants, which are mostly removed in the CO_2 cooling and compression processes. Some additional dehydration may be required to meet downstream requirements as quantified in transport-readiness studies.

In the case of pre-combustion capture or oxyfuel operation, the acceptable amount of other chemical components will depend on the transport and storage solutions, as assessed by an overall techno-economic optimization of the CCUS chain. Otherwise, the capture operators will have to comply with the specifications set by the transport and storage operators. In these cases, the impurities that could be present in CO_2 are

- Water
- Acid gases (H_2S, SO_2, NOx)
- Non-condensable gases (N_2, O_2, Ar, H_2, CO)
- Heavy metals and particulate matters.

3.2.2 Effect of Water on Carbon Dioxide Transport

Solid CO_2-hydrate can form at temperatures below 10°C. A maximum of 50 ppm water in liquid CO_2 is suggested to avoid CO_2 hydrate formation at practicable operational temperatures (Brown 2017). Hydrate formation is not reported as an issue for CO_2 transport in the United States during winter.

If gaseous CO_2 is dry, (e.g. the relative humidity is less than 60%), then using ordinary carbon steel is possible without corrosion (Seiersten 2001). When CO_2 is separate with an aqueous process, e.g. amine scrubbing, condensation of water will be a part of the CO_2 compression process. Additional dehydration before CO_2 transport may be necessary. The dehydration level will depend on the transport conditions. The maximum allowable water content is still a parameter under discussion.

3.2.3. Health, Safety and Environment Considerations

In addition to general risks associated with using of pipelines or ships for transport, the main HSE risks and mitigation options are specific to leaks of CO_2. For design and HSE considerations, the ISO 27913 (2016) and DVNGL standards (DNVGL Onshore 2018) should be referred to for pipelines. As for ships, the International Gas Carrier Code (2016) applies to ships transporting liquefied CO_2.[13] This code covers all aspects of gas carriers including stability, materials, filling limits, safety systems etc. In addition, for design, DNVGL rules should be referred to (DNVGL Onshore 2018, Pt 5 Ch 7).

Pure CO_2 is colourless, odourless, and non-flammable. It is a non-toxic constituent of air at 400 ppm (0.04%). In unventilated indoor environments, the CO_2 concentration can increase to 0.1%. In submarines, CO_2 content in air can be up to 1%, beyond which the working capability of acclimatised submariners is adversely affected. In human physiology a concentration of 4% CO_2 in the lungs causes exhaling, so inhaling air with a CO_2 concentration in excess of 4% would cause immediate exhaling and hence hyper-

[13] International Gas Carrier Code 2016; see Chapter 17.21 Carbon dioxide high purity and Chapter 17.22 Carbon dioxide reclaimed quality.

ventilation would occur necessitating evacuation from that environment. Part 3.4 of DNVGL-RP-F104 provides a table of effects on human health of CO_2 concentrations and exposure times.

Since CO_2 is heavier than air, a major leak could be a temporary hazard in low lying areas until the CO_2 dispersed. Good ventilation is the remedy for excess CO_2 in the air. Toxic contaminants in the CO_2 stream (e.g. H_2S, CO) can also be safety concerns and should be considered when carrying out a safety risk assessment.

3.3 Routing

A direct route is desirable to minimise cost, but densely populated and protected areas should be avoided. Laying pipelines in such areas could lead to objections from residents and activist groups. In addition, there could be some safety-related issues. As for other pipelines the routing and natural obstacles such as rivers as well as road and rail crossings should be minimised to reduce cost.

Following the existing pipeline rights-of-way with CO_2 pipeline routes is a good way to proceed as the routing was already established and permitting processes might be eased. For example, when building a refinery or a gas-fired power plant, a capture-ready plan might include routing the CO_2 infrastructure alongside existing oil or gas pipelines, with the flow in the opposite direction.

In the case of offshore pipelines; cables, existing pipelines, and shipwrecks are to be avoided or crossed with special caution. Marine activities of boating and fishing have to be considered to avoid any risks of anchors or fishing gear damaging the pipeline, which might need to be protected with a layer of rocks.

3.3.2 Shipping Route

Instead of pipelines, ships can provide an option between two coastal locations as all or part of a CO_2 transport route. The connection could be from one harbour to another with some short onshore pipeline connections from the source or the sink to the harbour. Considering offshore solutions could be a way to avoid densely populated areas or other constraints on land. For the shipping route, following the existing shipping lanes is a good strategy.

If there is a quay for export of products (e.g. cement, from a coastal plant) accommodating a potential CO_2 ship and its associated storage tanks could be part of a CCUS-ready plan. In any case, space should be secured for liquefaction and temporary storage facilities in ship-based systems if the CO_2 is not already prepared to shipping conditions at the capture site.

For both pipelines and ships, stakeholder's concerns and risks along the route have to be identified and assessed to minimize the risk of public opposition and conflicting uses of routes.

3.3.3 Possibility for Reuse of Infrastructure

Re-use of infrastructure is possible for CO_2 transport. However, re-use needs to be planned to follow on from the decommissioning of the existing installations. In addition, the infrastructure characteristics should be requalified for CO_2. Reusing a pipeline may limit the capacity of the transport system due to the diameter of the existing pipeline or its maximum allowable operating pressure.

Semi-pressurized ships are usually designed for a working pressure of 0.5 to 0.7 MPa and operate at low temperature (e.g. -48°C for LPG and -104°C for ethylene). Some ships have already been qualified to be able to transport both CO_2 and LPG even if for now just LPG[14] or ethylene is carried.[15]

3.3.4 Multisource and Multisink CO_2 Transport Infrastructure

Demonstration CCUS projects (e.g. Boundary Dam where CO_2 is captured from one power plant unit for an EOR application) typically involve a single source-to-sink transport pipeline. However, full-scale implementation of CCUS would require integrated transport systems. A study in Indonesia found that a single power plant CO_2 source needed many CO_2 injection points in oil and gas fields, indicating that CO_2 sources might be an order of magnitude larger than individual CO_2 sinks (World Bank 2015).

The following elements should be considered before selecting a transport solution:

- Source–sink matching of capture outputs (short and long term) for single sources or combined sources to storage sites or use inputs.
- Regulatory, environmental and social constraints should be considered.
- Is there any existing infrastructure? Could it be reused?
- Is there a clustering potential?
- Is there potential third-party access and the need for flexibility?

Different solutions for source-sink matching exist, ranging from point-to-point to a grid network containing multiple sources connected to multiple sinks. In Europe, four Cross-Border Carbon Dioxide Transportation Infrastructures are proposed under the Project of Common Interest Scheme.[16]

Even though the need for cross-border infrastructure for CCUS has been identified in several countries, the international legal instruments are not yet in place. The London Protocol which prevents marine pollution by dumping of wastes and other matter was amended in 2006 to include in its list of exceptions CO_2 and amended again in 2009, to open for cross-border transportation of CO_2 for storage. The last amendment has not entered into force as it has not been ratified by enough members (at least 29 States) (Ombudstvedt 2017). In Asia, only China, Japan, South Korea and the Philippines are Contracting Parties to the Protocol (IMO 2018), but none has ratified the amendment for now. If cross-border transport is identified as required (because of, e.g. lack of storage capacity in a country or public opposition), countries would have to enter bilateral or multilateral agreements.

[14] Design studies suggest that conditions of 1.5 MPa and -30^{0}C may be optimum for ship transport of CO_2.
[15] In contrast liquefied natural gas (LNG) is transported at -162°C and atmospheric pressure.
[16] The European Commission defines projects of common interest (PCIs) as “key infrastructure projects, especially cross-border projects, that link the energy systems of EU countries.” Projects of common interest are intended to help the EU achieve its energy policy and climate objectives (European Commission 2018).

3.4 Economic Considerations for Carbon Dioxide Transport Options

3.4.1 Pipeline Costs

Pipeline transport as a mature technology has little scope for cost reductions. Economies of scale could be achieved by utilizing a network of pipeline shared by several emitters (King Abdullah Petroleum Studies and Research Centre 2011).

Pipeline costs are generally characterized by high CAPEX and low OPEX (1.5%–5% per year of the CAPEX). Pipeline CAPEX is reported in $/km-inch (i.e., cost per kilometres of length x inches of internal pipe diameter and also depends on variation in steel costs).[17] CAPEX estimates range from $67,000/km-inch[18] (Zero Emissions Platform [ZEP] 2011, CO2Europipe 2018), up to $127,000/km-inch for small flowrate, short distance pipelines, and $80,000 to $160,000/km-inch for off-shore pipeline (Vermeulen 2012). Pipeline OPEX, onshore and offshore, were estimated at $8,000 – $9,300 per km per year (ZEP 2011, CO2Europipe 2018). Costs of offshore pipelines are generally 40% to 70% higher than onshore pipes of the same size (King Abdullah Petroleum Studies and Research Centre 2011). These costs assume that the supply pressure would be sufficient to avoid the need for additional pumping. These costs are not based on technical pre-feasibility studies and therefore should be considered as preliminary and approximate estimates. Detailed, exact and reliable cost data for pipeline construction costs are difficult to obtain unless proper pre-feasibility studies have been carried out. The cost models mentioned have been developed by European and American modellers and rely on an annually published pipeline cost database. Such a database does not account for the cost estimates that may be applicable in developing countries where land, labour, materials, and relative right of way costs are expected to be lower.

A pre-feasibility study performed in Asia reported costs around $50,000–60,000 per km-inch for onshore pipelines (World Bank 2015). It showed offshore pipeline costs in the shallow water of $75,000 per km-inch. Maintenance costs were estimated at 3% per annum of the CAPEX. This study also reports that costs for pipelines are generally 30% lower in Asia than in Europe.

3.4.2 Ship Transport Costs

Ship transport costs are characterized by lower CAPEX and higher OPEX than pipelines. The equipment to be included in the cost assessment are liquefaction, buffer storage, the quay with its loading and mooring facilities at the export harbour, the ships, and the offloading facility. In addition, fuel, harbour fees and crew costs will be key in the OPEX assessment. Table 3.1 reviews component costs.

Total ship transport costs in Europe are around 15 to 35 $/t$CO_2$ depending on the distance and the flowrate. The costs for Asia should be around the same. Figures 3.1 and 3.2 present data for CAPEX and OPEX for ship transport of CO_2.

[17] Converted from source data in €/km.inch with an exchange rate of $1=€0.75 in 2010.

[18] NB. This unit cost varies from one geography to the other and in Pakistan for example, the average actual cost of construction came out to be: $33,000 per km.inch for onshore pipeline.

Table 3.1 Cost Components for Ship Transport

Component	Base scale	Units	CAPEX (million $)[a]	Fixed OPEX	Source
Liquefaction and refrigeration	20	$MtCO_2/y$	196	5%	b
Buffer storage at the harbour	1,000	m^3	1.33	5%	b
Loading equipment	3	$MtCO_2/y$	13	2%	c
Ships	25	$ktCO_2$	59	3.3M$/y	d
	35	$ktCO_2$	80	3.3M$/y	d
	45	$ktCO_2$	80	3.3M$/y	d
Off-loading system	1,200	tCO_2/h	40	5%	c, e
Conditioning before injection	350	tCO_2/h	2.7	5%	c

CAPEX = capital expenditure, m^3 = cubic meter, M$/y = million US dollar per year, $MtCO_2/y$= million tons carbon dioxide per year, ktCO2= kilotonnes carbon dioxide, OPEX = operating expenditure, tCO_2/y = tonnes carbon dioxide per year.

[a] Converted from source data in € with an exchange rate of $1=€0.75 in 2010.

[b] ZEP. 2011. "The Costs of CO_2 Transport. Post-demonstration CCS in the EU."

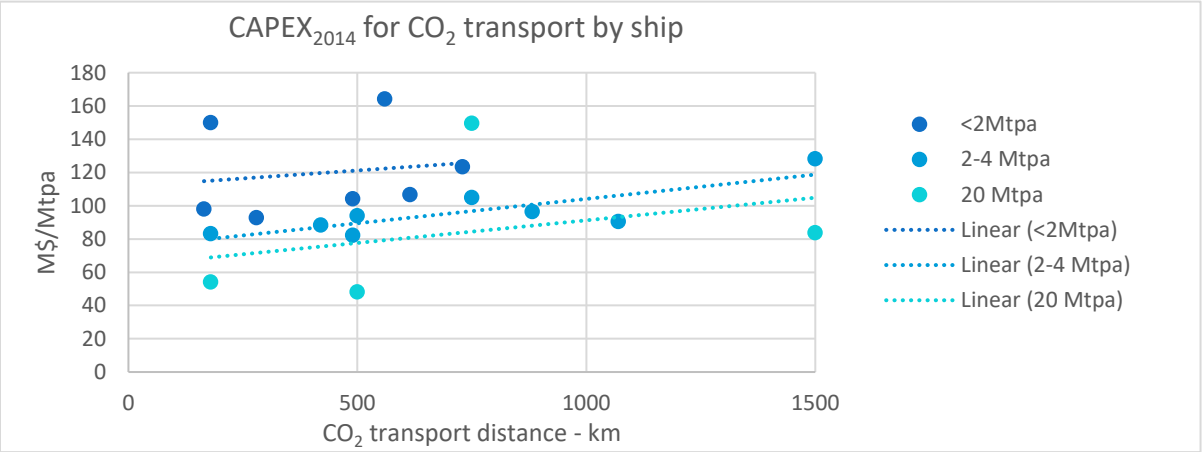
[c] Apeland, S., et al. 2011. "Towards a transport infrastructure for large-scale CCS in Europe. Kårstø CO2 pipeline project: Extension to a European case." CO2Europipe, D4.3.2. 1-84.

[d] Roussanaly, S., et al. 2013. "Costs benchmark of CO_2 transport technologies for a group of various size industries." International Journal of Greenhouse Gas Control, 12, 341-350.

[e] Kjärstad. 2016. "Ship transport—A low cost and low risk CO_2 transport option in the Nordic countries." International Journal of Greenhouse Gas Control, 54 168–184.

Source: Marlinde Marissa Jasmijn Knoope. 2015. *Costs, Safety and Uncertainties of CO_2 Infrastructure Development.*

Figure 3.1 CAPEX for CO_2 Transport by Ship in Europe



CAPEX = capital expenditure, CO2 = carbon dioxide, km = kilometre, Mtpa = million tonnes per annum.

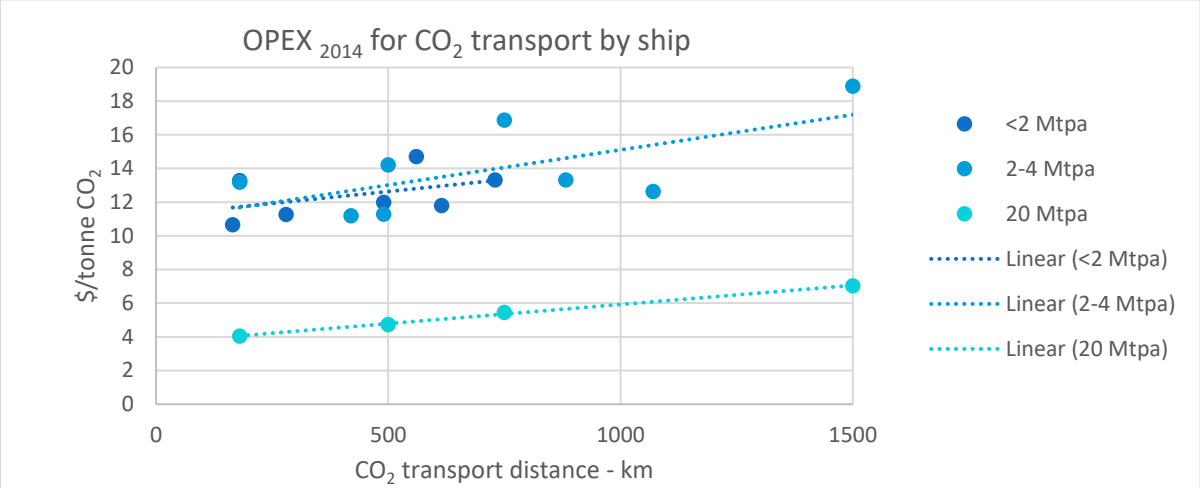
Assumptions and references:

a. Kjärstad et al. (2016)—From a source located in a harbour to offshore storage. Maximum size of 42 kilotons for ships, transport at 0.7 MPa and -50°C, speed 15 knots. Cost for liquefaction, intermediate storage (on barges with volumes corresponding to a number of ships required for the transport), port fees and loading/unloading included—unloading scheme based on Sub-merged Turret Loading (STL). Subsea template and wellhead costs included.

b. ZEP 2011—From a source located in a harbour to offshore storage. Maximum size of 42 kilotonnes for ships, transport at 0.7 MPa and -50°C. Cost for liquefaction, intermediate storage (on barges with volumes corresponding to number of ships required for the transport), port fees and loading/unloading included. Unloading scheme based on STL. Ship manufactured in the Far East. Far East sourcing of crew. Converted at $1=€0.75 in 2010. Inflated from 2010 to 2014 at 3% p.a.

Sources: Authors.

Figure 3.2 OPEX for CO_2 Transport by Ship in Europe



CO_2 = carbon dioxide, km = kilometre, Mtpa = million tonnes per annum, OPEX = operating expenditure.
Assumptions and references:
a. Kjärstad et al. 2016—From a source located in a harbour to offshore storage. Max size of 42 kilotons for ships, transport at 0.7 MPa and -50°C, speed 15 knots. Cost for liquefaction, intermediate storage (on barges with volumes corresponding to number of ships required for the transport), port fees and loading/unloading included. Unloading scheme based on Sub-merged Turret Loading (STL). Subsea template and wellhead costs included.
b. ZEP 2011—From a source located in a harbour to offshore storage. Max size of 42 kilotonnes for ships, transport at 0.7 MPa and -50°C. Cost for liquefaction, intermediate storage (on barges with volumes corresponding to number of ships required for the transport), port fees and loading/unloading included. Unloading scheme based on STL. Ship manufactured in the Far East. Far East sourcing of crew. Converted at US$1=€0.75 in 2010. Inflated from 2010 to 2014 at 3% p.a.
Sources: Authors.

Table 3.2 summarizes the pros and cons of offshore pipelines and ships, in cases when both technologies can be considered.

Table 3.2 Pros and Cons of Transportation Options

	Pros	Cons
Offshore Pipeline	Existing technology Suited for large quantities Low OPEX Not affected by weather Continuous operation Automation possible	**Low flexibility** **High CAPEX** **Long construction period**
Ship	**High flexibility** **Low CAPEX** **Short project delivery time**	**Knowledge gaps (large scale ship operation and off-loading systems)** **Need some buffer storage onshore;** **Discrete cycles;** **Limited capacity;** **High OPEX + harbour fees;** **More CO_2 emitted during transport;** **Sensitive to weather conditions**

CAPEX = capital expenditure, CO_2 = carbon dioxide, OPEX = operating expenditure.
Source: Source: King Abdullah Petroleum Studies. 2011. Carbon Capture and Storage: Technologies, Policies, Economics, and Implementation Strategies.

3.4.3 Dependence of Transport Option on Flowrates and Distances

For on-shore transport of CO_2, the choice is between road, rail, or pipeline. There are few public studies focusing on the transport costs of small flowrates of CO_2. A recent paper by Psarras et al. (2017) estimated that the cost of truck transport was lower than a pipeline for flows less than 100 $ktCO_2/y$ in the US. However, it should be noted that there are logistical issues that limit large volumes of CO_2 to be transported by truck, such as road congestion, as well as safety and environmental concerns associated with heavy truck traffic. It is difficult to say when a pipeline is more cost-competitive than a truck or a train because it depends on the circumstances.

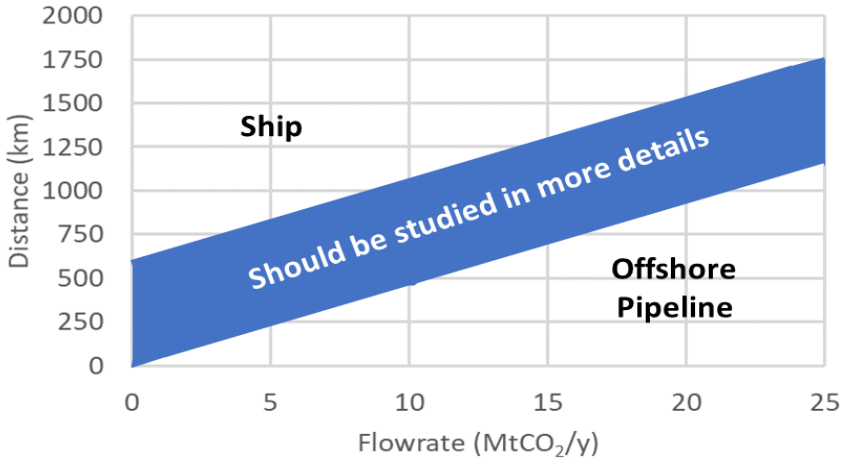
In general, pipelines will be the preferred option for industrial-scale CO_2 transport on land. Dense phase transport will generally be the optimum, but there may be circumstances in which gas-phase transport is preferred.

For off-shore transport of CO_2 the choice is between ship transport and off-shore pipeline. For pipeline transport, liquid CO_2 just needs to be pumped to 8–10 MPa. For ship transport, the liquid CO_2 needs to be refrigerated to -30°C (1.5 MPa) or -50°C (0.7 MPa), which incurs a significant additional energy penalty. In view of the additional energy penalty for refrigeration, the higher-pressure option is preferable.

A small number of studies look at the comparison between offshore pipelines and ships. Most of these studies focus on Europe. In South Korea, a study showed that for a distance of 700 km (+60km onshore) and a flow rate of 1.8 $MtCO_2/y$, shipping was more cost-effective than a pipeline for transporting CO_2 from Western parts of South Korea to the East Sea (Yoo et al. 2013). For the same flowrate but a shorter distance (~250 km) pipeline and ship options result in similar costs. Figure 3. was developed to illustrate the impact of distance and capacity on the choice of transport mode.

Ship transport is competitive for longer distance and smaller quantities of CO_2. Besides distance and quantity, other parameters to consider when considering ship transportation include loading terminal location, water depth, fuel cost, safety, and specifics of the country (IPCC 2005).

Figure 3.3 Illustrative Figure for Choosing the Most Economical Solution between Ship and Offshore Pipeline



km = kilometre, $MtCO_2/y$ = metric tonnes CO_2 per year.
Sources: Authors.

3.4.4 Estimation of Expenses for Transport-Readiness

For transport-readiness, it is necessary to perform techno-economic studies. Around three man-months are expected to be required for such pre-feasibility studies depending on the complexity of the transport system. Those studies might show that early investment in acquiring land rights or access could be necessary to limit the risk of barriers eventuating to prevent later implementation of CCUS.

3.4.5 Examples of Costed CCUS Transport Studies

CCUS readiness studies have been carried out in Asia and elsewhere for power plants. Box 3.2 below details the transport options selected for three examples of CCUS-ready power plants.

Box 3.2: Examples of CCUS Readiness Projects

Indonesia

The study was performed for two power plants: one in West Java and one in South Sumatra. The results presented below are for the power plant in West Java.

Assessment produced in the context of a capacity building program in the country.

CO_2 source: a 2 x 1000 MW lignite-fired power plant in West Java (10.9MtCO_2/y captured), using coal from Kalimantan or Sumatra.

CO_2 sink: storage onshore/ offshore depleted gas fields in West Java

Studied transport option: onshore and offshore pipelines

Lessons learnt: Routing: follows existing natural gas pipeline routing

Even if the unit cost of the offshore pipeline is 50% higher than the onshore pipeline one ($ 75,000 vs 50,000/km-inch), the proximity of the offshore fields makes the offshore and onshore options similar in capital cost (Onshore distribution network of 500 km with a 34" diameter 180 km long backbone. No pressure boosting stations required. An offshore distribution network of ~400 km with a 30" diameter 90 km long backbone).

The study cost NA funded by International Bank for Reconstruction and Development/ The World Bank

Source: World Bank. 2015. "Carbon Capture and Storage for Coal-Fired Power Plants in Indonesia."

United Kingdom

Assessment produced in accordance with the requirements of the Department of Energy and Climate Change (DECC) November 2009 carbon capture guidance "Carbon Capture Readiness (CCR) – A Guidance Note for Section 36 Electricity Act 1989 consent applications."

CO_2 source: Eggborough CCGT plant - 3 single shaft CCGT H Class units up to a maximum of 2,500 MW

CO_2 sink: Indefatigable and Lemen platforms on offshore depleted gas and condensate fields.

Studied transport option: onshore and offshore pipeline – 4.25MtCO_2/y

Lessons learnt: Routing: onshore, an indicative route corridor of 1 km in width for approximately 10 km has been shown taking into account (1) an exit point from the Site unlikely to be blocked by future developments outside of the Site boundary; and (2) the presence of residential areas, natural and built linear infrastructure (such as rivers, rail lines and motorways), and designated sites, such

as Sites of Special Scientific Interest (SSSI), Special Areas of Conservation (SAC), Special Protection Areas (SPA), Ramsar Sites, National Nature Reserves (NNR), Designated Parks and Gardens. Then the proposed route joined a previously proposed pipeline route: the Humber CO_2 pipeline. A pipeline corridor of 10 km is shown. Offshore, a route was identified, avoiding the major infrastructure in the North Sea (production platforms and offshore wind farms).

Transport cost: An economic assessment was performed considering data from publicly available documents (Kingsnorth, Longannet and Peterhead carbon capture competition). It resulted in a cost for transport of £10/tCO_2 for a 35-year project lifetime.

Study cost: NA. Funded by Eggborough Power Limited

Source: Eggborough Power Ltd. (2017).

Gaojing CHP Plant

Assessment performed in the context of the formulation of a CCUS readiness plan for natural gas-based CHP plants

CO_2 source: Gaojing CHP plant is located on the west side of Beijing

CO_2 sink: various oil/gas wells to the south and south-west of Beijing

Studied transport option; onshore dense phase transport - 3MtCO_2/y

Lessons learnt: Routing should bypass Beijing and its suburbs because of the high population density. An intermediate boosting station may need to be constructed. 60 km – 14" pipeline

Pipeline cost: US$ 57,124 per km-inch

Maintenance cost = 3% CAPEX

Study cost: NA. Funded by the Carbon Capture and Storage Fund under the Clean Energy Financing Partnership Facility – ADB

Source: ADB. 2014. "People's Republic of China: Study on Carbon Capture and Storage in Natural Gas Power Plants."

3.4.6 Options for Financing Transport in CCUS Readiness

For CCUS readiness studies carried out in Europe so far (for power plants), the transport parts involved studies of routing, preliminary designs of the transport systems and assessment of the costs of the infrastructure. Neither land nor specific equipment was purchased. Developers funded the costs of these studies in the interests of future-proofing their investment.

In other countries, there are (or have been) some specific CCUS funds that could help fund these studies as shown in Box 3.2 (e.g. Carbon Capture and Storage Fund under the Clean Energy Financing Partnership Facility – ADB / IBRD- the World Bank for capacity building studies).

In Alberta, the Province has decided to fund a pipeline that would collect around 15 MtCO_2/y from some industrial plants and would send it to storage or use (Alberta Carbon Trunk Line) without having specific sources in mind.

In the UK and Norway, it was suggested that a public entity should support the costs of transport and storage, but nothing has been said about funding transport-ready and storage-ready studies as it is not relevant in these countries (no new industry, few power plants).

EOR activities with clear additional revenue streams or an established price on the geological storage of CO_2 could reduce reliance on funds and subsidies. This would not be available for all CCUS projects. A discussion on CO_2 utilisation possibilities is included in Box 3.5. EOR is the principal CCUS mechanism. An analysis of the scope for EOR as a CO_2 utilisation mechanism in China is presented in Box 3.6.

The question is whether compiling a transport study for CCUS readiness could be funded by Carbon and Climate Finance sources as it is not a CO_2 mitigation option as such, but a way to facilitate CO_2 mitigation in the future (an option) so studies will not directly qualify for this type of funding.

Local governments need to provide sufficient financial and policy incentives for developing transport-readiness studies.

Box 3.3: Project of Common Interest

The European Commission has, since 2013, operated a scheme to enable the development of key energy infrastructure projects, known as projects of common interest (PCIs), which is designed to optimize network development at the European level for the period up to 2020 and beyond. The aim of this scheme, implemented by the EU, is to meet the EU's energy policy objectives of competitiveness, sustainability and security of energy supply. As part of this, the EU must prepare the infrastructure for further decarbonization of its energy system in the longer term towards 2050. Every two years, the EC announces the EU's list of PCI projects that can benefit from accelerated permitting procedures and improved regulatory conditions. Considering the strong potential for CCUS hub and cluster developments in Europe, the EC sought to promote the development of future infrastructure requirements for CCUS. For the first time since the PCIs scheme started, the 2017 list of proposed PCIs includes 'Cross-Border Carbon Dioxide Transportation Infrastructure' – a thematic area focused on the development of CO_2 transportation networks. Four CCUS projects are proposed. Projects of Common Interest are then eligible for funding from the Connecting Europe Facility (CEF), the EU's €30 billion (US$40 billion) fund for boosting energy, transport, and digital infrastructure.

Source: European Commission. 2018. *Projects of Common Interest.*
https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest

3.5 Timeline for Carbon Capture, Utilization and Storage-readiness in Carbon Dioxide Transport

Even if a plant is transport-ready, implementing the chain might take several years. This will depend on the distance between the source and the sink and also, for example, on the ease of obtaining rights of ways for onshore pipelines. If ship transport is considered, building the ship will not be on the critical path but it is important to understand what "ready" means in terms of time to implementation.

Some examples of the timing of deployment (from the first identification of the need for a transport solution to actual use, including planning, engineering, and installation) are (ZEP 2011)

- Offshore pipelines: 4.5 to 6.5 years;

- Onshore pipelines: 4 to 6 years;
- Ship: 2 to 3 years.

3.6 Carbon Dioxide Storage

Identification of a CO_2 storage location is a critical element of CCUS readiness. Up to now, large scale CO_2 storage has been considered in porous geological formations (e.g. depleted oil and gas fields and deep saline aquifers). Potential for a large-scale CO_2 storage site requires the following conditions to be met:

- Reservoir rocks with known and suitable characteristics (thickness, high porosity, high permeability);
- The reservoir at an appropriate depth (> 800 m) and pressure, to store CO_2 in dense phase and maximize the capacity;
- Reservoir rocks are overlain with a cap rock that is impermeable, continuous and reliable for geological times;
- The capacity and injectivity of the storage site can accommodate over the long term the volumes of CO_2 that will be sent to the site; and
- Site-specific features such as faults, existing wells, stress fields, and hydrodynamics do not adversely affect CO_2 confinement (King Abdullah Petroleum Studies and Research Centre 2011)

The CO_2 will be trapped trough different trapping mechanisms: first, the structure and stratigraphy will contain the CO_2, then it will be trapped in the pore space (residual trapping), it will dissolve in the formation liquid (solubility trapping) and eventually react with reservoir rocks to form new solid minerals.

Before injecting any CO_2, there are several steps to be carried out:

- the site(s) must first be identified through an appropriate screening step;
- the site(s) must be confirmed through an appropriate appraisal plan;
- permits must be obtained, and injection tests carried out; and
- the site can then be designed and built.

Depleted oil and gas fields have the advantage that they have already been characterized in the past, that they have a proven cap rock and that historical production data exist which make the modelling part of the work easier. Reusing wells could be an option if the wells were not already abandoned and sealed with cement. However, the existence of wells should also be studied with care as the existing wells could be potential migration pathways for the CO_2. Oil and gas fields operators could consider CO_2 storage as a potential new business for their fields once depleted.

For deep saline aquifers, new data must be acquired to properly characterize them. Deep saline aquifers generally offer much larger capacity than depleted fields on a theoretical basis. Complex details such as, in particular, the rate at which the CO_2 can be injected (and adsorbed), the rate at which its pressure dissipates through the reservoir, and how these factors change with time (relative permeability effects) have to be determined (Spero et al 2013). This concept is illustrated in Figure 3.4 (CO2CRC) which shows that while countrywide screening can provide a large storage space (base of pyramid) comprehensive site characteristic assessment can significantly reduce the usable the usable capacity (apex of pyramid) (CO2CRC). Estimates of potential CO_2 storage capacity, such as presented in Table 3.3, need to be qualified

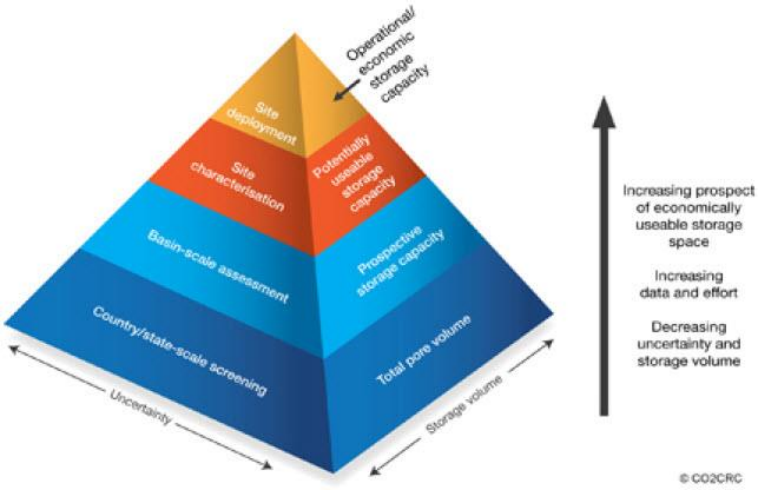
by the status of the storage assessment. For example, the estimate of 1,573 $GtCO_2$ potential storage capacity in China reported by GCCSI contrasts with an assessment of an effective CO_2 storage capacity in China between 65 $GTCO_2$ and 1,551 $GtCO_2$ (Holler and Viebahn 2016).

Four projects mentioned in Box 3.3 are storing CO_2 in deep saline aquifers. The Sleipner project in the Norwegian North Sea has been storing CO_2 for more than 20 years and a total of about 18 million tonnes of CO_2 (0.18 $GtCO_2$) has been stored and monitored to date.

ISO 27914 2017 provides standards for the safe site selection, design, operation, and closure of geologic CO_2 storage projects and should be referred to when performing a storage ready study.

The EU adopted, on 23 April 2009, a Directive on the geological storage of CO_2 to regulate the safe and environmentally sound storage of captured CO_2 (EU 2009). The Directive sets out a regulatory framework for permitting of exploration of potential CO_2 storage sites, the actual storage operations and post-closure obligations. The Directive focuses on the storage part of the CCUS chain even though there are some provisions concerning capture and transport to facilitate the chain integration. The Directive gives criteria for selection and characterization of storage sites, and obtaining exploration and storage permits (procedure, conditions, content, requirements for the Commission to review permits, changes and withdrawal of permits). The Directive also discusses operation, closure and post-closure obligations including but not limited to CO_2 stream acceptance criteria, measurement, monitoring and verification (MMV), risk assessment and measures in case of leakage, liability and transfer of responsibility, financial security and financial mechanisms. An evaluation of the Directive was performed in 2015 to judge if a revision would be necessary (European Commission, 2015). This review highlights that there is a lack of practical experience using the directive, which makes a revision premature. However, this report gives some recommendations of the articles that could be revised as for example, strengthening Article 33 on the readiness of CO_2 capture on both power and industry and clarifying the financial security concepts. These two documents could be used as a basis for any country wanting to develop a regulation related to CO_2 storage.

Figure 3.4 CO_2 Storage Capacity Pyramid



Source: CO2CRC.

Box 3.4: Other Storage Options Potentially Relevant for Asian Countries

Basalt formations, because of their unique properties that can trap injected CO_2 in solid minerals, can effectively and permanently isolate CO_2 from the atmosphere. Basalt formations, however, have not been widely considered as a potential site for permanent CO_2 storage (King Abdullah Petroleum Studies and Research Centre 2011). The CarbFIx project in Iceland has developed this possibility.

Dissolving of CO_2 in the deep ocean (up to 3km deep) was considered in the 2005 IPCC Special Report. The IPCC report concluded *"It is not known whether the public will accept the deliberate storage of CO_2 in the ocean as part of a climate change mitigation strategy. Deep ocean storage could help reduce the impact of CO_2 emissions on surface ocean biology but at the expense of effects on deep-ocean biology."* The option of deep ocean storage has since been off the agenda.

However, a special case of very deep ocean storage in specific deep ocean trenches at depth in excess of 6km has been considered.[b] The environment at that depth is significantly different from the general ocean floor. The water is undersaturated in carbonate, and the liquid CO_2 would be 10% more dense than the overlying water and CO_2-hydrates would likely form retaining the CO_2 permanently in an enclosed basin. There are candidate deep ocean trenches within the Exclusive Economic Zones of Indonesia, Japan, The Philippines, and New Zealand.

The London Protocol has provisions for permitting new arrangements when adverse effects are shown to be absent. Trials to establish the feasibility and safety of deep ocean storage of CO_2 could be carried out in the Sunda trench off Indonesia, which is not a party to the London Protocol.

A CO_2 delivery system to access deep ocean trenches has been considered in a subsequent report.[c] The storage capacity is effectively unlimited. This option is not relevant for CCUS readiness in the near term but should be considered as geological storage options become limited.

[a] IPCC. 2005. *IPCC Special Report, Carbon Dioxide Capture and Storage, Chapter 6 Ocean storage.* IPCC.
[b] Goldthorpe, S. 2017. "Potential for very deep ocean storage of CO2 without ocean acidification: A discussion paper." *Energy Procedia* (Elsevier).
[c] Goldthorpe, S. 2018. "Very Deep Ocean Storage of CO2 - Further Considerations." *GHGT-14.* Melbourne.

3.6.1 Storage Options for Carbon Dioxide in Asia

Table 3.3 shows an estimate of geological CO_2 storage capacity in Asia. Not all countries have executed a full storage capacity analysis, making these numbers rough estimates. The current storage capacity estimate for China is 1,573 Gt of CO_2 (Sun et al. 2017). Globally, only Brazil at 2,030 Gt and the USA at 2,367–21,200 Gt have larger estimated CO_2 storage capacity than China.

Table 3.3 Estimated Geological Storage Capacity for Countries in Asia

Country	Estimated storage capacity ($GtCO_2$)	Storage required by 2060[a]
China	up to 1573	37
India	47-143	19
Bangladesh	20	
Japan	146	
Korea	100	
Pakistan	32	
Sri Lanka	6	
Philippines	23	ASEAN countries
Indonesia	1.4-2	
Malaysia	28	9
Thailand	10	
Vietnam	12	

ASEAN = Association of Southeast Asian Nations, $GtCO_2$ = gigatons of CO_2.
[a] Based on IEA Energy Technology Perspectives 2017.
Sources: Consoli, C. P., and N. Wildgust. 2017. Current Status of Global Storage Resources. *Energy Procedia* vol. 114, no. November 2016, pp. 4623–4628; IEA. 2017. *Energy Technology Perspectives 2017*.

It is important that Asian countries confirm their CO_2 storage capacity through launching the appropriate actions. Although Table 3.3 suggests ample storage availability in the medium term, Figure 3.4 suggests that some of the capacity estimates might reduce significantly with further assessment.

3.6.2 Carbon Dioxide Storage-readiness

From an environmental point of view, capture without storage is pointless, and readiness for storage, facilitated by transport, matters profoundly (Markusson 2008). A report prepared for GCCSI provides the following conditions for storage readiness (ICF2010):

1) Identification of one or more storage sites technically capable of, and commercially accessible for, geological storage of full volumes of captured CO_2 at an acceptable cost;
2) Adequate capacity, injectivity, and storage integrity at the storage site(s);
3) Conflicting surface and subsurface land use identified and/or resolved;
4) All required environmental, safety and other approvals have been identified;
5) Public awareness, engagement activities related to potential future storage performed;
6) Sources for equipment, materials, and services for future injection and storage operations identified; and,
7) Storage Readiness is maintained or improved over time, as documented in reports and records.

In the development timeline of a CO_2 storage site, it means that the screening step should be performed to be CCUS-Ready. This step includes, but is not limited doing static capacity calculations, carrying out 3D simulations to estimate the injectivity, providing evidence of long-term containment, making sure that there will not be any competing activity on the site.

Depending on the formation considered for CO_2 storage, CO_2 emitters must be aware that between a site being identified for CO_2 storage and CO_2 injection commencing there can be a 10-year period. It is thus important for governments to take the lead in characterizing the storage potential of their respective country in order to support industries in carrying out CCUS-ready studies.

Box 3.5: Utilization of Carbon Dioxide as Means to Accelerate Carbon Capture, Utilization and Storage Implementation

The primary objective of carbon capture, utilization and storage (CCUS) is to reduce carbon dioxide (CO_2) emissions to the atmosphere, thereby contributing to addressing climate change. However, consideration of the captured CO_2 as a commodity to be utilized rather than a waste material to be disposed of is very attractive, both philosophically and commercially. Most current and planned CCUS projects involve utilization of the CO_2 in enhanced oil recovery (EOR) projects and are known as CCUS schemes. CCUS is important in providing a platform for the development of CO_2 capture and transport technologies. However, in considering CCUS schemes, care must be taken not to lose sight of the primary objective of addressing climate change.

CO_2 is a useful commodity in the food and beverage industry for the production of carbonated drinks and the manufacture of dry ice (solid CO_2) for temporary refrigeration applications. However, in these duties, the CO_2 is released to the atmosphere as soon as it has served its purpose, so the period of locking up the CO_2 is very short. Chemical and biological conversion of CO_2 into useful commodities, such as petrochemicals, algae, fuels, cement products, is extensively researched and promoted, but again the size of the market is small, and depending on the conversion, it could be a short-term storage solution dependent on renewable energy sources.

Enhanced oil recovery is by far the largest potential market for CO_2 as a commodity. When CO_2 is injected into a depleted oil field it improves the fluidity of residual hydrocarbons and enables oil that was otherwise unrecoverable to be produced. Some of the injected CO_2 would be produced with the recovered oil, but that CO_2 is separated and reinjected for EOR to reduce the amount of CO_2 that the oil field operator needs to purchase. There is a net consumption of CO_2, which remains underground after the EOR operation, so there is net sequestration of CO_2. China has carried out demonstration projects for injecting CO_2 for EOR. Depending on how the operation is done, CO_2 storage could be optimized.

Enhanced gas recovery (EGR) with CO_2 from hydrocarbon-bearing geological formations, in particular coal seams, is a potential technique for both natural gas production and degassing coal resources prior to mining. This is based on the preferential adsorption of CO_2 molecules on coal particles in place of adsorbed methane, known as Enhanced Coal-Bed Methane production.

Monitoring, reporting and verification plans should be in place for EOR and EGR operations.

Projects with a utilization component are not ideal for a CCUS-ready plan because they would rely on the market being available at some unknown future time. An advantage of utilization projects is that they could facilitate the development of some infrastructure that might be shared with future storage projects. Another advantage of is that CO_2 utilization schemes can provide economic assistance for early movers to help build knowledge and capacity in the CCUS technologies.

[a] Zhang, X., J. L. Fan, and Y. M. Wei. 2013. "Technology roadmap study on carbon capture, utilization and storage in China." *Energy Policy*, vol. 59, pp. 536–550.

Box 3.6: Scope for Carbon Dioxide-Enhanced Oil Recovery in China

The use of carbon dioxide (CO_2) for enhanced oil recovery (EOR) in North America is providing short-term opportunities for demonstrating carbon capture, utilization and storage (CCUS) technology. The revenue from sales of CO_2 to oil producers contributes to the costs of CO_2 capture. Since EOR is, by far, the largest potential commercial use for CO_2, it is the primary mode of CCUS.

Outside of North America, the scope and economics of CO_2-EOR is less well understood. A report by King Abdullah Petroleum Studies and Research Centre (KAPSARC) addresses those issue using bottom-up oil field data from 35,000 oil and gas fields.[a]

The KAPSARC report presents the estimated technical potential for CO_2/EOR storage on a country by country basis. The economically feasible scope of CO_2/EOR was then determined based on source-sink matching, with a limit of 500 km pipeline transport and the following key assumptions:

- CO_2 would *be accommodated at a net rate of 0.6 tonnes per barrel of extra oil produced;*
- *The oil companies would initially pay up to $10 per tonne for CO_2 in the short term;*
- *Later the oil companies would charge up to $50 per tonne of CO_2 accommodated; and*
- *The market price of oil wou*ld be $50 per barrel.

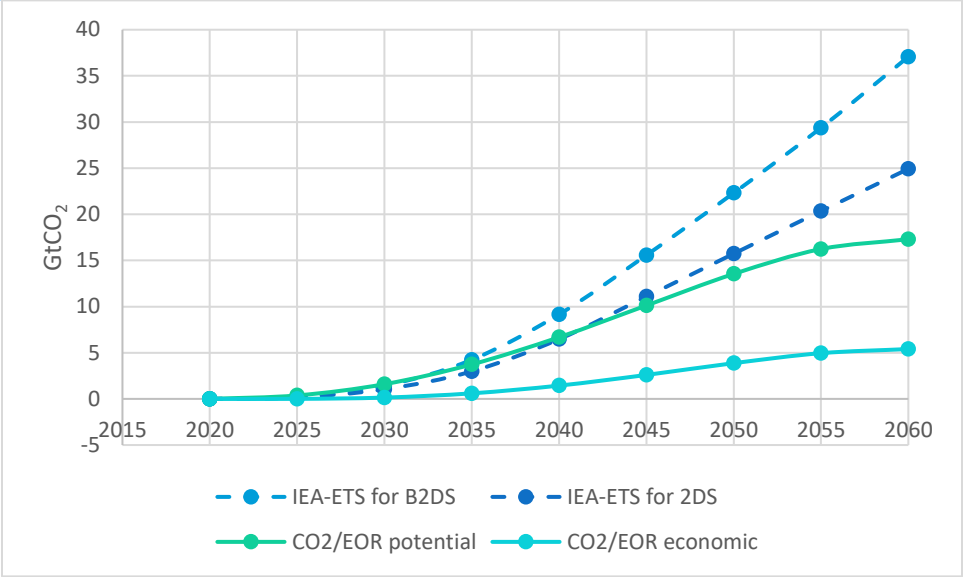
This economic analysis assumes that the most commercially attractive source-sink combinations are developed first until the demand is met and the supply is switched to the next most attractive CO_2/EOR project. The technical potential and the economically feasible scopes for CO_2/EOR are summarised in the following table.

$GtCO_2$ of CO_2/EOR potential and scope outside of North America

Country/Region	Technical potential	Feasible scope in economic analysis
China	17	5.4
Indonesia	3	1.7
India	1	0.7
Middle East	85	11.8
Former USSR	58	13.2
Europe, Africa and South America	19	7.2
Total excluding North America	183 $GtCO_2$	40$GtCO_2$

CO_2 = carbon dioxide, EOR = enhanced oil recovery, $GtCO_2$ = gigatonnes of carbon dioxide.
Source: King Abdullah Petroleum Studies and Research Centre. 2018. "Enhanced Oil Recovery and CO_2 storage Potential outside North America: An Economic Assessment."

Cumulative Potential EOR/CO_2 Scope in China vs Demand



B2DS = below 2 degrees scenario, CO_2 = carbon dioxide, EOR = enhanced oil recovery, $GtCO_2$ = gigatonnes of carbon dioxide, IEA-ETS = International Energy Agency-Energy Technology Scenario, 2DS = 2 degrees scenario.

This figure shows the likely cumulative technical potential (17 $GtCO_2$) and economic scope (5.4 $GtCO_2$) of CO_2/EOR in China distributed over 40 years to 2060. In contrast, the need for CO_2 storage in China, as identified in the IEA Energy Technology Scenarios model, are shown for the 2°C (2DS) and the <2°C (B2DS) scenarios over the same period. This comparison shows that the theoretical CO_2/EOR capacity in China estimated by KAPSARC might be sufficient to meet the demand for the 2DS scenario until 2040. However, the economically feasible scope for CO_2/EOR estimated in the KAPSARC economic analysis would only supply about 15% of the CO_2 storage required for the B2DS scenario by 2060, and none beyond then.

Over time, a transition would occur from oil field operators being purchasers of CO_2 for EOR to providing CO_2 accommodation services. In that medium-term scenario, the net reduction in fossil carbon addition to the atmosphere would be an important consideration. In the long-term CO_2/EOR potential would become exhausted and alternative CO_2 storage options would need to meet CO_2 emission mitigation objectives.

[a] King Abdullah Petroleum Studies and Research Centre. 2018. "Enhanced Oil Recovery and CO_2 storage Potential outside North America: An Economic Assessment." King Abdullah Petroleum Studies and Research Centre.

Chapter 4 **Power Generation Sector**

4.1 Introduction to the Power Generation Sector

The traditional focus of CCUS research and development since the 1980s has been the capture of CO_2 from baseload coal-fired power plants because they are large stationary continuous point sources of CO_2 discharged into the atmosphere. Such coal-fired power plants generally present lower-cost opportunities for CCUS in terms of cost per tonne of net CO_2 emission avoided than other schemes, apart from those where CO_2 separation is a part of the host process.

Furthermore, coal-fired power plants have become firmly identified in the public perception as the principal source of CO_2 emissions contributing to climate change, resulting in a strong push at the policy level for some countries to avoid building new coal-fired power plants without CO_2 control, provided alternative power generation options are sufficient to meet projected electricity demand.

This summary of CO_2 capture technologies, applicable to coal-fired power plants, presents a framework for a review of the scope for new power plants to be designated as capture-ready and for CCUS to be implemented early in the life of the power plant. The innovative landscape of technology developments aimed at reducing costs and improving energy efficiency. The IEA suggests a preference to focus CCUS on high-efficiency coal-fired power plants to minimize the compounding effect of the efficiency penalty of CO_2 capture. That preference may inhibit consideration of CCUS in locations where only low-quality lignite coal is available, or a hot climate mitigates against efficient power generation. Furthermore, it suggests a preference to replace older, less efficient power plants with new, more efficient power plant designs, into which CCUS can be integrated in due course.

Natural gas combined cycle (NGCC) power generation is inherently less CO_2 intensive than coal-fired power generation. Nevertheless, where natural gas is a principle source of baseload electricity supply, CCUS is considered for further reduction in CO_2 emissions.

4.2 Description of the Value Chain in the Power Generation Sector

The function of the power generation sector is to convert primary energy resources into a ubiquitous transportable form of high-value energy services, which is electricity. Unlike physical commodities, electricity cannot be readily stored but must be generated to meet the instantaneous demand of consumers. Electricity transmission grids provide that means of linking multiple power generation sources to a myriad of electricity consumers.

To ensure the security of supply, the available generation capacity must exceed the maximum instantaneous demand. The controller of an electricity grid is then responsible for despatching (i.e. instructing to operate) available power generation facilities to ensure that the instantaneous demand is met. The controller's decisions are based on a merit order of the available generators. In a competitive electricity market, the merit order depends primarily on the price of a generation that a power generator bids into the system. However, the reliability and the need to run at baseload (i.e. to operate continuously) are also factors considered by the grid controller in despatching power plants. Apart from the cost of

generation, the inclusion of CO_2 emissions in the controllers' criteria presents the opportunity to promote CCUS.

Low-cost coal-fired power stations are typically placed high on the merit order so that they are operated at baseload. They are not suited to rapid ramping output up and down. Hydroelectric and open-cycle gas-turbine power plants are well suited to load following and tend to be despatched to meet the daily variation in demand. Wind generation and photovoltaic generation have very low marginal operating costs and therefore may be allowed unconstrained access to the distribution grid although their output can be unpredictable. That is not a problem whilst the renewables are a minor contributor. However, all power plants must operate within a dynamic demand-led system.

In this free market context, the potential implementation of CCUS on a power plant supplying an electricity grid is problematic. If the cost of CCUS is simply added to the marginal cost of power generation, then the power plant would drop down the merit order relative to other plants without CCUS and accordingly it would not be routinely dispatched. To operate at baseload, which is highly desirable for the CO_2 capture plant, the price bid into the grid system in a free electricity market must be comparable with other power plants without CCUS. These issues are discussed in Section 1.7.

4.3 Carbon Dioxide Emissions from the Power Generation Sector

Coal-fired power plants are by far the largest potential sources of CO_2 that are candidates for the application of CCUS. Conventional state-of-the-art power plants burn pulverized coal (PC) in a supercritical steam raising boiler and generate electricity in a series of steam turbines in a sophisticated steam cycle. Individual PC power plant units typically have an output of about 660 MW of electricity.

Natural gas combined cycle (NGCC) power plants are the other major source of CO_2 emissions in the power generation sector. NGCC power plants have half of the greenhouse gas intensity of PC power plants, but CCUS is considered for further reduction in emissions. NGCC power plants use gas turbines that have a high excess air level, so the products of combustion are diluted in comparison with a PC power plant flue gas. NGCC power plants typically have an output of about 400 MW of electricity.

Large coal or gas power plants typically comprise multiple units. The products of combustion from a single unit are single flue gas streams with typical properties shown in Table 4.1.

Table 4.1 Flue Gas Properties of Typical Modern Power Plant Units

Fuel	Sub-bituminous coal	Pipeline Natural gas
Technology	PC with supercritical cycle	NGCC
Electricity output per unit	660 MW	400 MW
Nominal efficiency (hhv)	43%	50%
Excess air in the combustor	20%	200%
	Flue gas properties	
Volume flow	1.6 e^6 Nm^3/hr (drybasis)	1.9 e^6 Nm^3/hr (drybasis)
Temperature from HRSG	150°C	100°C
Pressure	Ambient	Ambient

CO_2 mass flow	476 tonnes per hour 720 kg CO_2/MWh	142 tonnes per hour 355 kg CO_2/MWh
CO_2 vol% $_{drybasis}$	15.4%	3.9%
O_2 vol% $_{drybasis}$	3.6%	14.4%
N_2 vol% $_{drybasis}$	80.9%	81.7%

CO_2 = carbon dioxide, hhv = higher heating value, HRSG = heat recovery steam generator, MW = megawatt, MWh = megawatt-hour, N_2 = nitrogen, NGCC = natural gas combined cycle, Nm^3/hr = normal cubic meter per hour, O_2 = oxygen, PC = pulverized coal, vol = volume.

The concentrations of SO_2, NO_x and particulates in these flue gases depend on the local environmental control limits. The impact of these contaminants on CO_2 capture is discussed in Section 4.4.2.

4.4 Carbon Dioxide Capture Technologies in the Power Generation Sector

Post-combustion capture, as described in Chapter 2, is the proven benchmark CO_2 capture technology for power generation. Because this is an "end-of-pipe" technology, it is amenable to retrofitting to a power plant and is therefore suitable as the basis for a capture-ready plan for a PC power plant or an NGCC power plant. Boxes 4.1 and 4.2 present commercially proven mid-sized scale post-combustion CO_2 capture technologies with chemical absorption from power generation at Boundary Dam and Petra Nova in North America. Box 4.3 illustrates a post-combustion capture at an advance stage of evaluation at Shand power plant in Canada. A case study examining the feasibility of adding CCUS to an existing NGCC power plant at Bibiyani, Hobiganj, Bangladesh is presented in Appendix A.

Box 4.1: Boundary Dam CCUS Project

The SaskPower Boundary Dam CCUS project is the world's first coal-fired power plant with the complete CCUS process full-chain at a commercial scale. The CCUS process is connected to Unit 3 of the four existing power generation units at Boundary Dam (BD3). The CCUS project was commissioned in October 2014. It has the capacity to provide up to 1 Mtpa of CO_2 for enhanced oil recovery.



Photo Credit to International CCS Knowledge Centre. https://ccsknowledge.com/bd3-ccs-facility.

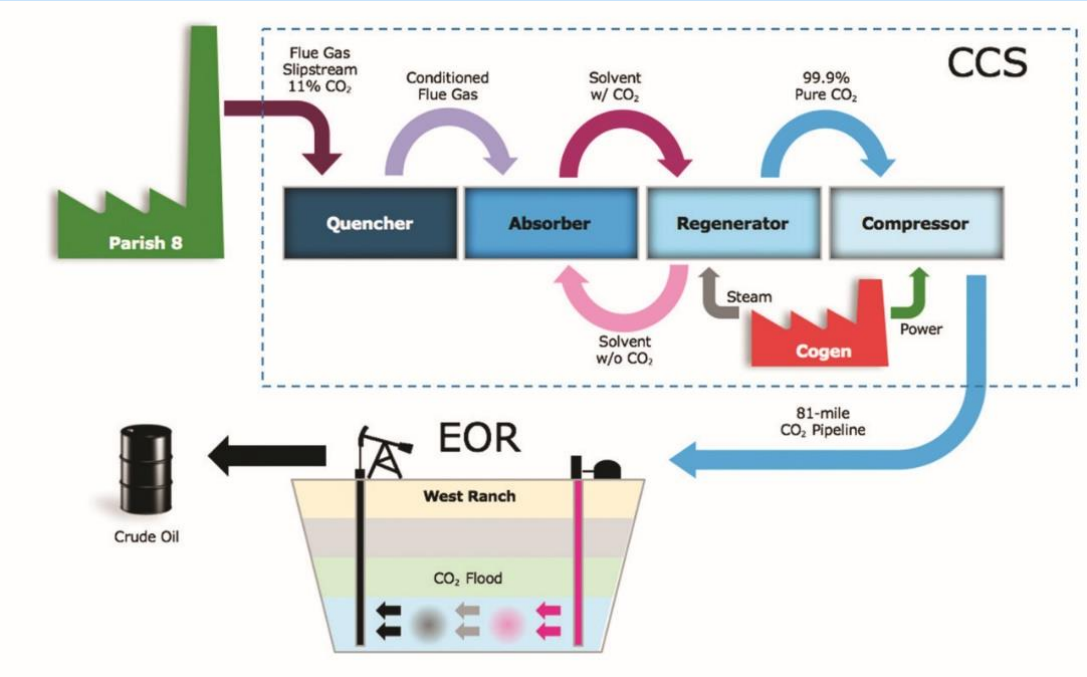
The Canadian Government enacted regulations in 2012, setting a CO_2 emission limit of 420 tonnes of CO_2 per GWh of power generated by new power plants or plants more than 50 years old. BD3 was constructed in 1970, so under the new Canadian Environmental Protection Act (CEPA) regulations, it was required to close by 2020 or to have a CCUS retrofit scheme designed by 2020 and operating by 2024. SaskPower decided to retrofit BD3 with CCUS prior to the CEPA regulation being enacted to gain experience with CO_2 capture technology, to upgrade the boiler and turbines of BD3 and to produce saleable by-products of CO_2, fly ash and sulphuric acid.

The total capital cost of Boundary Dam Unit 3 retrofit, sulphur recovery and CO_2 capture plant was approximately US$1.4 billion, which was in part supported by the Canadian Federal Government. The BD3 plant is the first-of-a-kind at commercial scale, with duplication of key process components. It is estimated that, based on the learning from BD3, and other plants, the capital cost of an "n-th" CO_2 Capture plant would be substantially lower than this first-of-a-kind CO_2 capture plant.

Source: International CCS Knowledge Center. https://ccsknowledge.com/bd3-ccs-facility.

Box 4.2: The Petra Nova CCUS Project

The Petra Nova Carbon Capture project in Texas is based on post-combustion capture of 1.4 Mtpa of CO_2 for use in EOR. The Petra Nova CCUS retrofit cost was reported to be $1 billion. To meet the CO_2 demand, 90% of the CO_2 is captured from a 37% slipstream from one power plant unit, i.e. about 7% of the total WA Parish power stationCO_2 output.



Sources: Sonal Patel, "Capturing Carbon and Seizing Innovation: Petra Nova Is POWER's Plant of the Year," *Power,* August 1, 2017, https://www.powermag.com/capturing-carbon-and-seizing-innovation-petra-nova-is-powers-plant-of-the-year/; NRG Energy.

The slipstream is sufficiently low in contaminants to only require a water wash before contacting with the KS-1 amine CO_2 absorbent in MHI's proprietary KM-CDR process. A feature of the CO_2 separation process at Petra Nova is the use of a modular rectangular absorber tower system, which facilitates scale-up. Electricity for pumps and CO_2 compression and steam for regenerating CO_2 from the amine solvent impose a substantial energy penalty on the host power generation plant.

The supply of CO_2 from Petra Nova to the local West Ranch oil field enables crude oil production to be increased from 500 barrels per day to 15,000 barrels per day. CO_2 produced with the oil is separated and reused for EOR, so the net CO_2 purchased remains in the oil field. In the first ten months, the plant delivered more than 1 million tons of captured CO_2, thus successfully demonstrating large scale commercial CCUS. In this case, the amount of carbon in the produced oil was about 50% more than the carbon in the net stored CO_2.

The Petra Nova CCUS project is a private sector commercial operation producing CO_2 as a commodity. It is primarily funded by sales of CO_2 for EOR, rather than subsidies, and is not dependent on legislative drivers. The host WA Parish power plant can operate with or without the CCUS operation.

Box 4.3: The Shand Power Plant CCUS Readiness Study

The Shand power station burns lignite in a sub-critical single unit 305 MW power station, which is about 12 km from Boundary Dam. The International CCS Knowledge Centre has conducted a CO_2 capture feasibility study, based on learning from the first-of-a-kind BD3 project. The studied processes were CO_2 capture with MHI's KM CDRTM amine-based scrubbing, wet limestone FGD, power plant integration and heat balancing. The amount of CO_2 that could be captured would be 2 million tonnes per year. The estimated overall cost of the CO_2 capture implementation would be US$45/tonne of CO_2 captured.

The findings of the Shand power plant study compared with the Boundary Dam operating plant was that:

- The power plant efficiency penalty would be halved;
- The steam requirements would be increased by 25%;
- The electricity requirements for capture would be reduced by 20%
- The power station modification cost would be greatly reduced;
- The capital cost of the CO2 capture equipment would be reduced by 70%; and
- The cost of electricity lost would be increased by 15%.

Source: Jacobs. 2018. "Shand Coal-Fired Power Plant – Integrating a post-combustion CO2capture process" presented during GHGT-14 conference.

Smaller conventional power plants comprising a steam raising boiler and an integrated steam cycle are well suited to post-combustion CO_2 capture. The combustor flue gas is cooled by steam raising and boiler feed water heating to a low temperature, which suits the subsequent flue gas cleaning processes of SO_2 removal and CO_2 capture. In that context, CO_2 removal can be considered as an additional environmental clean-up operation complementing the removal of particulates, NOx and SO_2 to meet environmental standards for flue gases discharged to the atmosphere.

The application of post-combustion CO_2 capture to a steam turbine power plant is independent of the boiler fuel used. Apart from coal, mid-sized steam turbine power plant might be fueled with heavy fuel oil, natural gas, biomass, or combustible waste materials, according to availability.

The energy requirements for post-combustion capture are low-pressure steam and electricity, which are both readily available from a steam turbine power plant. However, integration of the steam requirement with the host power station is not essential. For example, in the case of the Petra Nova plant, described in Box 4.2, the energy requirements for CO_2 capture are met by a facility that is additional to the host power plant.

Making a mid-sized load-following steam turbine power station (e.g. 300 MW) capture-ready would be essentially the same as making a large power plant ready for post-combustion capture. However, mid-sized power plants tend to be operated in a load-following capacity (e.g. operated daytime only). That mode of operation would make CCUS difficult to operate. Notwithstanding that concern, the Shand project development in Canada is being designed to accommodate flexible operation between 70% and 100% of full load.

Other CO_2 capture schemes that can be integrated with power generation are pre-combustion capture and oxy-fuel combustion and variants on these two approaches. Box 4.4 provides a brief description of a

CCUS plant based on pre-combustion capture from an integrated gasification combined cycle (IGCC) power plant developed at Kemper County, Mississippi, USA.

Box 4.4: Kemper County Integrated Gasification Combined Cycle Power Plant with CCUS

MIT Technology Review in 2017 reported the coal-fired power plant in Kemper County Mississippi power plant with pre-combustion capture of 65% of the CO_2 for EOR, was to have been the biggest proof of concept yet for Integrated gasification combined cycle (IGCC) but has failed to deliver on its promise. Its carbon capture technique has been declared too costly and problematic.

With project costing US$7.5 billion ($4 billion over its planned budget), and the CO_2 capture scheme three years behind schedule, plant's owner, Southern Company, stopped its attempts to get it working as designed and switched to natural gas for power generation without CO_2 capture.

The plant was supposed to gasify soft brown lignite coal to create a fuel gas that, after CO_2 capture, would emit similar amounts of CO_2 to natural gas when burned (Condliffe 2017). The problems with the Kemper County IGCC/CCUS plant have related mostly to the novel coal gasification equipment, rather than the CO_2 separation equipment. However, the cancellation of this project has set back the evolution of pre-combustion capture CCUS as applied to coal plants.

It had been hoped that the theoretically lower energy penalty of CO_2 capture in IGCC compared with CO_2 capture from a combustion plant flue gas, would encourage the uptake of IGCC technology. However, that outcome failed to eventuate.

The high extent of integration of power generation with CO_2 capture means that pre-combustion and oxy-fuel technologies and other emerging power generation technologies are only suitable for new build power plants and are not contenders for inclusion in a capture-ready plan, which would require the power plant to be economically viable both with and without CO_2 capture.

Other smaller-scale fossil fuel power plants include open-cycle gas turbines and diesel engine generators. These less efficient power plant technologies are used intermittently and have a high stack gas temperature, so they are not readily amenable to retrofitting CO_2 capture.

Chapter 2 describes the conventional post-combustion capture from cooled, ambient pressure flue gas with amines. That capture technology can be applied to the flue gas from any fossil fuel combustion process. In the context of power generation from coal, additional flue gas desulphurization would be required, and the low-grade heat source would be low-pressure steam (e.g. 0.5 MPa) extracted from the power generation steam cycle.

4.4.1 Space requirement in power plant layout

The principal feature of a capture-ready power plant is a layout that accommodates the future installation of CO_2 capture equipment. Boxes 4.1 and 4.2 illustrate the scale of additional equipment installed for the CO_2 capture facilities on the host power plant sites at Boundary Dam and Petra Nova.

Estimates of space requirements are six hectares plus laydown area for post-combustion capture on a 2000 MW power plant (World Bank 2015) and 3.75 hectares for a 500 MW power plant (Florin 2009), suggesting a guideline land requirement of about 30-75 m^2/MW or 0.5 to 1.5 hectares per million tonnes per year of CO_2 captured.

In the layout of a new capture-ready power plant, the provision would need to be made for a rational low-pressure flue gas flow path from the combustion and heat recovery, through initial flue gas cleaning, supplementary gas cleaning and cooling, CO_2 scrubbing, residual gas washing to the discharge stack.

In view of the large size of the scrubber and regenerator vessels and other CO_2 capture equipment, a large area of land might also be required for temporary use as a laydown area during the retrofitting of the CO_2 capture facility. In addition, the temporary availability of an access corridor for the delivery of large vessels to the site may be required. In the Petra Nova CCUS plant (as shown in Box 4.2), a modular structure to the CO_2 scrubbing facility was developed. That on-site assembly method reduced the logistical problems of delivering large vessels.

The purchase and designation of land to accommodate a future CO_2 capture facility may be a significant initial capital cost. Whilst the main capital investment in CO_2 capture would be incurred at the time of retrofitting, the purchase of land, or the arrangement of an option to purchase the land, would be an up-front cost at the time of designation of the plant as capture-ready.

For retrofitting CO_2 capture to an existing power plant, the availability of suitable land or access for delivery of equipment might be an insurmountable barrier to making the plant capture-ready, particularly if the existing plant is in an urban environment. Also, physical access to the flue gas duct or to the steam extraction duct may be compromised.

4.4.2 Flue Gas Cleaning Requirement

Chemical CO_2 capture from a flue gas requires the feed gas to have a low level of contaminants to minimize degradation of the recycled amine solvent. The principal contaminants of concern in a coal-fired power plant are SO_2, NOx and particulates. State-of-the-art coal-fired power plants typically include electrostatic precipitation of particulate material and selective catalytic reduction (SCR) of NOx in the hot gas train prior to heat recovery. Flue gas desulphurisation is typically a low-temperature wet process located after heat recovery.

The feed gas to amine scrubbing should contain no particulate material, less than 10 ppmv (30 mg/Nm^3) SO_2 and less than 24 ppmv (50 mg/Nm^3) NOx (World Bank 2015). Table 4.2 shows some new emission standards for coal-fired power plants for some countries. For most countries, these standards are inadequate to meet the feed gas criteria for amine scrubbing. However, the new tight emission standards listed for some jurisdictions in China (50 mg/Nm^3 for NOx and 35 mg/Nm^3 for SO_2) are close.

Table 4.2 Selected Countries' Emission Standards for Coal-fired Power Plants

Country	Time period	NOx, mg/Nm3		SO_2, mg/Nm3		PM mg/Nm^3	
		existing	new	existing	new	existing	new
Australia			800		200		80
China	hourly	100	50	200/50	35	30/20	10
Germany	daily	200	150	200	150	20	10
India	continuous	600/300	100	600/200	100	100/50	30
Indonesia		850	750	750	750	150	100
Japan		410	200		200	100	50
South Africa	continuous	1100	750	3500	500	100	50
Thailand		820	410	2002	515	180	80
USA	daily	135	95.3	185	136	18.5	12.3
EU	continuous	200	150	200	150	20	20

EU = European Union, mg/Nm^3 = milligrams per normal cubic meter, NOx = oxides of nitrogen, PM = particulate matter, SO_2 = sulfur dioxide, USA = United States of America.
Source: Sanjeev Paliwal. 2016. Environmental Regulations for Coal Based Thermal Power Plant. Clean Air Asia. Central Pollution Control Board. http://cleanairasia.org/wp-content/uploads/2016/09/06_Sanjeev-Paliwal_CPCB.pdf.

Construction of a capture-ready coal-fired power plant to meet these tight emission standards would benefit local air quality in an authority where air quality standards are less stringent.

In the case of natural gas-fired power plants, there are no particulate emissions. The SO_2 emission standards could be met by H_2S removal from the natural gas to less than 280 ppm prior to combustion. The NOx standard would need to be met using selective catalytic reduction.

4.4.3 Steam requirement

A benchmark energy requirement for the reboiler in the regeneration unit of a CO_2 capture plant is 3.2 GJ per tonne of CO_2 recovered (World Bank 2015). That energy can be supplied as 0.5 MPa steam drawn from the power plant steam cycle. In a typical power plant that would take about half of the total steam flow to the low-pressure steam turbine. However, extraction of steam from the steam turbine, with the corresponding loss of electricity production, would not be necessary if there is some other source of low-grade heat (at 120-150^oC) available.

For example, in the case of the Petra Nova plant, an existing 75 MW peaking gas turbine has been converted into a combined heat and power (CHP) plant to match the utility requirements for the CO_2 capture and liquefaction facility. That arrangement reduces the impact of retrofitting CCUS on the host coal-fired power plant.

4.4.4 Electricity Requirement

In addition to the low-grade heat requirement for CO_2 capture, there is also an electricity requirement for pumps and for compressing the CO_2 product. A benchmark electricity requirement is 140 kWh per tonne of CO_2 captured (World Bank 2015). That benchmark is based on the CO_2 product being compressed and liquefied to deliver a liquid CO_2 product at 11 MPa pressure. At that pressure, further pumping during transport of liquid CO_2 may not be required. It is estimated that if the CO_2 is transported by ship, an additional 16.5 kWh per tonne of CO_2 may be required.

The reduction in net output of electricity from the power plant due to retrofitting CCUS would have no immediate effect on the capture-ready power plant, but it is an important matter to consider when planning the criteria that would trigger the later implementation of CCUS.

4.4.5 Summary of Capture-Readiness Requirements

The principal capture readiness requirements are

- a plan for retrofitting the chosen CO_2 capture technology in the future;
- accommodation of that plan in the host power plant design;
- the layout of the host power plant to accommodate CO_2 capture;
- identification of the criteria that will trigger implementation; and
- the avoidance of barriers to implementation of CO_2 capture.

In addition, to be CCUS-ready, CO_2 storage or a CO_2 utilization application would need to be identified, with a feasible means of transporting the CO_2 to that location.

This review has identified some quantified technical guidelines that may assist in the design of a CO_2 capture plant, as listed in

Table 4.3. The cost of CO_2 capture would need to be determined by a case-specific design study.

Table 4.3 Capture-Ready Benchmarks for CO_2 Post-Combustion Capture Plant Design

	Reference benchmarks
Land allocation for CO_2 capture facilities and associated plant	0.5 to 1.5 hectares per million tonnes per year of CO_2 capture
Maximum NOx content of flue gas to avoid need for additional NOx removal	~50 mg/Nm^3 (24 ppmv)
Maximum SO_2 content of flue gas to avoid need for additional desulphurisation	~30 mg/Nm^3 (10 ppmv)
Maximum particulate content in flue gas to avoid the need for additional dedusting	~10 mg/Nm^3 (probably removed in water wash and cooling of feed gas)
Additional energy requirement as low-pressure steam demand for amine regeneration	~3.2 GJ/tonne of CO_2 for coal-fired flue gas scrubbing ~2.5 GJ/tonne CO_2 with advanced amine scrubbing systems ~3.5 – 4 GJ/tonne of CO_2 for NGCC flue gas scrubbing
Electricity demand for scrubbing plant and CO_2 compression and liquefaction	~140 kWh/tonne of CO_2 plus 16.5 kWh/tonne of CO_2 if transported by ship
Net process water requirement	Nil - due to condensation of water from flue gas
Additional cooling requirement	About equal to the additional energy requirement

CO_2 = carbon dioxide, GJ = gigajoules, kWh = kilowatt-hour, mg/Nm^3 = milligrams per normal cubic meter, NGCC = natural gas combined cycle, NOx = oxides of nitrogen, ppmv = parts per million by volume, SO_2 = sulphur dioxide.
Source: World Bank (2015).

Condensation of water vapor from the flue gas means that there is typically no net process water requirement in an amine post-combustion capture scheme with an integrated water recycling system. However, the increase in cooling requirement may increase the demand for cooling water.

4.5 Capture-ready Prospects in the Power Generation Sector

Post-combustion capture with chemical absorption has been advanced to the commercial-scale with all components of the technology train proven in the context of providing CO_2 for EOR. The principle remaining barriers to the widespread implementation of CCUS are economical and regulatory. It would be prudent for new coal and gas-fired power plants to be designed ready for retrofitting with post-combustion capture when those necessary conditions eventuate.

In the current global economic and regulatory environment, the only prospect of CO_2 capture being applied to fossil fuel power stations is where there is a commodity market for the captured CO_2 for EOR. CCUS is a valuable enabling step in the evolution of widespread CCUS because it provides the opportunity for demonstration of CO_2 capture processes, to counter the claim that CCUS is an unproven technology. CCUS also provides a vital capacity-building opportunity and an essential platform for CO_2 capture, transport, and injection technology development.

However, the scale of CO_2 capture from power generation that will be required if the generation of electricity from coal and natural gas is to continue in a carbon-constrained future greatly exceeds the demand for CO_2 for EOR. Therefore, the way forward for the application of CO_2 capture in the electric power sector is to consider a "post-utilization" scenario in which the captured CO_2 is transported and stored at a cost without any associated revenue. That scenario could eventuate either when national regulatory regimes are put in place to enable countries to meet international CO_2 emission control obligations, or when the internationally traded price of CO_2 emission credits rises to the point where the purchase of credits to offset the CO_2 emissions from a coal or gas power plant makes CCUS the economically preferable alternative.

4.6 Economic Considerations for Carbon Dioxide Capture in the Power Generation Sector

The principle capital expenditure for the application of CO_2 capture to a capture-ready power plant would occur at the time of future retrofitting. The capital investment required will depend on case-specific factors. However, the additional investment required for CO_2 capture is typically estimated to be 50% to 100% of the base cost of the power plant without CCUS.

There may be some up-front capital required to purchase land adjacent to the power plant that is to be designated as capture-ready or to purchase transport route easements or storage option rights. The potential sources of funding for investment in CCUS will depend on the regulatory and financial drivers that cause CO_2 capture to be implemented. Cost issues are discussed in more detail in Chapter 8.

4.7 Timeline for Carbon Capture, Utilization and Storage-readiness in the Power Generation Sector

The timing of the post-utilisation scenario becoming a reality is unknown, but it could occur within the lifetime of coal and gas power plants that are being planned and built now. Therefore, to future-proof those assets, to avoid them becoming stranded assets, it is prudent to design new power plants to be capture-ready and to review existing efficient power plants with a long life for the feasibility of being designated capture-ready.

As identified above, post-combustion capture is the only CO_2 capture configuration that is amenable to retrofitting to a power plant some years after the original commissioning of the power plant. The other CO_2 capture schemes involve a level of integration with the host power generation function that would be impractical for retrofitting. The other integrated CO_2 capture schemes that are being developed may well be found to be more efficient than post-combustion capture for new-build power plants, but not for retrofitting.

Chapter 5 Carbon Dioxide Capture Opportunities in the Iron and Steel Sector

5.1 Introduction to the Steel Sector

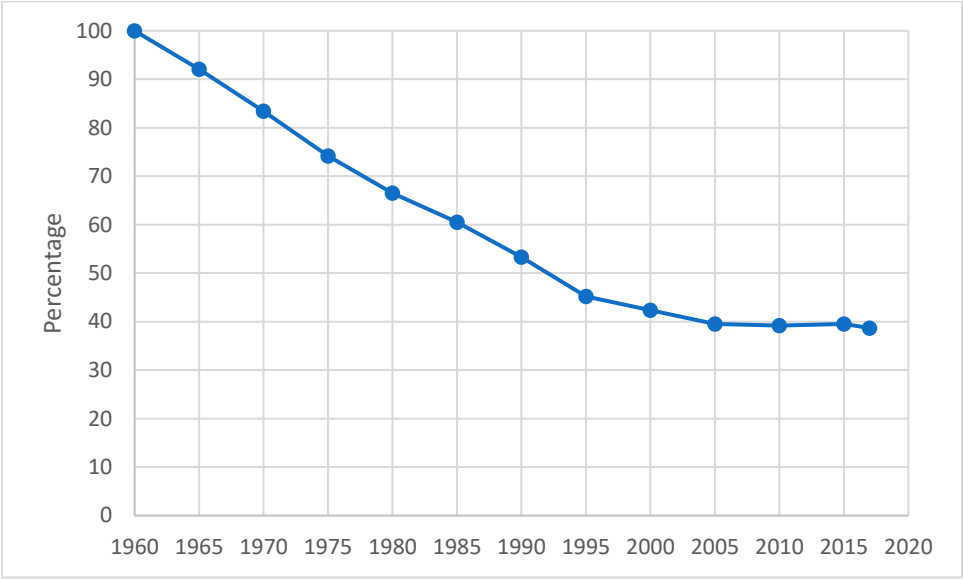
Steel has a lower production cost as compared to other material of its type. For example, the energy requirement for extracting iron from its ore is about 25% of what is needed for extracting aluminium from bauxite (Rankin 2012). Steel is environmentally friendly as it is recyclable and does not produce toxic runoff. Due to its universal and desirable properties, steel production is nearly 20 times higher than the production of all non-ferrous metals put together (The World Bank Group 2006). World crude steel production reached 1,808 million tonnes (Mt) in 2018 and is expected to increase by 1.5 times by 2050 (World Steel Association 2018a). In a carbon-constrained economy, the production of this quantity of steel is a challenge because steel production processes are energy and carbon-intensive.

The average energy intensity of steel making process is 20 GJ per tonne of crude steel, generating an average of 1.83 tonnes of CO_2 per tonne of steel produced (World Steel Association 2019a). The global energy consumption in steelmaking is estimated to be about 20% of the annual industrial energy requirements (Rankin 2012). The total CO_2 emission from the global steel industry is 7% to 9% of direct emissions from the global use of fossil fuel (World Steel Association 2019b). The steel industry is the biggest emitter of CO_2 outside fossil fuel power generation. Major components of low carbon economy such as wind energy, low carbon transport, sustainable infrastructure and recycling facilities depend on steel-based products. Therefore, it is essential to transform the steel industry to low carbon sector for the realization of a low carbon economy.

The steel industry provides both challenges and opportunities in reducing greenhouse gas emissions and making the industry sustainable. Implementation of energy management systems and improvement in energy efficiency has led to reduction of about 61% in energy required to produce a tonne of crude steel since 1960 as shown in Figure 5.1 (World Steel Association 2019b). Carbon intensity trends are closely related to energy intensity trends but are also dependent upon the fuel mix process modifications used by the iron and steel industry in each country. Energy efficiency measures in the steel industry are approaching saturation level with diminishing returns. Along with the use of other breakthrough technologies, such as hydrogen and biomass as reducing agent and electrolysis, CCS and CCU can contribute to reducing CO_2 emissions (World Steel Association 2019b). By 2060, up to 10 Gt of CO_2 can be captured cumulatively from the iron and steel sector (IEA 2019b).[19] Large-scale implementation of these breakthrough technologies would require a transformation of the global energy system (World Steel Association 2019b).

[19] With this amount, the relative contribution of CCUS to emissions reduction in the iron and steel sector is about 15% (IEA 2019b).

Figure 5.1 Indexed Global Energy Consumption per Tonne of Crude Steel Production

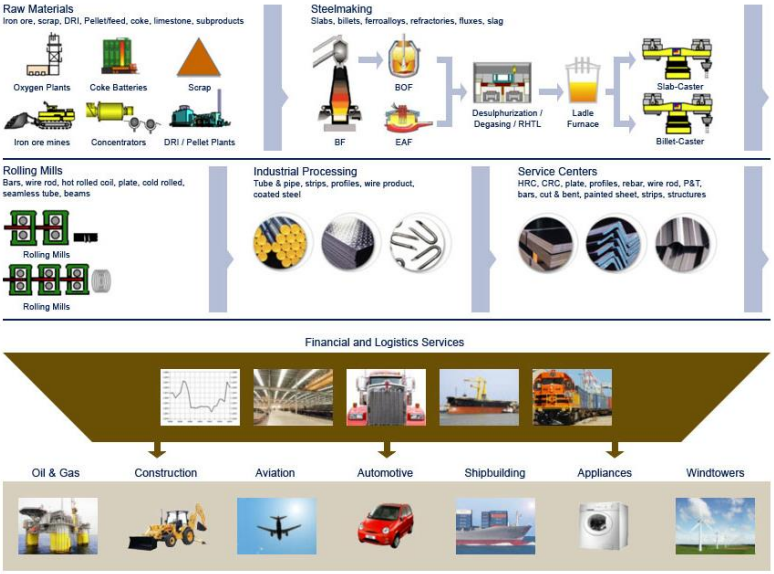


Source: Adapted from World Steel Association. 2019. Steel's Contribution to A Low Carbon Future. https://www.worldsteel.org/publications/position-papers/steel-s-contribution-to-a-low-carbon-future.html.

5.2 Description of the Value Chain in the Steel Sector

The value chain is defined as a chain of value-added activities in which products pass through the activities in a chain, gaining value at each stage (Porter 1980). Figure 5.2 shows a typical value chain for the iron and steel industry. A study of the value chain of United Kingdom's steel industry was conducted with particular interest in values of the main material categories of iron and steel iron ore, pig iron, crude steel, iron and steel products, scrap, as well as the cost (negative value) of waste disposal (Dahlstrom and Ekins). Figure 5.2 shows the values of steel products in the value chain. In Table 5.1, values are shown for the broad material categories used in the material flow analysis, unless data existed to allow a value breakdown where this was important.

Figure 5.2 Iron and Steel Value Chain



Source: C&F International. 2018. Retrieved from http://www.cnfinternational.com/valuechain.html.

Although this data is for the United Kingdom's steel industry, it provides valuable information on the relative value of the products in iron and steel value chain.

Table 5.1 Iron and Steel Values and Data Sources for United Kingdom

Principal category	Detail	Value (£/tonne) all data 2001
Crude steel	Carbon steel	170
Crude steel	Low alloy steel	470
Crude steel	High alloy steel	960
Crude steel		290
Crude steel	Imported	310
Iron ore	Imported	20
Pig iron	Domestic	60
Pig iron	Exported	510
Pig iron	Imported	180
Scrap	Home scrap	90
Scrap	Prompt scrap	90
Scrap	Old scrap	50
Scrap	Exported	80
Scrap	Imported	280
Steel products	Domestic	420
Steel products	Exported	420
Steel products	Imported	380
Waste disposal	Landfill	(-16) to (-12)

Source: Kristina Dahlstrom and Paul Ekins. 2006. "Combining economic and environmental dimensions: Value chain analysis of UK iron and steel flows." *Ecological Economics* 58. https://doi.org/10.1016/j.ecolecon.2005.07.024.

5.3 Carbon Dioxide Sources in the Steel Sector

CO_2 emission from an iron and steel plant can be divided into two categories: direct and indirect emission. Direct CO_2 emissions are due to fossil fuel and raw material used in the iron and steel making process. Fossil fuels include coal, fuel oil and steel plant waste gases used as a fuel; such as coke oven gas, blast furnace gas and convertor gas. Raw materials include iron ore, limestone, dolomite, and slag produced during the iron and steel making process. Direct emissions are also known as Scope 1 emissions (World Resources Institute 2016).

Indirect CO_2 emissions are caused by the processes external to iron and steel making processes. These are upstream emissions or credits related to procurement and delivery of electricity, steam and exported by-product gas considering the potential savings in electricity generation (World Steel Association). The total emissions from a steel plant is the sum of direct and indirect emissions adjusted for any carbon offset. Carbon offsets include offset from sales of any by-product and electricity generated from steel mill off gases. Indirect emissions are known as Scope 2 emissions, which are outside of the scope of this report.

5.3.1 Blast Furnace/Basic Oxygen Furnace Steel Process

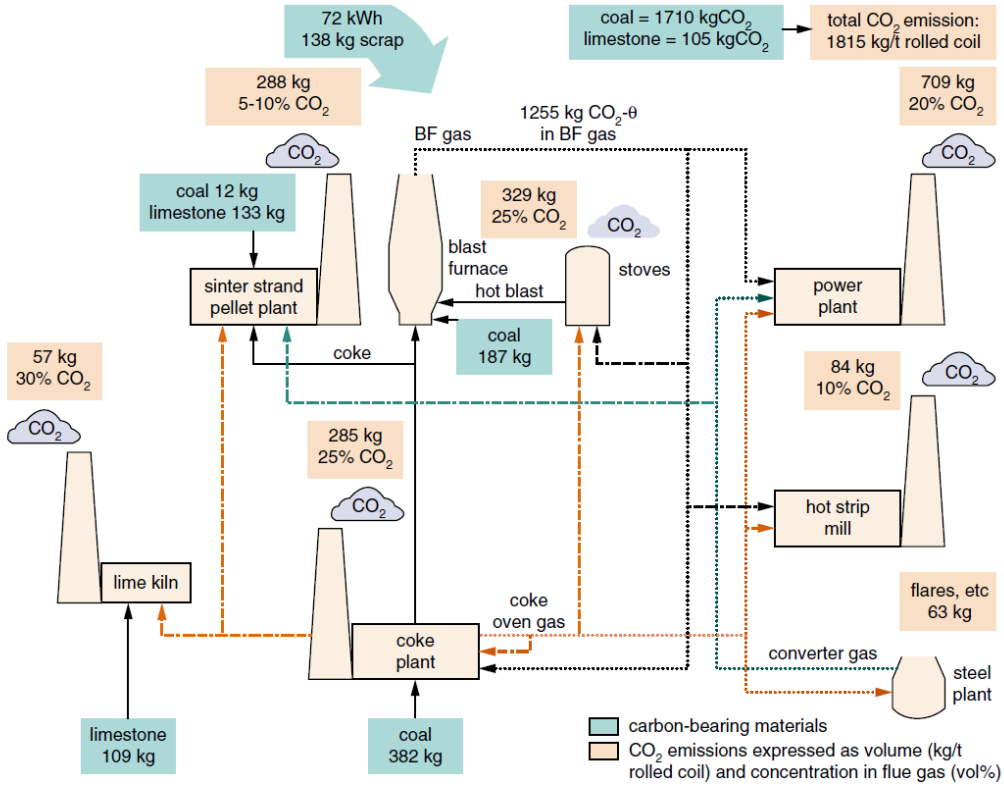
Steel production from blast furnace/basic oxygen furnace (BF/BOF) presents several opportunities for CO_2 capture. There are several CO_2 sources across a typical steel plant with a variety of conditions that will affect their suitability for CO_2 capture. A typical integrated BF/BOF process carbon balance with emissions points and amounts per metric ton of hot-rolled coil steel product is shown in Figure 5.4. 94% of the carbon originates from coal, and 6% originates from limestone. A small amount of carbon exits the steel making process as carbon in the steel products; up to 0.25% in mild steel and up to 2% in carbon steel.

Blast furnace off-gas (BFG) contains mostly carbon monoxide (CO) and CO_2 and is used as a fuel gas in the integrated steel plant, primarily in the power plant. Coke oven off-gas (COG) contains methane and burns at a higher temperature than BFG. COG is used as a fuel gas in several applications in an integrated steel plant. A third source of fuel gas in a steel plant is the off-gas from the converter, which is used as a supplementary fuel in the power plant. The fuel supplies to steel plant process units may be supplemented by natural gas, if it is available, which would reduce the CO_2 emission factor for the steel plant, compared with a plant that is supplied only with coal as the source of primary energy.

Table 5.2 lists the CO_2 emission sources presented in Figure 5.4. Also shown in Table 5.2 is comparative data from a later modelling study of an integrated steel plant.

Table 5.3 presents a compilation of gas compositions and contamination data for the principle CO_2 sources in an integrated steel plant. While these data have vast ranges of possible contamination levels, this compilation of data suggests that the sinter plant gas is not amenable to post-combustion CO_2 capture because of the low CO_2 content and the high levels of contaminants. However, combining the power plant flue gas (20%); with the blast furnace stoves flue gas (25%); the coke oven flue gas (25%); and the lime kiln flue gas (30%); could raise the CO_2 content of the CO_2 scrubber feed to 22.5%, which would be beneficial.

Figure 5.3 Typical Integrated Steel Mill Emissions and Carbon Balance



Source: Birat, J.P. 2010. "Steel Sectoral Report," in Global Technology Roadmap for CCS in Industry. United Nations Industrial Development Organization.

Table 5.2 Carbon Dioxide Emission Points from Modelled Integrated Blast Furnace and Basic Oxygen Furnace Steel Plants

Emission point	kg CO_2 per tonne steel	CO_2 conc.	Fraction of emissions	kg CO_2 per tonne steel	Fraction of emissions
	Data from Figure 4.4			IEAGHG 2013-004	
Power plant flue gas	709	20%	39%	982	47%
Blast furnace stoves	329	25%	18%	415	20%
Sinter plant stack	288	5-10%	16%	289	14%
Coke oven stack	285	25%	16%	191	9%
Hot strip mill stack	84	10%	5%	58	3%
Lime kiln stack	57	30%	3%	72	3%
Flares and minor users	63		3%	87	4%
Total	1815			2094	

kg CO_2 = kilograms of carbon dioxide, CO_2 = carbon dioxide, IEAGHG = IEA Greenhouse Gas R&D Programme.
Sources: Birat, J.P. 2010. "Steel Sectoral Report," in Global Technology Roadmap for CCS in Industry. United Nations Industrial Development Organization; IEAGHG. 2013. "Iron and Steel CCS Study (Techno-Economics of Integrated Steel Mill)."

Table 5.3 Carbon Dioxide Emissions and Stream Factors for Flue Gases from Blast Furnace/Basic Oxygen Furnace Process

Stream	CO_{2e} Emissions	CO_2 Concentration		Other contaminants			
	$kgCO_2/t$ crude steel	%vol		CO	SOx	NOx	Dust
Lime	57.0–72.0	19.3–19.4	g/t lime	200.0–4,460.0	80.0–900.0	336.0–1,783.0	16.0–298.0
Coke off gas	60.0–360.0	11.0–25.0	g/t coke	200.0–4,460.0	80.0–900.0	336.0–1,783.0	16.0–298.0
Sintering Gas	200.0–466.0	5.0–10.0	g/t sinter	8,783.0–37,000.0	220.0–973.0	302.0–1,031.0	41.0–560.0
Hot Blast Stove	240.0–415.0	25.0–28.5	g/t hot metal	1.6–4,336.0	1.6–231.0	6.0–173.0	0.4–18.0
Power Plant	709.0–982.0	9.9–26.4	mg/Nm^3	0.8–33.0	1.1–305.0	14.0–190.0	0.8–31.0

CO = carbon monoxide, CO_2 = carbon dioxide, CO_{2e} = carbon dioxide equivalent, g/t = grams per tonne, mg/Nm^3 = milligram per normal cubic meter, NOx = oxides of nitrogen, SOx = sulfur oxide.
Sources: Birat, J.P. 2010. "Steel Sectoral Report," in Global Technology Roadmap for CCS in Industry. United Nations Industrial Development Organization; IEAGHG. 2000. Greenhouse Gas Emissions from Industrial Sources - III Iron and Steel Production. IEAGHG. 2013. "Iron and Steel CCS Study (Techno-Economics of Integrated Steel Mill)"; Remus, and Monsonet. 2013. Best Available Techniques (BAT) Reference Document for Iron and Steel Production. European Commission Joint Research Centre; Toshiba Corporation. 2015. Applying carbon capture and storage to a Chinese steel plant. Global Carbon Capture and Storage Institute.

5.3.2 Electric Arc Furnace Route

The electric arc furnace (EAF) process for secondary steel production is used for converting recycled scrap steel into crude steel for further processing. Since the EAF process does not include processes for reducing iron ore to iron, the CO_2 emissions are much less than those of the BF/BOF process. One comparison reports for EAF plants the figure is 0.62 t CO_2/t crude steel (plus CO_2 from electricity generation); while for BF/BOF plants CO_2 intensity is 2.26 t CO_2/t crude steel (Reimink 2015).

The principal CO_2 emission associated with the EAF process is the indirect emission from electricity generation, which is usually external to the steel plant and is outside the scope of this report. Nevertheless, there are direct CO_2 emissions arising from the EAF process arising from carbon from the charge, carbon in scrap iron and first fusion pig iron, supplementary fuel, and carbon from the graphite electrodes, which are gradually consumed.

5.3.3 Direct Reduced Iron Electric Arc Furnace Route

Natural gas is predominantly used as a source of reducing agent in direct-reduction iron (DRI) making. Natural gas may contain CO_2. Methane is the primary component and the major source of the reducing gases of CO and H_2. The shaft furnace is the main source of CO_2 emission in the DRI process. From an emission viewpoint, various techniques of ironmaking in the DRI process cannot be compared since they use different feed and produce different products. Table 5.4 summarizes the CO_2 emissions for DRI and EAF route based on published works.

Table 5.4 Carbon Dioxide Sources and Conditions for Electric Arc Furnace and Direct Reduced Iron Processes

Stream	Electricity Consumption	CO_2 Emissions	CO_2 Concentration		Contaminants			
	kWh/t crude steel	kg/t crude steel	%vol		CO	SOx	NOx	Dust
EAF	330–370 Scrap 350–550 DRI	250–400	40	g/t liquid steel	740-3,900	24-130	120-240	1-780
DRI - NG	80–90	500–980		g/t DRI		20-2,400	48-1,500	44-300
DRI - Coal	70–100	1,461–1,700	2–18 (typ. 5–10)	mg/Nm^3		465-520	78	190
Pelletization	15–27.5	10–31		g/t pellets	10-40	18-250	120-510	20-130
Power Plant	-	170–800	DRI – 5-20 Scrap – Grid		Dependent on fuel source and steel mill energy recovery			

CO = carbon monoxide, CO_2 = carbon dioxide, DRI = direct reduced iron, EAF= electric arc furnace, g/t grams per tonne, kg/t = kilograms per tonne, kWh = kilowatt-hour, mg/Nm^3 = milligram per normal cubic meter, NG = natural gas, NOx = oxides of nitrogen, SOx = sulfur oxide, tDRI = tonnes direct reduced iron, typ. = typical, vol = volume.
Sources: Central Pollution Control Board (2007); IEA (2007); IEAGHG (2000); Seetharaman (2013); Wiley, Ho, et al (2011).

Electric arc furnaces take solid iron or scrap and melt the solid down as part of the conversion to steel. This is achieved partially through electrical currents and partially through the exothermic reactions and oxy-fuel firing of the associated carbon that takes place within the EAF. The electrical energy represents around 65% of the energy requirements for the EAF depending on the carbon content of the feed.

The possible feeds for an EAF are scrap steel and/or DRI produced from iron ore. The overall energy requirements for steel production are different depending on the feed. The use of DRI increases the energy requirements for the EAF due to the slag in the DRI. The overall energy requirements are further increased due to the need to process the iron ore raw material to DRI. The typical energy requirements for steel production through EAF are 9–12 GJ/t of crude steel (tCS) for a scrap feed compared to 18–30 GJ/tCS for a DRI feed, including pre-processing (IEAGHG 2013b). In comparison, the BF-BOF process uses 18–23 GJ/tCS (IEA 2007).

DRI production primarily uses either the Midrex process or the HyL process, which combined makeup 78% of total DRI production. Both processes reform natural gas (NG) into syngas (a mixture of H_2 and CO) for use as the reducing agent in iron production, but they differ in the reforming method, with Midrex using CO_2 reforming and HyL using steam reforming. Both processes require around 10.4 GJ of NG/tDRI produced (IEA 2007).

Despite 78% of DRI being produced using natural gas, India, the country that produces the most of total DRI, primarily uses coal-based DRI, in which coal and iron ore are pelletized or briquetted together and fed into a rotary kiln; typically the Stelco-Lurgi/Republic Steel-National Lead [SL/RN] process or a Rotary Hearth Furnace. The coal and ore mixture is heated, and the iron ore is reduced to iron and coal is oxidised to CO_2 and CO. The advantage of this process is that is allowing of the use of non-coking coal as a reductant to produce iron ore.

The use of coal-based rotary kilns significantly increases the CO_2 emission intensity of DRI production. CO_2 emissions from rotary kilns increased 1,461 $kgCO_2$/tDRI compared to 518–550 $kgCO_2$/tDRI for natural gas (NG) processes (Battle et al. 2013). Despite the high specific CO_2 emissions from rotary kilns, IEAGHG does not consider off-gases from rotary kilns viable for CCUS due to the relatively small scale (the largest production is approximately 0.3 million tonnes per year) and low CO_2 concentration in the flue gas (Santos 2012).

Coal can also be gasified to produce reducing gases for use in DRI processes. Coal gas as a reducing agent is a relatively new process and is in the early stages of commercialization. The MXCOL process, which combines coal gas with the Midrex DR process, is operational at the Jindal Steel & Power Ltd (JSPL) Angul steel plant. JSPL is the second commercial plant using this technology and the first to use a coal gasifier as the source of coal gas.

Iron can also be produced by smelt reduction where the hot metal is produced by reducing the Iron ore under oxygen. The most common of these processes is the COREX process. The off-gas from the COREX process contains a significant percentage of CO which can be used to produce heat or can undergo cleaning for use as extra CO gas for the Midrex process (Battle et al. 2013).

5.4 Carbon Dioxide Capture Technologies in the Steel Sector

Flue gases from the combustion of the process off-gases are the principal source of CO_2 emissions from steel making plants. Post-combustion capture of CO_2 from flue gases, as described in Chapter 2, is the simplest CO_2 capture technology for the steel industry. Post-combustion capture can potentially be applied to existing steelworks or planned for later implementation on a new steel plant that is required to be capture-ready.

Priority for application of CO_2 capture is based on the potential for CO_2 avoidance and the ease of CO_2 capture application. Potential for CO_2 avoidance is based on the total CO_2 emissions while the ease of CO_2 capture is based on the concentration of CO_2 in the stream and presence of other contaminants.

In the BF/BOF plant post-combustion capture of CO_2 from the power plant flue gas would have the potential to address about 40% of the steel plant CO_2 emissions and a further 20% from the host blast stove exhaust gases.

The European CO_2stCap project has investigated the implementation of partial CO_2 capture on steel plants with a focus on cost and ease of implementation (including heat integration) of CCUS. Hot stove gas and power plants gases, as well as capture from the intermediary BFG stream between the BF and the power plant, were investigated.

The BFG comprises about 22% CO and 22% CO_2 (IEAGHG 2013b). Figure 5.4 indicates that the CO_2 in the BFG fuel gas stream accounts for about 35% of the CO_2 emission from the steel plant. So, pre-combustion capture of CO_2 from BFG may be an option to consider. However, that pre-combustion capture from BFG would reduce the potential for post-combustion CO_2 capture from the power plant flue gas and hot stove flue gas.

Other, more complex integrated CO_2 capture processes specific to the steel industry are not relevant to capture-readiness. The integrated CO_2 capture concepts are not suitable for capture-ready plans because they are not amenable to the development of the two designs, with and without CO_2 capture, for short-term and long-term implementation.

5.5 Capture-ready Prospects in the Steel Sector

The potential requirement to designate a steel plant as capture-ready would be considered in the context of other state-of-the-art CO_2 emission reduction measures resulting in incremental improvements in the steel plant CO_2 emission factors. The iron and steel making process has underdone modifications to improve the process, energy consumption and CO_2 emissions including

- Blast furnaces have been modified for injection of auxiliary fuels through tuyeres;
- The injection of auxiliary fuels which are rich with hydrogen where available;
- EAFs becoming more flexible in operations to accommodate DRI process outputs;
- Midrex technology, the most widely used in DRI, based on natural gas;
- Improvements to the sintering process to increase flexibility;
- Gas recycling and optimised fuel gas utilization;
- Operation with mill scale and biomass together with fossil fuels as coke breeze or anthracite;
- Installation of gas holders for process off-gases BFG, COG and convertor gas enabling power plant to work in steady-state; and
- Processes in steel making were generally becoming more flexible.

The flexibility in modern steelmaking processes makes the process more amenable for carbon capture, which could make a step-change in the steel plant CO_2 emission factor.

The two main sources of CO_2 in BF/BOF routes are the power plant flue gas (40% of emissions) and the hot blast furnace flue gas (20% of emissions). The coke oven flue gas and the lime kiln exhaust are also amenable to post-combustion capture. A capture-ready plan could be developed to address 60-80% of the CO_2 emissions with post-combustion capture schemes. The requirements detailed in Chapter 1, in particular space allocation and CO_2 storage identification, would have to be addressed.

In the capture-ready plan, the preparation of the source gas for CO_2 scrubbing would have to be considered. If the feed gas is at a high temperature, then the capture-ready plan would need to include cooling of the gas. That might be done with a waste heat boiler to raise steam that could be used for solvent regeneration in the CO_2 separation process. Thermal integration would be an element of the CCUS readiness plan.

5.6 Economic Considerations for Carbon Dioxide Capture in the Steel Sector

CO_2 capture requires energy in the form of electricity and steam, which depends on the applied technology for CO_2 capture. Estimating the cost of CCUS is a complex exercise. As there are few operational CCUS sites, the cost estimates are based on assumptions with local and global factors. The

CO_2 costs of 63 iron and steel making routes under different scenarios have been assessed under the Ultra-Low CO_2 Steelmaking (ULCOS) program (Carpenter 2012). The various published costs of CCUS have been standardized by including CO_2 compression to 11 MPa and a capital cost scaling factor of 0.85 with 2007 as the base year (Kuramochi 2011). The cost comparison is presented in

Table 5.5. CO_2 capture from the COREX process using MEA based absorption has the lowest cost. However, the COREX-Midrex process at JSW India and Arcelor Mittal South Africa uses vacuum pressure swing adsorption for CO_2 removal.

Table 5.5 Key Parameters of Various Carbon Dioxide Capture Options for Blast Furnace and COREX

CO_2 Capture Technique	Specific Energy Consumption, GJ/tCO_2 Captured		Specific Capital Cost, $/(tCO2 captured/y)[a]
	Steam	Electricity	
Air-blown Blast Furnace			
Advanced Solvents	2.20–2.50	0.50	93.00
Chemical absorption (KS-1)	3.00	0.50–0.51	80.00–93.00
Chemical absorption (MEA)	3.20–4.40	0.51–0.55	93.00–120.00
Other amines	2.50–4.70	0.35–0.51	93.00–107.00
Physical absorption (Selexol™)	-	0.77	240.00
Selective carbon membrane	-	4.70	107.00
Top Gas Recycle Blast Furnace			
Chemical absorption (MEA)	3.30	0.62	80.00
Physical absorption (Selexol™)	0.21	0.93	80.00
Selective carbon membrane	-	0.79–0.88	80.00–120.00
VPSA	-	0.94	67.00
COREX			
Chemical absorption (MEA)	4.40	0.45	53.00

BF = blast furnace, GJ/tCO_2 = gigajoules per tonnes of carbon dioxide, MEA = monoethanolamine, tCO_2 = tonnes of carbon dioxide, VPSA = vacuum pressure swing adsorption.

Note: [a] Converted from source data in € with an exchange rate of $1= €0.75 in 2010.

Source: Kuramochi, T. 2011. CO2 capture in industries and distributed energy systems: Possibilities and limitations. Utrecht University.

Addition of CO_2 capture in an integrated iron and steel mill could have significant cost implication on the production of steel, which could have an impact on the commercial viability of steel plants. The data presented here is taken from various sources. The most comprehensive study on cost estimation of CO_2 capture for steel plants was conducted by IEAGHG (IEAGHG 2013b). This study was based on a typical integrated steel plant of European configuration as a reference plant. Two cases of CO_2 capture were considered, these are

- Case 1- Capture of CO_2 from flue gases of blast furnace stoves and from power generation
- Case 2- Capture of CO_2 from 3 major sources; blast furnace stoves, power generation and from flue gas of coke over underfired heaters and lime kiln.

Table 5.6 identifies the main sources of CO_2 in the reference plant and plants with CO_2 capture.

Table 5.6 Carbon Dioxide Emission with and without Carbon Dioxide Capture

CO_2 Emission breakdown	Base case (Reference Plant) kg/ton of HRC	CO_2 capture Case 1 kg/ton of HRC	CO_2 capture Case 2 kg/ton of HRC
Flue gas from			
Coke oven	191.37	191.37	19.14
Coke Oven	3.3	3.3	3.30
Sinter plant	289.46	289.46	289.46
Hot stove	415.19	41.51	41.51
OBF process gas fired heaters	----		
Reheating furnace	57.71	57.71	57.71
Blast furnace			
Lime plant	71.62	71.62	7.16
Power generation	982.13	210.8	227.31
Steam generation for CO_2 Capture	---	96.61	102.5
Flares			
Blast Furnace	19.73	19.73	19.73
BOF	51.02	51.02	51.02
Diffuse emissions			
PCI drying & ancillaries	7.76	7.76	7.76
Continuous casting	0.8	0.8	0.8
Hot mill rolling	0.04	0.04	0.04
Ancillaries transport fuel emissions	4.0	4.0	4.0
Total Emissions	2,094.14	1,045.73	831.42
Total CO_2 captured	NA	1243.13	1532.82
% CO_2 avoided	NA	50.1	60.3

BOF = basic oxygen furnace, CO_2 = carbon dioxide, HRC = hot rolled coil, OBF = oxygen blast furnace, PCI = pulverized coal injection.
Source: IEAGHG. 2013. Iron and Steel CCS Study (Techno-Economics of Integrated Steel Mill).

The CAPEX values of steel plants without and with capture for the corresponding cases in Table 5.6 are listed in Table 5.7.

Table 5.7 Capital and Operating Expenses for Steel Mills without and with Carbon Dioxide Capture

		CO_2 captured	
	Base case ($ million)	Case 1 ($ million)	Case 2 ($ million)
Plant Equipment—Major Process	2,772	2,993	3,014
Plant Equipment—Material Handling & Spare	244	247	247
Plant Equipment—Auxiliary, Utilities and BOP	350	350	350
Site development, construction and project engineering	562	562	562
Total installed cost—Steel mill	3,928	4,152	4,173

Contingency @5%	196	208	209
CO_2 capture plant	-	679	917
Total Investment cost—excluding recurring CAPEX	4,124	5,308	5,321
Recurring CAPEX (Blast furnace reline) every 15 years	232	232	232
Specific Investment cost ($/ton HRC)	1,031	1,259	1,330
Annual O&M cost $ (million)	1,782	1,966	2,031

BOP = balance of plant, CAPEX = capital expenditure, CO_2 = carbon dioxide, HRC = hot rolled coil, kg/ton = kilograms per ton, O&M = operation and maintenance.
Source: IEAGHG. 2013. Iron and Steel CCS Study (Techno-Economics of Integrated Steel Mill).

5.7 Timeline for Carbon Capture, Utilization and Storage-readiness in the Steel Sector

To achieve the cuts in the CO_2 emission from iron and steel industries, carbon capture is expected to play a significant role. Initially, the CCUS technologies were developed for energy and fossil fuel power generation.

Table 5.8 lists the status of various CO_2 reduction technologies. The implementation road map of these technologies is suggested by GCCSI. CO_2 capture from blast furnaces is ready for commercialization. DRI manufacturing has already implemented CO_2 capture on commercial steel units.

Apart from CO_2 capture, there are other opportunities to reduce carbon intensity for blast furnaces as shown in Figure 5.. The most feasible opportunities are related to energy and performance improvements. These include the use of coke and cogeneration of heat and electric power. Use of bio charcoal and plastic waste can reduce CO_2 emissions from the blast furnace. Smelt reduction can eliminate coking and sintering steps in the blast furnace process. Combination of best available technologies and CCUS can reduce emission per tonne of steel by 90% by 2050 if ongoing research and development can deliver the anticipated outcomes.

Table 5.8 Status of Carbon Dioxide Removal Technologies in Iron and Steel Industries

CCS Technology	Status	Implementation Road Map
CCS for Blast Furnace	Demonstration plant already operational. The Abu Dhabi Al Reyadah/Emirates Steel CCS project, based on chemical absorption, commissioned in 2016 Under COURSE 50 program technology to be transferred to the industry by 2030 POSCO's chilled ammonia process demonstration plant is in operation.	Equip 75% of new large blast furnaces units in OECD member countries with CCS by 2030, and 50% in non-OECD member countries. Equip 50% to 80% of refurbished plants between 2030 to 2050 with CCS

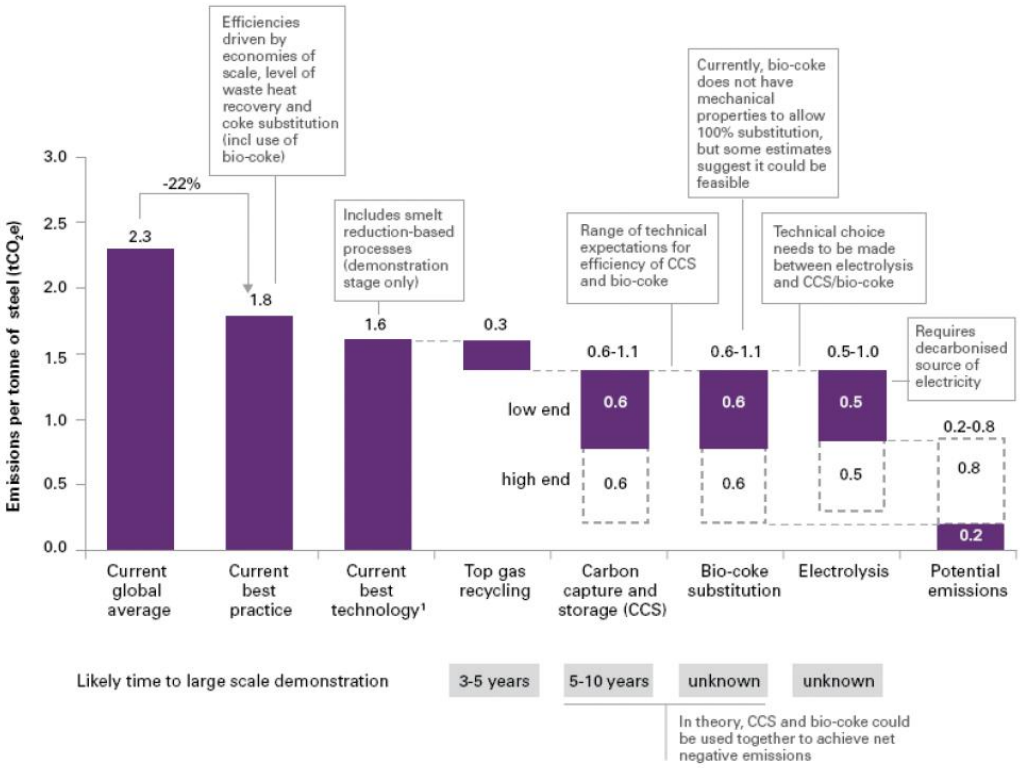
CCS for DRI	CO_2 capture for units with gasification and COREX DRI technology is already on a commercial scale	Equip 75% to 90% of DRI in OECD member countries with CCS by 2030, and 50% in non-OECD member countries. Equip 50% to 80% of refurbished plants between 2030 to 2050 with CCS

CCS = carbon capture and storage, CO_2 = carbon dioxide, DRI = direct reduction iron, OECD = Organisation for Economic Cooperation and Development.
Sources: Birat, J.P. 2010. Steel Sectoral Report. Global Technology Roadmap for CCS in Industry. United Nations Industrial Development Organization; GCCSI. 2018. " Capture of CO2 in the iron and steel sector." https://hub.globalccsinstitute.com/publications/technology-roadmap-carbon-capture-and-storage-industrial-applications/capture-co2-iron.

IEA developed a Technology Roadmap for CCUS industrial applications based on reducing CO_2 emissions to 50% of their 2005 level to limit global warming between 2 to 3 °C. About 20% of the total CO_2 reduction to be achieved by CCUS to meet the target of global warming (IEA 2011b).

According to the roadmap, industrial application of CCUS, particularly in developing countries, is the most promising short-term potential for CCUS. Steel sector would contribute about 23% (914 Mt CO_2) of the total required (43,000 Mt CO_2) CO_2 to be captured by 2050. India and China will play the leading role in CCUS deployment in the iron and steel sector. To achieve this target, the roadmap, implementation of CCUS in iron and steel sector is proposed in Figure 5..

Figure 5.4 Potential Technologies to Reduce Carbon Dioxide Emissions from Blast Furnace



Note 1: Approximate data only.

[1] Current best technically achievable.

Sources: IEA. BCG Analysis; Carbon Trust Analysis; Industry reviews; Appeared in Carbon Trust. 2011. "Steel." *International Carbon Flows.* The Carbon Trust. Retrieved from https://www.carbontrust.com/media/38362/ctc791-international-carbon-flows-steel.pdf.

Chapter 6 **Cement Sector**

6.1 Introduction to the Cement Sector

In 2017, the cement industry emitted 2.2 Gt CO_2, making it the largest source of direct industrial CO_2 emission for that year (IEA 2019). Cement is the primary active ingredient in concrete, which is ubiquitous in infrastructure projects. Ordinary Portland cement (OPC) is the most common cement mix, and various other cement mixes exist for niche purposes.

The primary raw material used to make cement is limestone ($CaCO_3$), which is calcined to calcium oxide (CaO) in the cement manufacturing process. The calcination process yields 440 kg of CO_2 for every tonne of limestone processed.[20] The calcination CO_2 emission is additional to the CO_2 emission from fuel use in the cement-making process.

Measures to reduce CO_2 emissions from cement works include

- Improvements in energy efficiency;
- Use of non-fossil fuels such as biomass and waste materials; and
- Replacement of calcined limestone with other cementitious materials such as fly ash or granulated blast furnace slag.

In a state-of-the-art rotary-kiln cement plant, these measures can potentially achieve a CO_2 emission factor as low as 500-600 kg of CO_2 per tonne of the cement product. Further significant reductions in CO_2 emissions would require CCUS.

The flue gas discharged from a cement plant is amenable to CO_2 capture because

- The flue gas is produced from as a single process stream (unlike CO_2 from the steel or petroleum industries);
- The flue gas has a high CO_2 content because most of the CO_2 originated from the calcination reaction;
- The flue gas has low levels of impurities when compared with other industrial processes. There is intimate contact between raw feed material and hot flue gas for heat exchange purposes. As a result, contaminants are absorbed from the flue gas; and
- There may be sources of low-grade waste heat available for use in a CO_2 capture process.

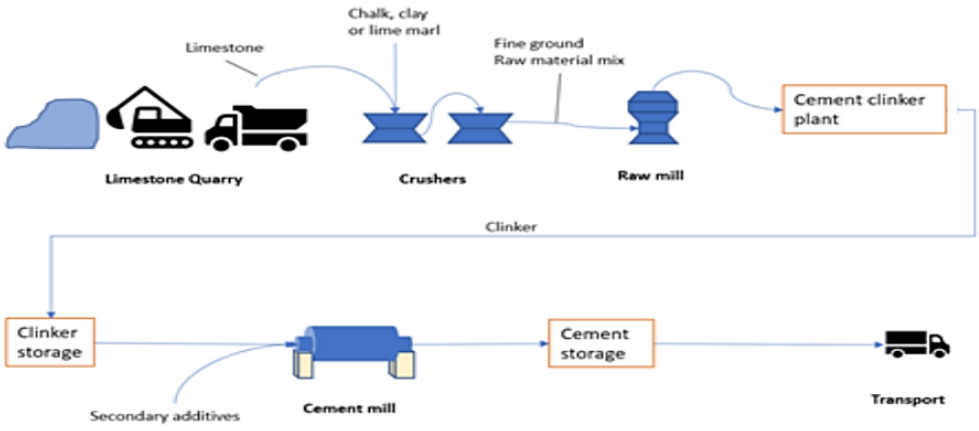
A case study of an existing cement plant at Citeureup, Java, Indonesia, examines the feasibility of adding CCUS. This is presented in Appendix B.

[20] $CaCO_3$ (mol wt 100) converts to CaO (mol wt 56) and CO_2 (mol wt 44).

6.2 Description of the Value Chain in the Cement Sector

Cement is a mixture of calcium silicates, aluminates and aluminoferrite, which is produced from a mixture of minerals, with the main ingredient $CaCO_3$. Figure 6.1 shows the value chain for cement production. Limestone is mined from a quarry and, together with chalk and clay, these components form the raw material mix, known as raw meal. After crushing and milling of the raw meal, it is fed to the cement clinker plant, where cement clinker is made by kilning the raw meal to drive off CO_2. The cement clinker is the main binder of a cement mixture. After milling and mixing with additives, this process forms the final cement powder. This product can be transported all over the world. After arriving at a location, concrete can be formed from the cement, sand, aggregate mixed with water.

Figure 6.1 Value Chain of Cement Manufacture

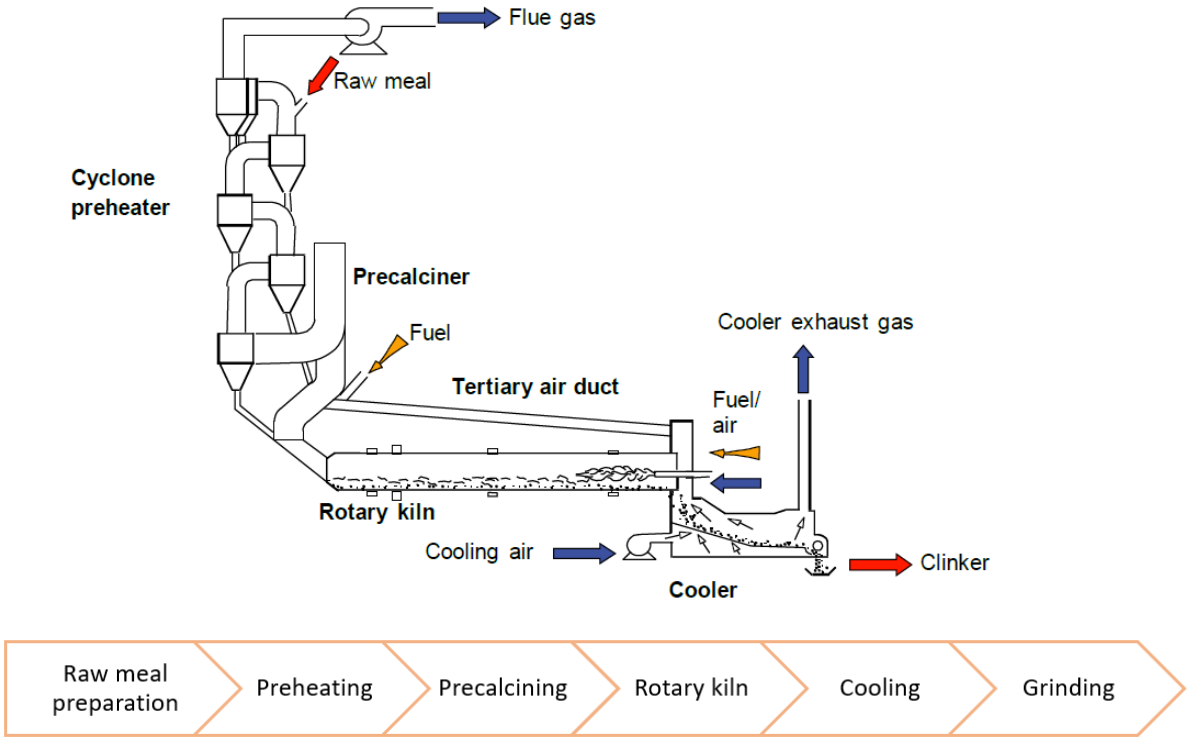


Source: Authors.

6.2.1 The Reference Cement Clinker Plant

Figure 6.2 shows the layout of a modern cement plant, built according to current best practice. The first part of this configuration is raw meal preparation, where limestone is ground before entering the cement plant. Next are five preheater cyclones, a calciner, rotary kiln and a grate cooler (di Milano 2016). A typical cement plant produces about one million tonnes of clinker per year (Mtpa).

Figure 6.2 Cement Production Process



Sources: Authors; IEAGHG. 2013. Deployment of CCS in the Cement Industry. IEAGHG, p. 139.

6.3 Carbon Dioxide Sources in the Cement Sector

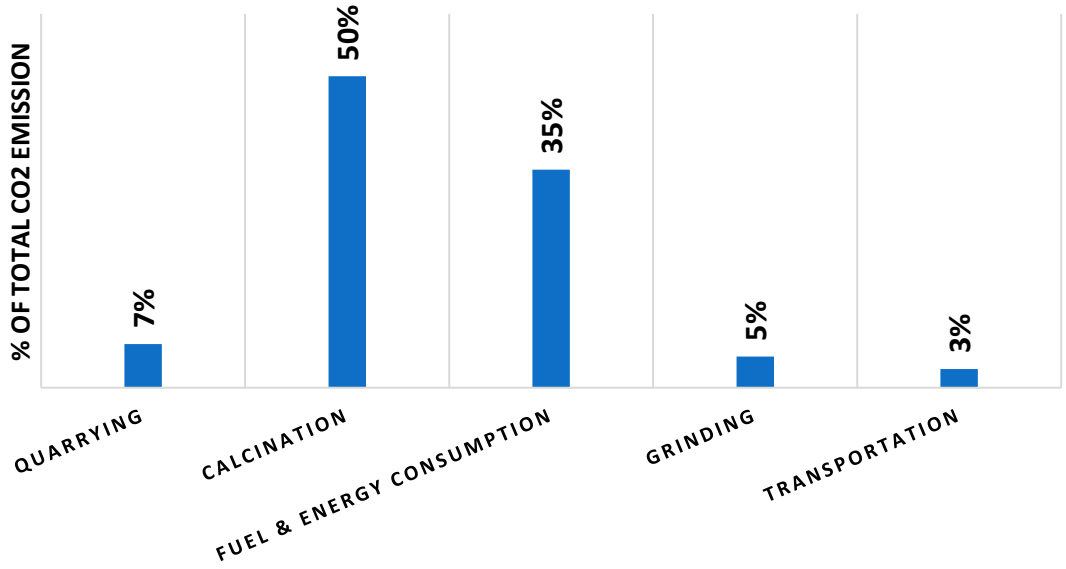
In the calcination process, transforming $CaCO_3$ to CaO releases CO_2 as a by-product. Due to this calcination process, cement production produces a significant amount of CO_2 in addition to the CO_2 from fuel consumption.

Apart from CCUS technologies, CO2 emission from the cement value chain can be reduced by improving energy efficiency, using alternative fuels, reducing the cement to clinker ratio, and using an alternative material mix for the cement clinker. Since most of the CO2 emissions arise during the conversion of CaCO3 to CaO, CCUS is the most effective method to reduce CO2 emissions from a cement clinker plant as it can capture CO2 emissions from the calcination reaction.

Figure 6.3 shows the distribution of the CO_2 emissions over the entire value chain (Maddalena, Roberts and Hamilton). CCUS would be able to make the deepest cuts in CO_2 emissions from the cement process (IEAGHG 2013a).

Apart from CCUS technologies, CO_2 emission from the cement value chain can be reduced by improving energy efficiency, using alternative fuels, reducing the cement to clinker ratio, and using an alternative material mix for the cement clinker. Since most of the CO_2 emissions arise during the conversion of $CaCO_3$ to CaO, CCUS is the most effective method to reduce CO_2 emissions from a cement clinker plant as it can capture CO_2 emissions from the calcination reaction.

Figure 6.3 Distribution of Carbon Dioxide Emissions Over the Main Processes in the Value Chain



Source: Ricardo Maddalena, et al. "Can Portland cement be replaced by low-carbon alternative materials? A study on the thermal properties and carbon emissions of innovative cements." *Journal of Cleaner Production* 186 (2018) 933e942. https://doi.org/10.1016/j.jclepro.2018.02.138.

6.4 Carbon Dioxide Capture Technologies for the Cement Sector

There are four types of CO_2 capture process relevant to cement production:

- Post-combustion capture involving chemical absorption;
- Oxy-fuel combustion (full or partial);
- LEILAC Direct Separation CO_2 capture; and,
- Calcium looping.

These could all potentially be applied in a new cement plant design. However, the latter three processes are not amenable to retrofitting to a cement works at a later time in the context of making an existing cement plant design capture-ready.

6.4.1 Post-Combustion Capture

Post-combustion capture of CO_2 is the most mature form of carbon capture and is the only form that has been realized on a commercial scale. The Norcem project is implementing chemical absorption in partial carbon capture. A 1 Mtpa cement plant would require a CO_2 capture plant with 0.6 to 0.7 Mtpa capacity for full CO_2 capture. Chemical absorption of CO_2 with amines is the mature commercialized technology that would be suitable for planning a capture-ready cement plant. A 30 wt% aqueous solution of monoethanolamine (MEA) is a benchmark, well-referenced,[21] solvent for post-combustion CO_2 absorption, but more sophisticated solvents have been shown to give improvements in performance in some circumstances and development is on-going.

Post-combustion CO_2 capture with amines is an end of process solution, which requires the gas feed to be cleaned before entering the CO_2 scrubber to prevent degradation of the amine solvent by SO_2, NOx or dust. In the cement manufacturing process, the flue gas from the combustion processes may contain SO_2 if the fuels contain sulphur. However, the flue gas is repeatedly contacted with finely ground calcium carbonate in the cyclone preheater section of the process. A side effect of this heat transfer process stage is desulphurization of the flue gas, so additional desulphurization may not be required.

A generic post-combustion capture amine scrubbing process is described in Chapter 2. The Citeureup cement plant case study in Appendix B reports CO_2 concentrations of 27% to 32% compared with 15% in a typical power plant flue gas. This higher CO_2 concentration in the amine scrubber feed gas would result in an increase in the CO_2 concentration in the CO_2-rich amine stream, which would reduce the regeneration energy demand per tonne of CO_2.

Integration of post-combustion CO_2 capture with a cement plant is relatively easy, considering it is an end-of-pipeline solution. It will be important to allow enough space on-site. Low-pressure steam for post-combustion capture may be partly obtained from integrated heat recovery in the cement plant. Additional steam might be obtained by import from a combined heat & power plant (CHP) (di Milano 2016). Since the requirement is for low-grade energy, it might be provided by carbon-neutral bioenergy, which is a carbon-neutral and less intense heat source than fossil fuel.

6.4.2 Oxy-fuel Combustion

In oxy-fuel combustion oxygen is used instead of air, resulting in a much higher concentration of CO_2 coming out of the process. To prevent damage to the kiln by high temperatures, the flue gas containing mostly CO_2 is recirculated to the calciner and kiln. Oxy-fuel combustion can be integrated with the cement production process in a partial and a full configuration. For both configurations, the necessary additions are an air separation unit, CO_2 purification unit, CO_2 recirculation, and clinker cooling. The high oxygen concentration in oxy-fuel combustion increases the temperature profile of the kiln.

[21] Performance data for 30% MEA solvent is extensively reported in the non-proprietary open literature.

6.4.3 LEILAC Direct Separation Technology

In the LEILAC technology, which is still under construction, the calciner has been adapted to separate CO_2 from burning fuel and CO_2 from the calcination reaction. With the LEILAC technology 60% capture rate is possible because the CO_2 from calcination is kept separate from the CO_2 from products of fuel consumption.

6.4.4 Calcium Looping

The technology for integrating cement plants with calcium looping technology is under development. Calcium Looping is based on a post-combustion CO_2 capture process, where CO_2 is captured by reaction with solid calcium oxide (CaO) and regeneration of the sorbent occurs by calcination of $CaCO_3$ to CaO. The materials used in calcium looping are the same as the $CaCO_3$ and CaO from the cement process. Therefore, there are two options of integrating calcium looping with a cement plant, either as a separate post-combustion process installation or by the integration of the cement plant and the calcium looping system (CSIC 2016). The CLEANKER project aims to increase the TRL of this technology in the Cement Sector. This project started in 2018.

Table 6.1 Pros and Cons of Each Carbon Dioxide Capture Technology

	CO_2 capture rate	Advantages	Disadvantages	Adjustments to existing cement plant	Additional equipment
Post-combustion carbon capture	90%	Proven technology	Higher energy requirement than oxy-fuel technology and direct separation. For 90% capture, part of the heat needed may be supplied by integration with the cement plant Flue gas must be cooled down to 40 ℃.	End of pipeline post-combustion carbon capture unit, so no adjustments to existing cement plant. Heat recovery integration to reduce supplement of additional heat needed for regeneration of the solvent	Post-combustion carbon capture unit
Full Oxy-fuel technology	>90%	Lower energy requirement than post-combustion carbon capture. It increased clinker production.	Lower technology readiness level and higher associated technical risk for integration with the cement plant.	No redesign of preheating tower. Redesign of kiln burner Possible two-stage clinker cooler	Addition of air separation unit CO_2 purification unit
Partial Oxy-fuel technology	60-75%	Lower energy requirement than post-combustion carbon capture. Increased clinker production.	Lower technology readiness level and higher associated technical risk for integration with the cement plant.	No adjustments to kiln, cooler and raw mill. Air tightness of preheater tower and calciner Different way of operating the calciner	Addition of air separation unit Preheating tower added CO_2 purification unit
LEILAC direct separation technology	60%	Low energy cost Minimal adaption to cement plant	Technology still under development	Replacement of calciner with direct separation calciner	

Calcium Looping	94%	Potential higher efficiency due to extensive integration with cement plant chemistry.	Technology still under development Technology might cause problems for the rotary kiln	Replacement of calciner with oxygen-fired calciner Extensive reconfiguration of layout of cement plant	Air separation unit Oxygen-fired calciner CO_2 purification unit Calciner / Carbonator

CO_2 = carbon dioxide.
Note: More technologies have been studied in the CEMCAP project, although based on simulation results. (e.g. chilled ammonia, membranes with liquefaction).
Source: Authors.

6.5 Capture-Ready Prospects in the Cement Sector

The flue gas discharged from a cement plant is amenable to the addition of post-combustion CO_2 capture as a retrofit technology because the gas is produced in a single location, is relatively clean and has an elevated CO_2 content. The development of a capture-ready plan for a new or an existing cement plant based on post-combustion capture would require allocation of space for the additional equipment, provision of energy, and identification of a viable transport and storage plan. Adaptation of the core elements of the host plant design would not be required.

In contrast, the other CO_2 capture schemes briefly described in Section 6.4 would involve major changes to the host cement process and are not amenable to the development of a CCUS-ready plan for retrofitting to a host plant.

6.6 Economics of CO_2 Capture in the Cement Sector

To implement CCUS at a cement plant, a feasible, economical cost for a newbuild or retrofit cement plant is essential. Some technical and economic evaluations of post-combustion carbon capture and oxyfuel combustion technologies were collected from the literature. The results, presented in Table 6.2, show that the estimated CAPEX and OPEX investments for post-combustion carbon capture are higher than for Oxy-fuel technology.

Table 6.2 CAPEX and OPEX Estimates for Cement Plant CO_2 Capture Plans

	CCS plan	Clinker production (Mtpa)	Capital investment (million $\$_{2013}$[a])	Operation & maintenance (million $\$_{2014}$/year)	References
Post-combustion capture 90% capture	**Newbuild**	1.0	590.0–720.0		b
	Retrofit	2.0	285.0 (China)		b/c
	Retrofit	1.0	325.0–465.0		b/d
	Retrofit	1.8	345.0 ($\$_{2014}$)	57	e
Oxy-fuel >90% capture	**Newbuild**	1.0	390		b/d
	Retrofit	1.8	290.0 ($\$_{2014}$)	49	e
	Retrofit	1.0	140.0		b/d
Partial oxy-fuel 60%-75% capture	**Newbuild**	1.0	365.0		b/d
	Retrofit	1.0	130.0–140.0		b/d
	Retrofit	1.0	115.0		b/d

CCS = carbon capture and storage, CO_2 = carbon dioxide, Mtpa = million tonnes per annum.

Notes:
[a] Converted from source data in € with an exchange rate of US$1=€0.75 in 2010
[b] Hills, T., D. Leeson, N. Florin, and P. Fennell. 2016. "Carbon Capture in the Cement Industry: Technologies, Progress, and Retrofitting," Environ. Sci. Technol., vol. 50, no. 1, pp. 368–377;
[c] Liang, X., and J. Li. 2012. "Assessing the value of retrofitting cement plants for carbon capture: A case study of a cement plant in Guangdong." Energy Convers. Manag, vol. 64, pp. 454–465;
[d] Li, J., P. Tharakan, D. Macdonald, and X. Liang. 2013. "Technological, economic and financial prospects of carbon dioxide capture in the cement industry." Energy Policy, vol. 61, pp. 1377–1387;
[e] Gerbelová, H., M. VdSpek, and W. Schakel. 2017. "Feasibility Assessment of CO2 Capture Retrofitted to an Existing Cement Plant: Post-combustion vs. Oxy-fuel Combustion Technology." Energy Procedia, vol. 114, no. November 2016, pp. 6141–6149.
Sources: Hills, T., D. Leeson, N. Florin, and P. Fennell (2016); Liang, X., and J. Li (2012); Li, J., P. Tharakan, D. Macdonald, and X. Liang (2013); Gerbelová, H., M. VdSpek, and W. Schakel (2017).

The cost for the LEILAC direct separation technology is unknown at present. It is known that the calciner unit would have to be replaced with the direct separation unit. This reactor would have to operate at higher temperatures and might need higher quality material to handle this. Therefore, the cost of the LEILAC direct separation technology would be higher than a conventional calciner unit. Likewise, the costs for the experimental calcium looping technology are unknown.

6.7 Timeline for Carbon Capture, Utilization and Storage-Readiness in the Cement Sector

At present post-combustion capture is the only mature CO_2 capture technology. It is important to gain experience with operating capture plants for the cement industry, as currently there is only experience with power plants. Post-combustion carbon capture is a technology that is suitable for both new cement clinker plants and for retrofits in the context of capture-ready.

Oxy-fuel technology is likely to have lower capital cost and operational cost than post-combustion carbon capture (IEAGHG 2013a). If there is sufficient drive for technological development of oxy-fuel technology, then from 2030 onwards new cement plants might be able to implement this technology but retrofitting an existing plant would require extensive modification to almost all equipment in the plant. Partial-oxy-fuel process, where only the calciner and preheater would require modification, maybe an interim option.

The LEILAC direct separation technology is a promising technology. After pilot plant testing more information will be available for the technical possibilities of incorporating this technology in new cement plants.

Calcium looping technology is still in a basic research state (CSIC 2016). Therefore, it is hard to predict the future development of technology. Calcium looping would require changing the entire configuration of the cement clinker plant, so it is not suitable for capture-ready designs.

Chapter 7 **Petroleum Sector**

7.1 Introduction to the Petroleum Sector

The petroleum sector comprises three principal centres of activity:

- crude oil refining;
- raw natural gas processing; and
- downstream petrochemical processing.

There are typically many CO_2 point sources dispersed across a refinery complex as indicated in Table 7.1. The largest CO_2 emissions arise from process heaters, utilities, fluid catalytic crackers (FCC), and from hydrogen manufacture. Most of the CO_2 emissions are flue gas from many combustors. A smaller amount of CO_2 is separated in the hydrogen production process.

Natural gas processing activities depend on the composition of the raw natural gas and may include separation of natural gas liquids, desulphurization, and reduction in CO_2 content. Pipeline natural gas supplied to customers typically has a specified maximum of 4% CO_2 content. In the case of a natural gas source with higher CO_2 content, the natural gas processing plant includes separation of pure CO_2, making CO_2 capture straightforward.

Petrochemical plants are complex, unique industrial installations, which depend on the nature of local feed materials available, and the local market for petrochemical products. Hence there is no common basis on which to consider CO_2 capture. When a new petrochemical plant is being designed, CO_2 capture-ready criteria should be regarded as to future-proof the plant. Petrochemical plants are not considered further in this review of capture-readiness.

7.2 Description of the Value Chain in the Petroleum Sector

A refining process involves the following elements: crude oil purchase, crude oil transportation to refineries, refining process, product transportation, and product delivery to its end users. A typical refinery product slate includes LPG, naphtha, solvents, gasoline, jet fuel, diesel fuel, oil heating gas oil, light residual oil, lubrication oils, heavy fuel oil and bitumen. The conversion of raw crude oil into these refined products adds value to the energy-containing materials that are processed.

The processes for producing refined products require a significant amount of heat. The heat is usually provided onsite from refinery fuel gas or through the purchase of steam from a nearby heat and power plant. The combusted fuels in a refinery are called “Fuel and Loss” and can account for 2%-10% of the refinery’s crude oil energy content.

The economics of oil refining depends on the final product slate that a particular plant is producing. Modern refineries can modify the final product with advanced control system product planning. Although the product slate for a specific refinery can be adjusted, most refineries will not change the product slate often.

Table 7.1 Carbon Dioxide Emission Sources at a Typical Refinery Complex

CO_2 emission source	Description	% concentration of CO_2 (dry basis)	Impurities in flue gas (dry basis)	% of total refinery emissions	Potential CO_2 capture method
Combustion processes	Gas fired burners	10% (natural gas) 10% (refinery gas) 19% (synthesis gas)	O_2, SO_2, NOx	30-60%	Post-combustion capture
	Heavy oil burners	13%	O_2, SO_2, NOx		
Utilities	NGCC gas turbine	4 %(CCGT)	O_2, SO_2, NOx		
	Steam boilers	13% (heavy residue) 15% coal	O_2, SO_2, NOx, particulates (coal)	20-50%	Post-combustion capture
FCC	Furnace	10% (refinery gas) 15% (FCC off-gas) 13% (heavy residue)	O_2, SO_2, NOx	20-30%	Post-combustion capture
	Oxy-fuel furnace	95%	N_2, O_2, SO_2, NOx		Oxy-fuel
Hydrogen production	SMR or heavy fuel gasification with CO_2 separation	99%	Possibly H_2S	5-20% (Hydrogen production is greater if the refinery includes hydrocracking)	Just cooling and compression
	SMR or heavy fuel gasification with PSA hydrogen production	90-95%	H_2, CO, CH_4, H_2S		Purification with cooling and compression
Flares	Emergencies and maintenance	low	Depends on material flared	Minor	CO_2 capture is impractical

CCGT = combined cycle gas turbine, CO = carbon monoxide, CH_4 = methane, FCC = fluid catalytic crackers, H_2 = hydrogen, H_2S = hydrogen sulphide, N_2 = nitrogen, NOx = oxides of nitrogen, O_2 = oxygen, PSA = pressure swing adsorption, SMR = steam methane reforming, SO_2 = sulfur dioxide.

Sources: Straelen, J. van, F. Geuzebroek, N. Goodchild, G. Protopapas and L. Mahony (2010), CO2 capture for refineries, a practical approach." International Journal of Greenhouse Gas Control 316-320.

For optimizing the final product slate, most refineries include catalytic cracking, and thermal cracking to increase the yield of the more valuable light liquids and hence improve the economics of the refinery. Catalytic reforming, hydrotreating and sulphur recovery are used in refineries to meet product quality specifications. These unit operations are common in all refineries. In addition, many advanced refineries include a hydrocracking operation to convert heavy crude oil to lighter, more valuable liquids. The hydrocracking process significantly increases the hydrogen requirement of the refining operations.

Some existing refineries might not be suitable to be retrofitted with CO_2 capture due to the tight layout or due to the already optimized heat and power integration within the facilities. Therefore, ensuring the original plant is designed to be capture-ready is essential for new oil refineries.

7.2.2 Natural Gas Processing

Where a natural gas resource contains more than about 5% CO_2, the excess CO_2 needs to be removed to produce a natural gas product to meet specifications for pipeline distribution to general consumers. Pre-combustion capture technologies would be used for CO_2 removal from the high-pressure fuel gas. The cost of CO_2 separation is part of the natural gas plant operating costs. Normally, the removed CO_2 would be vented to the atmosphere. However, the addition of CO_2 compression and purification equipment can provide a low-cost CO_2 product for utilization or storage.

7.3 Carbon Dioxide Sources in the Petroleum Sector

7.3.1 Carbon Dioxide Sources from Oil Refining

Oil refineries are all different because they are individually designed to suit particular types of crude oil and to meet particular local needs and market requirements in the context of specific local conditions. Table 7.1 shows a generic list of CO_2 sources in a modern oil refinery. CO_2 emissions arise from process heaters, utilities, fluid catalytic crackers (FCC), hydrogen manufacture, and from flares.

Process heaters are either direct-fired with refinery fuel gas combustors or by heat exchangers with steam from a central utility plant. The utility plant producing steam and electricity may be fired by coal, residual fuel oil or refinery fuel gas. Gas turbines may be used in utility plants. The FCC unit is a single large user of fuel in the cat cracker furnace, which may be fired with residual fuel oil, collected refinery fuel gas or the specific off-gas from the cat cracker. All these sources of CO_2 yield products of combustion, which are amenable to post-combustion capture. The FCC unit may be amenable to being designed for oxy-fuel combustion.

Hydrogen production involves the preparation of a gas comprising principally CO_2 and hydrogen which is then separated. The source gas may be produced by gasification of coal or heavy residual oil, or by steam reforming of natural gas, followed by shift conversion. The refinery fuel gas, which contains light hydrocarbons, is not suitable for conversion to a CO_2/H_2 gas mixture. The separation of CO_2/H_2 can be either with a CO_2 removal process, which gives a high purity CO_2 and low purity hydrogen or with a Pressure Swing Absorption system which gives a higher purity of hydrogen and a lower purity of CO_2. The high purity CO_2 from a CO_2 removal process provides a low-cost CO_2 capture opportunity.

The flaring of waste liquids and gases is carried out intermittently for safety purposes and during maintenance procedures. The variable and intermittent nature flares with make them unsuitable for CO_2 capture.

7.3.2 Carbon Dioxide from Natural Gas Processing

In many oil and gas fields, the CO_2 separated from natural gas is used as a source of CO_2 for enhanced oil recovery (EOR). Of the eight operating large scale (>0.5 million tonnes per year (Mtpa)) CCUS plants listed by the Global CCS Institute (GCCSI) in 2012, four involve CO_2 separation in a gas processing plant for use in EOR (GCCSI 2016).

The flagship Norwegian CCUS project at Sleipner in the North Sea, which has been operating at 1 Mtpa since 1996, involves reducing the CO_2 content of natural gas from 9% to 4% and injecting the captured CO_2 into a deep saline aquifer beneath the North Sea.

The Natuna gas field in the South China Sea is an extreme case of natural gas contaminated with CO_2. The raw Natuna gas contains 71% CO_2. If that CO_2 were to be vented to atmosphere, then the resulting natural gas product would be more greenhouse intensive than coal.

7.4 Carbon Dioxide Capture Technologies for the Petroleum Sector

7.4.1 Post-Combustion Capture

As shown in Table 7.1, the principal CO_2 emissions from an oil refinery are flue gases from the combustion of hydrocarbon fuels, which are amenable to post-combustion capture. Post-combustion capture technologies are described in Chapter 2.**Error! Reference source not found.** There are multiple sources of flue gas in on oil refinery complex, which would need to be combined for feeding to an economic scale of CO_2 capture plant. A key challenge, particularly for retrofitting of any type of CO_2 capture equipment at an existing refinery, is finding the space required for the infrastructure, including flue gas ducts, steam off-take facilities and the CO_2 processing equipment, because refineries are generally constructed with a compact energy-efficient process equipment layout (ICF 2010).

When a centralised CO_2 capture facility involves mixing flue gas streams from different emission sources, it may be preferable to prepare the flue gas stream to a common CO_2 scrubbing specification (e.g.

Table 4.3) prior to mixing. For example, a flue gas with a high SO_2 content that meets environmental criteria would need to be further desulphurized to meet CO_2 scrubbing feed gas criteria before it is diluted with other flue gases. However, the practical feasibility of making provision for an additional unit operation in the refinery layout would add complexity to the refinery capture-ready design.

7.4.2 Oxyfuel Combustion

Several companies are developing and commercializing oxy-fuel burners for refinery applications, particularly for FCC operation. Certain design challenges such as addressing heat flux that could induce fouling due to coking in some heaters and improving the energy efficiency of air separation units for the production of oxygen, however, still need to be overcome (ICF 2010). Oxyfuel combustion is a potential

CO_2 capture technology for new construction of some refinery units, but retrofit conversion to oxyfuel combustion would be impractical in the context of an established refinery.

7.4.3 Carbon Dioxide By-Product Processing

As identified in Table 7.1 and Section 7.3.2, there are significant sources of CO_2 from hydrogen production and natural gas processing where the energy-intensive CO_2 separation is a part of the host process. In these cases, the preparation of CO_2 for transport and utilization or storage only involves lower-cost by-product processing.

In this case, the starting point for retrofitting CO_2 capture for CCUS is the separated CO_2 stream, which by default would be vented to the atmosphere. Where that CO_2 has been separated by a physical separation process, such as Selexol or Rectisol, the CO_2 is 99+% pure with minor contaminants of water and possibly H_2S. The delivered CO_2 is required at supercritical pressure, e.g. 11 MPa. Water removal is achieved by cooling and condensing water from the CO_2 in multiple compression stages. If the source CO_2 contains H_2S at unacceptable concentrations for the CO_2 product use or storage, then additional H_2S scrubbing processes would be included.

In the case of pressure swing adsorption (PSA) hydrogen production, the CO_2-rich coproduct would contain hydrogen and light hydrocarbons. To purify the CO_2 as a product for delivery to use or storage, additional PSA stages would be required to produce a high-concentration CO_2 stream. A mixed gas stream containing H_2, CO, CO_2, and hydrocarbons would also be produced, which would be recycled to the refinery fuel gas collection system.

7.5 Capture-Ready Prospects in the Petroleum Sector

A fundamental question that needs to be answered before designing any refinery, gas processing plant or petrochemical as a capture-ready plant is: *"Where will the captured carbon dioxide be stored or utilized after the retrofit in the future?"* If there is no possible way to transport and use or store large volumes of CO_2 in an effective way, then there is no purpose of considering the retrofitting of CO_2 capture schemes.

Most of the capture technology has been tested in various applications at demonstration scale around the world, and the need for constructing a pilot plant at any refinery and petrochemical plant is limited. The way to accelerate technology uptake in the petroleum sector should be through full-scale capture projects rather than a pilot-scale testing project.

7.5.1 Post-Combustion Carbon Dioxide Capture from a Petroleum Refinery

Combustor flue gases are the main CO_2 emissions from petroleum refineries. Post-combustion capture of those emissions would be technically feasible with additional equipment without the need for reconfiguration of refinery operations. Post-combustion capture technologies are described in Chapter 2. With enough space to accommodate the additional equipment and an identified destination for the captured CO_2, a refinery design could be made capture-ready.

However, oil refineries are individually designed to suit local circumstances, and there are multiple flue gas sources of differing properties, so the cost of implementing bulk CO_2 capture in the context of gathered flue gases from an oil refinery is likely to be greater than the corresponding cost per tonne of

CO_2 captured from a coal-fired power plant. So, the prospects of post-combustion CO_2 capture from oil refining are unlikely to be in the first tranche of applications of CCUS.

7.5.2 Carbon Dioxide from Hydrogen Production

The separation of a stream of pure CO_2 followed by its release into the atmosphere at the same site, is the common practice for hydrogen production facilities and natural gas processing plant. This does not constitute CO_2 capture in the context of CCUS. In these cases, the additional equipment for CCUS would be only that required for CO_2 processing and delivery.

The cost of processing and delivery only of separated CO_2 is much less than the cost of other CO_2 capture schemes, such as post-combustion capture from flue gas. Therefore, as the penalties increase for the discharge of CO_2 into the atmosphere, CCUS applied to CO_2 from hydrogen production in refineries is likely to occur early in the wide-scale implementation of CCUS.

Box 7: Example of Carbon Dioxide Utilisation from a Petroleum Refining Operation

At the Marsden Point petroleum refinery in New Zealand, which is a hydrocracking refinery, 50,000 tonnes per year of food-grade CO_2 is produced as a by-product from the hydrogen production plant. This is 7% of the refinery CO_2 emissions. The CO_2 production unit cost US$30 million in 2016. The food-grade CO_2 is distributed by road by BOC to the New Zealand food and horticultural industries.

7.5.3 Carbon Dioxide from Natural Gas Processing

The capture, transport, utilisation, and storage of CO_2 removed from natural gas is well established, as described in Section 1.2. Again, as the penalties increase for the discharge of CO_2 into the atmosphere, CCUS applied to CO_2 from natural gas processing plants is likely to occur early in the wide-scale implementation of CCUS.

7.5.4 Multiple Technologies at the Same Site

For power plants, hydrogen plants and natural gas processing plants (and cement plants) the CO_2 source is in a single uniform process stream, so one CO_2 capture technology at large scale would be used. For refineries and petrochemical plants (and steel plants), this arrangement may not be optimum. Refineries are complex environments with many unit operations yielding many sources of CO_2 with different properties. Whilst much smaller CO_2 source may be combined into a single mixed gas stream for CO_2 capture, some of the larger flue gas sources, notably the cat cracker furnace flue gas, may use a separate CO_2 capture process tailored to the properties of the CO_2 source. The range of opportunities and technologies for CO_2 capture would be a consideration for the designers of capture-ready plants.

7.5.5 Novel Technology Application

Designing a plant to be capture-ready requires a definite process design based around a solid alternative mass and energy balance that would be switched over to at the time of retrofitting. The front-end engineering design (FEED) of the plant would be based on proven technologies. Advances in technology

are slow and incremental. It might be the case that the performance of materials might be improved over time, or the formulation of chemicals might be refined. However, such advances are more likely to improve the yield of a plant, or to reduce the capital or to operate cost of the plant, rather than change the plant design. Capture-ready status based on speculative breakthrough advances in technology would not be credible.

7.6 Economic Considerations for Carbon Dioxide Capture in the Petroleum Sector

Since petroleum sector plants are individual installations, there are no public-domain generic economic assessments of potential costs of CCUS or CCUS readiness. Therefore, the economics of CCUS in the petroleum sector needs to be considered relative to power-generation based schemes.

7.6.1 Carbon Dioxide from Hydrogen Production and Natural Gas Processing

Waste streams of CO_2 from hydrogen production and natural gas processing present a low-cost opportunity for CCUS, with commercially operating examples in place. Since the cost of bulk separation of CO_2 is borne by the host process, the marginal cost of producing a transportable CO_2 stream is probably in the order of $10 per tonne of CO_2 for processing and compression. There are no other industries offering pre-separated sources of CO_2, except for the permanent gases separated from geothermal fluid in some cases.

7.6.2 Carbon Dioxide from Refinery Post-Combustion Capture

In comparison with a power station, the scale of the CO_2 source in refinery flue gas is much smaller. A mid-sized refinery might generate about 500,000 tonnes of CO_2 per year, compared with 1000 MW coal-fired power plant generating about 5 million tonnes per year of CO_2 in the flue gas. An additional cost for CO_2 capture in a refinery context would be the infrastructure to gather flue gases into a common CO_2 capture facility. Accordingly, the cost per tonne of CO_2 captured from refinery flue gases might be about double to cost per tonne of CO_2 capture from a coal-fired power plant.

Notwithstanding that potentially higher cost of CO_2 capture, it would be prudent when designing a new oil refinery, gas processing plant or petrochemical plant to avoid barriers to the future implementation of CO_2 capture in the event of changes in the regulatory environment. The marginal cost of making a plant capture-ready will depend on the circumstances.

The principal physical costs would be land allocation and increased plant layout infrastructure to accommodate flue gas collection ducts. There may also be additional work for the refinery design team in taking account of capture-readiness requirements in the FEED.

7.7 Timeline for CCUS Readiness in the Petroleum Sector

The first step in CO_2-capture-readiness in the petroleum sector would be to review all existing hydrogen production units and natural gas processing plants to determine the feasibility of processing and compressing the separated CO_2 and the potential for utilisation or storage of that CO_2. For those cases

where CCUS is technically feasible, a costing exercise should be carried out to determine the economic or legislative conditions required to trigger CCUS implementation.

The next step would be to ensure that CCUS readiness is included in the design of all new petroleum facilities. That would future-proof those facilities, which should make any marginal costs of CCUS readiness economically justifiable.

If the regulatory incentive for CCUS is progressive, then the implementation of deep CCUS on refinery flue gas would be unlikely to occur until after the application of CCUS to coal-fired power plants is commonplace. At that time, the availability of CO_2 storage facilities may be a limitation. Progress and innovations in CCUS technologies may bring forward the feasibility of implementing CCUS.

Chapter 8 **Financing Carbon Capture Utilization and Storage Readiness**

The following sections will shed light on traditional sources of financing as well as funding for CCUS readiness projects, levels of pre-investments required, common financing mechanisms available, and financing activities and policy recommendations to take capture-readiness from an early adoption stage to an integral policy component for the future.

8.1 Traditional Sources of Financing

Coal-using industries such as steel, cement and power plants are generally financed of three main sources of capital: sponsor equity, tax equity, and debt. The blend and proportion of each of the capital sources may vary from transaction to transaction and are briefly outlined in the following subsections.

8.1.1 Sponsor Equity

Sponsor equity for most projects resembles traditional equity, likely to be provided by the original developer of the project. The sponsor puts their own money on the line and has "skin in the game" with typically an investment that is going to be the first to suffer losses. The equity sponsor received distributions of profits through dividends. Because the sponsor has the highest risk in the project development, it also typically seeks a higher return on investments (NREL 2017).

8.1.2 Tax Equity

A tax equity investor commits an upfront capital to a project in lieu of tax credits for the future. This type of investment requires significant capital and future tax liability, and therefore tax equity investors are often large financial entities such as banks and insurance funds (NREL 2017).

8.1.3 Debt Capital

Debt capital is a contractually led loan that needs to be repaid by the borrower and occurs without the lender having any ownership stake in the company. Debt is commonly understood as a lower-risk and low-cost funding source compared to equity. Debt capital benefits from additional financing protections such as access to collateral and rights to assume control of a defaulting company (NREL 2017).

Apart from the funding structures, there are other elements that are needed to make a project successful, such as prudent risk management, efficient capital and ownership structures, and stable revenue models for the life of the project that can complement these financing structures.

8.1.4 Corporate Finance

Incorporate finance, projects are financed on the balance sheet of the sponsors (the company building the project). Sponsors typically procure capital by demonstrating to lenders that it has enough assets on its balance sheet to use as collateral for the debt in the case of default. In other words, the lenders will have the ability to foreclose on the sponsor company's assets, sell them, and

use the proceeds to recover its investment in the event that the sponsors are not able to pay the debt.

8.1.5 Project Finance

In project finance, lenders to a project have recourse (or claim) only to the *project's* cash flows and assets. The only collateralized asset is the asset that is going to earn cash flows in the future. In effect, the recourse for the lenders is limited only to the project being constructed and does not extend to any other asset of the sponsors. Such a project is therefore also called an "off-balance sheet" transaction. In some cases, project finance in developing countries is generally backed by sponsor or government guarantees to provide lenders with extra comfort (The World Bank 1995). The overall risk-return features are summarized in Table 8.1.

Table 8.1 Comparison of Corporate Finance versus Project Finance

Description	Corporate Finance	Project Finance
Type of capital	Not limited to the duration of the project.	Limited to project duration
Finance vehicle	Multi-purpose on company balance sheet	Special purpose vehicle for the project
Transaction cost	Low and easy	Higher due to complexity of project work
Cost of capital	High	Low
Basis of credit decision	Balance sheet and cash flow of the sponsor	Project cash flow and technical feasibility
Variable underlying credit decision	Robustness of company balance sheet. The performance of the entire corporation with a focus on the overall balance sheet and cash flow	Economic and technical feasibility study, project documentation and projected cash flow
Guarantee of asset	Sponsor assets	Project assets
Risk	More risky involving company assets	Limited to the project assets
Term of capital	Infinite term horizon	Finite – matches project life

Source: Meseko, A. A. (n.d.). Academia. Retrieved from Academia.edu. http://www.academia.edu/15087234/CORPORATE_FINANCE_VERSUS_PROJECT_FINANCE 7.2 Funding for CCUS readiness – Future-proofing investment.

CCUS readiness requires pre-investments today, aiming to future-proof the facility tomorrow. The future-proofing allows a facility not to become stranded and to adjust quickly, once regulatory and economic conditions are in place. Quite simply, the aim of building new facilities to be capture-ready today is to reduce the risk of carbon emission lock-in or to have a large stranded asset tomorrow (IEA 2010). Also, at the time of incurring additional pre-investments, the facility does not result in direct CO_2 mitigation but instead prepares itself for future CO_2 mitigation once viable economic and regulatory conditions are in place.

Ideally, no project developer would like to incur costs today without getting commensurate returns. Nonetheless, China has actively explored CCUS applications for enhanced oil recovery (EOR), which can provide additional revenue streams for the future. If executed right, such steps take the pressure off from the government to provide additional subsidies and prepare facilities to be self-sufficient. At some sub-regional levels, project developers have shown willingness to build coal-fired power plants as capture-ready as a future-proofing tool, i.e. anticipating regulatory conditions of tomorrow and preventing risks of assets becoming stranded (GCCSI 2012a).

It is expected that capture ready pre-investments will enable full-scale CCUS deployment when policy drivers support investments in CCUS technology via a commercially attractive proposition such as through carbon markets and prices. Key players in the CCUS chain, including environmental organizations and the finance community, have increasingly started to consider capture ready financing as an opportunity to deliver on a range of clean energy ambitions for the future.

Without CCUS pre-investments, there exist continued risks of long-term operations of new facilities with carbon "lock-in", a situation where plants continue to emit large amounts of CO_2 in a case where CCUS remains technically and economically infeasible due to equipment and site constraints (ICF 2010). Another potential adverse result is the emergence of "stranded assets" in which plants may be closed before the end of their planned period if the regulatory policies require facilities to opt for CCUS retrofit which plant owners cannot achieve due to technical or financial difficulties.

In term of financing, CCUS readiness projects can be funded via different sources and modes, ranging from debt to pure equity and from project finance to corporate finance to purely government-funded mode. With every new technology, however, the imperative of government funding is high, especially when the technology is nascent and private confidence is still developing. In the absence of private sector financing, there is a need for public funding to address possible market failures.

8.2.1 Why CCUS Readiness Financing Remains a Challenge

There are several reasons why CCUS readiness financing has remained a challenge. First, while several coal projects are being financed, there are very few full-scale CCUS projects that have seen completion due to existing technical, economic, regulatory, and policy barriers. With few projects reaching full-scale CCUS, the incentive to invest in pre-investments will only be seen in hindsight whether additional pre-investments are likely to materialize into a commercially viable full-scale CCUS projects of the future. In cases, where commercial deployment of full-scale CCUS remains low, the incentive to invest in capture readiness will also remain weak.

Second, the funding for pre-investments in capture readiness CCUS readiness presents a mismatch between risk and return objectives. For making facilities CCUS-ready, project developers need to incur additional pre-investments, which can become excessive if those don't translate into adequate returns. There is also a lack of regulatory and policy clarity in many countries with respect to the future of CCUS and whether it will be deployed widely across all carbon-intensive facilities (GCCSI 2015).

Third, the carbon market has not kicked off. The tradable CO_2 prices today do not reflect a viable opportunity to enter the market and retrofit CCUS readiness. In other words, the operators today lack any incentive to make capture-ready pre-investment. Trends suggest that the current market

price of carbon will not incentivize private capital to finance demonstration projects and launch a commercially viable CCUS industry. Additional mechanisms will be essential, including public funding and government subsidies and rebates (GCCSI 2005). Once retrofitted, a further penalty arises from loss in efficiency of the plant; thus, making the same unit of a product more expensive to produce.

The EU directive under Article 33 requires that the member states grant operating licenses to combustion plants with a capacity of 300 MW or more only after assessment of availability of suitable storage sites, technical and economic feasibility of transport and retrofit for CO_2 capture. In case if the assessment is positive, the authority should ensure the suitable space on the installation site for the equipment is available to capture and compress CO_2 (EU 2009). When evaluating applications for capture readiness, the Competent Authorities under the EU identified the following constraints (Climate Action 2016):

1. Restricted availability of information on the application of the CCUS technology due to limited practical experience;
2. Lack of capacity to evaluate applications;
3. Outdated sources and basis of assumptions;
4. Exclusion of key financial aspects that can improve the cost-effectiveness of CCUS projects; and
5. Failure to consider hubs and clusters for CO_2 transport.

If capture-readiness is to become mainstream, government policy support will remain essential. Eventually, the policy support should be blended with private sector capital with sound and robust technology along with healthy stakeholder communication. As a first step, to avoid future stranded assets and a CO_2 lock-in, CCUS-ready financing should incorporate CCUS readiness planning in initial design and development. From the Government's point of view, CCUS readiness financing will accelerate if a long-term agenda is defined right from the start with a phased commitment to deploy CCUS in the future. Without a long-term agenda, private sector capital will not be optimally mobilized.

8.3 Pre-Investments for CCUS Readiness

The pre-investments for a capture-ready plant will only be cost-effective when it offers a lower lifecycle cost than an alternative plant which is built without capture ready pre-investments. At the time of incurring expenditures, a capture-ready plant will initially be more expensive, in terms of capital and operating cost, with the expectation that after the retrofit, costs will be minimized through additional capex, reduction in down-time during implementation or increased efficiency or output of the retrofitted plant (IEAGHG 2007).

In all cases, the cost-effectiveness of capture ready pre-investments will be a function of several parameters including but not limited to plant efficiency before and after capture, cost of fuel, CO_2 emissions rates, time before capture is implemented, plant CAPEX, plant OPEX and discount rate. Obviously, the assumed discount rate will vary from market to market and will yield different results under different scenarios. Clearly, as the IEAGHG report points out, pre-investment will be more

attractive if retrofit is made earlier and the benefits of the pre-investment are recouped earlier when the time value of money is higher (IEAGHG 2007).

As a starting point, building a capture-ready plant costs more, because additional costs are required, but the lifecycle costs of the project will decrease if a retrofit of CCUS is subsequently undertaken. For example, it may lead to choosing a more sophisticated combustion technology than classical boilers (Ha-Duong 2017). Additional space would also need to be provided for the CO_2 capture equipment (scrubbers, CO_2 compressors, oxygen production plant etc.), and additional infrastructure including cooling water and electrical systems, safety barrier zones, pipework, and tie-ins to existing equipment (IEA 2017). Further space may also be needed during construction, for storage of equipment and materials and for access to the existing plant. Apart from additional land, further, pre-investments can be made to reduce the cost and downtime for retrofit of CO_2 capture. Some potential pre-investments apply to all technologies, including oversizing pipe-racks and making provision for expansion of the plant control system and on-site electrical distribution. These pre-investments are low cost and can result in significant reductions in the costs and downtime for retrofit (IEAGHG 2007).

Ideally, all new coal-fired power plants should be built with "capture-ready" facilities to minimize the risk of CO_2 "lock-in", but currently there are insufficient incentives and no mandatory policy to encourage capture-ready investments (apart from few examples such as PRC and UK). Even in regions with strong focus on carbon emission reductions, such as the European Union, the focus remains on pilot and demonstration projects, with the exception of Canada, where strong regulations have led to commercial-scale CCUS implementation.

The IEA has modelled capture-ready pre-investments. For cost modelling, IEA assumed that some salient features stand out for pre-investment for a capture-ready plant as compared to a plant without capture-ready pre-investments. The IEA cost analysis of plants with and without pre-investments are outlined in Table 8.2.

Table 8.2 Pre-Investments Required to Make Facilities Capture-Ready

(million US$)	Plants without capture-ready pre-investments	Plants with capture-ready pre-investments	% Difference
IGCC (509 MW)	590	620	5.08%
Post-combustion (867 MW)	1,410	1,420	0.71%
Oxy-fuel (679 MW)	647	650	0.46%

IGCC = integrated gasification combined cycle, MW = megawatt.
Source: IEA Greenhouse Gas R&D Programme (IEAGHG). 2007. "CO_2 capture ready plants", 2007/4, May 2007.

With these scenarios, the range of pre-investments required to build plants capture-ready are in the range of 0.46% - 5.08%. If the CO_2 mitigating measures are pursued, paying for the capture-ready option would act as an *insurance policy* to avoid making a plant a stranded asset in the future.

ICF (2010) also provided a detailed analysis of possible plant costs with and without capture-ready for a range of design cost options. Option 1 reflected the upfront engineering design fees associated with accommodating a post-combustion amine-based CO_2 capture system. Additional incremental costs for Option 2 reflected both the design fees and the clutch mechanism between the two low-pressure steam turbine stages. Option 3 has the largest incremental capital cost requirements as it represented the upsizing of the steam boiler and all associated downstream systems that need to accommodate larger steam and flue gas flows. The cost breakdown of the three types of power plants are summarized in Table 8.3 for a reference plant of 550 MW.

Table 8.3 Capital Cost Breakdown for Pulverized Coal Reference Plant and Amine Scrubbing Option

Pulverized Coal	$ million	% change
Not CCS-ready	866	-
Option 1	871	0.46%
Option 2	891	2.86%
Option 3	1,111	28.21%

CCS = carbon capture and storage.
Source: Authors; ICF 2010. Defining CCS-Ready: An Approach to an International definition. Fairfax: ICF.

From the ICF analysis, it is also clear that unless the project developer intends to take comprehensive capital investment measures for possible much lower retrofit costs in the future, an average costs escalation on design and front-end engineering with minor capex may remain in the range of 0.5% to 5.0%.

The incremental costs in pre-investments should be analysed in the light of expected future carbon prices of tomorrow and a broader economic and policy agenda. In many developing countries where regulators try and maintain the lowest cost tariff for consumers, spending an incremental 5% may not make much business sense. However, considering the future case of stranded assets, project developers may well be better off opting for low-cost pre-investments such as leaving extra space. Bohm et al. further reached the following conclusions (Bohm 2007):

i. The choice of making a project capture-ready will remain dependent on the cash flow models and the assumed future CO_2 price trajectory.
ii. CO_2 ''lock-in'' will remain a function of future CO_2 prices. At high CO_2 prices, all plants will lower CO_2 emissions (through retrofitting to CCUS or by shutting down). However, moderate CO_2 prices will kick-in the capture-ready concept to avoid the risk of CO_2 ''lock-in'' in the future.
iii. The longer the delay in establishing a CO_2 price after a plant is built, the higher the CO_2 price needs to be to justify the ''capture-ready'' concept.

8.4 CCUS Readiness Financing Mechanisms

As outlined above, project developer's costs to make a facility capture-ready is in the range of 0.5%-5.0% and up to 30% for making exhaustive and comprehensive investments, which will vary upon the choice of technology and location. Financiers will rationally avoid making financial pre-investments for capture-ready if they believe that they are likely to sit in "halfway" position for many years. In a GCCSI study, 17 developing countries projects were identified where the adequate pre-investment and enabling activities has been undertaken, showing that there are opportunities to realistically absorb funding in the short-term and build further momentum for large scale deployment of CCUS (GCCSI 2012b).

The following sections highlight possible financing mechanisms for CCUS readiness projects that could be undertaken with the help of public support.

8.4.1 Capital Grants

Capital grants could be offered to project developers to reimburse incremental investments in making a facility capture-ready. Incremental investments can be funded through capital grants to avoid future CO_2 lock-in. Financing mechanisms may include

- capital grants approved by the government to fund any CAPEX part;
- interest-free loans to project developers; or
- tax-free concessions on import of any machinery required in pre-investments.

8.4.2 Mandates and Standards

Regulatory instruments and technology mandates such as Renewable Portfolio Standards (RPS) for wind and solar have proved successful and could be used to incentivize CCUS readiness financing also. Governments might, for example, mandate an obligation to implement CCUS readiness for all future coal intensive project facilities. Alternately, the government might subject industries or power facilities to a GHG emission standard per unit of product. For example, a standard in the steel industry could take the form of maximum allowable tonnage of CO_2 emissions per ton of steel produced. Such standards could be set at levels to trigger CCUS readiness initially and a full CCUS value chain for future deployment (UNIDO 2010). Other prominent examples include that of the UK, where all new fossil fuel-based power plants are required to have a capture-ready study and the 2014 EU directive, where under Article 33, new investments need to be made in such a way as to facilitate a substantial reduction in emissions and require the Member States to grant operating licenses combustion plants with a rated electrical output of 300 MW or more only after the assessment of the availability of suitable storage site, technical and economic feasibility of transport facilities and retrofit for CO_2 capture (Climate Action 2016).

8.4.3 Tax Credits

Just like exploration tax credits, applicable in some countries, tax credits could be offered to project developers to ensure facilities become capture-ready. Tax credits can also be offered for long term EOR projects and CO_2 geological storage projects, prompting investments in capture-readiness today to avail any future benefits, once a firm market establishes itself. Simple amendments can be

incorporated in tax laws which can trigger capture-readiness investments. They include, for example, extending tax credits to carbon capture projects receiving $20 for each tonne of carbon captured used for enhanced oil recovery or $40 for each tonne captured and put in secure geological storage underground. Such incentives would automatically trigger capture-ready investments with project developers likely to incorporate additional revenue streams in the future by undertaking incremental investment today.

8.4.4 Dedicated CCUS Fund

A country-specific CCUS fund could be created to ensure greater R&D and making facilities capture-ready. Such a fund could be established and created at the governmental level and developed in partnership with multi-lateral donors, bi-lateral agencies as well as private sector companies. An example of such a fund already exists in the UK (DECC 2009b).

8.4.5 Premium Feed-in-Tariff

Regulators the world over have given upfront/feed-in tariffs to renewable energy technologies. The CCUS deployment levelized tariff today is almost equivalent to the tariff that regulators previously allowed for solar PV generation. Such a support can be extended to capture-ready plants with the availability of a slightly higher tariff as compared to facilities that are not capture-ready. A slightly higher capture tariff, with sites clearly identified and pre-feasibility studies completed, will raise investor interest to invest in R&D. Apart from FITs, alternate support could be providing additional hours of operation to plants that are capture-ready, which has been practised in Guangdong province of PRC.

8.4.6 Concessional Finance

Another financing mechanism to spur capture-ready plants is repayable concessional finance, such as a subordinated loan, given out by governments at lower than commercial rates. This mechanism, which is similar to a capital grant with repayment, could lower the overall cost of the project by reducing the blended cost of finance (The University of Queensland).

8.4.7 Loan Guarantees

Loan guarantees could be offered by a government to provide added security for commercial loans for newer technologies and deployment (The University of Queensland). For CCUS readiness financing, the Government can provide loan guarantees to the extent of incremental CCUS readiness investments (in the range of 1%-5%) which will incentivize project developers to take steps and invest in a CCUS readiness framework. Under a typical loan guarantee program, guarantees can be provided for up to 100% of a loan, although there is a preference that loans should not exceed 80% of the total project cost. Project developers are required to put in an equity contribution to minimize the risks and costs of the loan guarantee to the government (Al-Juaied 2010).

8.5 Other Innovative CCUS Readiness Financing Mechanisms

Apart from the financing mechanisms described above to develop CCUS readiness, two unconventional ways have been highlighted to finance CCUS readiness as below.

8.5.1 Capture-Ready Options Trading

An options market can be developed specifically to finance CCUS readiness, which can stipulate that an option holder has the right (but not the obligation) to exercise the contract to retrofit an underlying facility to capture CO_2 on or before a fixed date (Liang et al. 2010). In the future, if opportunities for EOR prospects develop, making it worthwhile to capture CO_2 and sell in the open market, the CO_2 option buyer will exercise the option to retrofit the existing facility. The buyer of the options would earn money in case if the regulatory environment in the future favours to earn a decent profit by selling CO_2 in the open market. The seller of the capture-ready options (facility owner) will receive extra cash inflow immediately, and part of the money could be spent to achieve CO_2 capture-readiness (Liang et al. 2010).

Capture option products can act as financial instruments that can allow investors, and corporate decision-makers, to partake in global warming investment products (Clarke 2006) and giving developers an *insurance policy* of having their assets not stranded in the future. It can also allow investors to benefit from returns in the CCUS market without directly investing in large carbon-emitting industries (steel, power, etc.). This would also trigger an options market that can trigger many asset classes including junk bondholders, hedge funds, pension funds and venture capital players to bet on the future regulatory environment and profit if their bets come true (with the hope that future regulatory and policy regime will make it mandatory for all facilities to opt for a CCUS retrofit). Such a case could see investors benefiting immensely and immediately.

8.5.2 Yieldcos

The U.S. National Renewable Energy Laboratory (2017) describes a yieldco as an investment vehicle that aggregates a portfolio of energy assets for which ownership shares, i.e., stocks, are sold in return. Yieldcos are subsidiaries of larger parent developers that hold and generate additional value from operating assets.

In the case of CCUS, yieldcos can sell additional shares of cumulative coal portfolio to project developers along with the first right to develop CCUS projects if and when the markets develop substantially. The first right advantage gives developers a captive means to sell completed projects and redeploy capital. Yieldcos can augment additional financing for CCUS readiness if the counter-party views that future regulations would lead to full CCUS deployment, or if there will be enough EOR or EGR opportunities to make carbon capture a profitable exercise in the future.

In this case, government policy needs to be clearly defined. If a government highlights that there is a phased mechanism towards full CCUS deployment, the yieldco will generate incremental investments as an insurance policy for capture-ready pre-investments while the project developer will purchase excess shares along with the first right to develop facilities in the future. Proceeds from an incremental share of sales can go to finance CCUS readiness projects.

Chapter 9 **Carbon Capture, Utilization and Storage Readiness in Industries—Next Steps**

Iron and steel, cement, and petroleum are process industries which form the majority of 'Hard to Decarbonize' sectors. In these industries, process-related emissions can only be curtailed with appropriate CCUS technologies.

Asia will be home to the largest greenfield projects in the steel, cement, petroleum and power industries over the next couple of decades. It is important that these greenfield facilities are made future proof from the perspective of GHG emissions by incorporating CCUS readiness.

This document is a first step towards raising awareness about CCUS readiness. CCUS Readiness is crucial for cost-effective GHG reduction. The readiness measures offer the necessary flexibility as and when the decision is taken to implement CCUS project. CCUS readiness will ensure that a facility does not become a stressed asset prematurely due to lack of opportunity to control GHG emission. In a way, this suggests that CCUS readiness should be considered an essential risk mitigation action while carrying out the financial evaluation of a project.

For the governments, the next step is to establish a regulatory framework which will create enabling environment for the greenfield capacities to be CCUS-ready. Such a framework should:

1. Be able to provide guidance to the industries on how CCUS readiness can be achieved by making provision for additional utilities like water, wastewater treatment, power, compressed air, as well as air and water pollution control equipment.
2. Guide them to take necessary permissions from the authorities dealing with each of the authorities so that the projects are 'ready' to implement the project whenever a decision is taken.
3. Be able to create a bankable document for future reference. The financial valuators can see CCS readiness as an additional environmental safeguard.

Canada, UK and EU have some interesting examples of regulations. Those interested in this field can borrow elements from existing examples to save time.

While technically, all the projects can be made CCUS-ready; it is finance which is crucial for the implementation of CCUS readiness and CCUS itself. How to finance CCUS readiness is an open question. Since actual emission reduction does not happen at the time of preparing the plant for CCUS, one needs to go for solutions outside of carbon markets to finance CCUS readiness.

Another important issue in preparation of the industry for CCUS readiness is creating a common CO_2 transport infrastructure for the industrial clusters. Initially, this may have to be financed and administered by the government through a special purpose vehicle (e.g., Carbonet project in Australia). Later on, this can be branched out as an independent corporate entity owned by the private sector. One can also take clue from the cost-sharing practice adapted by common transmission lines in the wind industry.

Last but, not the least, in – spite of remarkable progress in a number of CCUS technologies over the last decade, CCUS is still and emerging science. The readiness features mentioned in the document

are more from information available today. While deciding design of the plant, it is necessary to keep an eye on emerging technologies such as new CO_2 absorption fluids, chemical looping, fuel cell technologies like molten carbonate fuel cell or solid oxide fuel cell. Such awareness will help in putting additional flexibility as to ensure the selection of the best technologies.

Utilization of CO_2 is one of the lowest hanging fruits which should be looked separately. Technologies offering CO_2 mineralization, converting CO_2 to fuels and chemicals are now almost standardized and customized to the hard to decarbonize sectors.

Appendix A Case Study—Power: Bibiyana Natural Gas Combined Cycle Power Plant, Hobiganj, Bangladesh

Figure A.1 Bibiyana Natural Gas Combined Cycle Power Plant



Source: Summit Bibiyana Power Company Limited. Retrieved from https://summitpowerinternational.com/summit-bibiyana-power-company-limited.

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The author and Summit Bibiyana Power Company expressly state that this technical report does not imply, infer or indicate that Bibiyana power station should be, or is being considered appropriate to be CCUS-ready with post-combustion capture (PCC).

Disclaimer: Neither CO2CRC Limited nor the author bears any responsibility for using in this report the contents/pictures/data obtained from the power plant under study and both refuse all liability towards any third party in respect of its reliance upon or use of this report.

A.1 Introduction

The Bibiyana 341 MW Gas-fired Combined Cycle Power Plant was implemented by Summit Bibiyana Power Company Limited (SBPCL) in 2015. The power plant is located at 180 km northeast of Dhaka at Parkul of Nabiganj sub-district in Hobiganj District, Sylhet, Bangladesh. This is one of the largest IPP (Independent Power Producer) projects in Bangladesh. Asian Development Bank (ADB), International Finance Corporation (IFC) and Islamic Development Bank (IsDB) have provided USD 210 million financing to the project. The basic information is given in Table A.1.

Table A.1 Summit Bibiyana Power Plant

Item	Description
SPI Company	Summit Bibiyana Power Company Limited
Type of Power Plant	Combined Cycle Gas Turbine
Technology	Heavy-duty 9FA gas turbine from General Electric USA
Fuel	Natural Gas
Installed Capacity	352 MW (operational 341 MW)
Address	Parkul, Afrujganj, Nabiganj, Dist: Habiganj-3203, Bangladesh
Commercial Operation Date	Simple Cycle: 06 June, 2015 | Combined Cycle: 28 December, 2015

MW = megawatt.
Source: Summit Bibiyana Power Company Limited. Retrieved from https://summitpowerinternational.com/summit-bibiyana-power-company-limited.

This power plant consists of one (1) GE 9 FA Gas Turbine Generator, one (1) triple pressure Heat Recovery Steam Generator (HRSG) and one (1) Steam Turbine Generator.

General Electric's 9FA gas turbine is the 50 Hz gas turbine choice for large combined cycle applications. According to General Electric Power, the "key advantages of the 9FA gas turbine include its fuel-flexible combustion system and higher output performance. The 9FA gas turbine is configured with the robust Dry Low NOx (DLN) 2.0+ combustor, which is ideally suited for the diverse fuels typical of the worldwide 50 Hz power generation market. The DLN 2.0+ combustor is the industry leader in pollution prevention for 50 Hz combined cycle applications with greater than 56% efficiency achieving less than 25 ppm NOx." A typical design data of 9 FA gas turbine is given in Table A.2.

Table A.2 Performance of GE's 9 FA Gas Turbine

Output (simple cycle)	255.6 MW
Heat Rate	9,757 (kJ/kWh)
Pressure Ratio	15.4:1
Mass flow	624 kg/s
Gas exhaust temperature	609 °C

kg/s = kilograms per second, kJ/kWh = kilojoules per kilowatt-hour; MW = megawatt.
Source: GE Power Systems.

The water requirement (463 m^3/hr) of the project is supplied by the Kushiyara River. The River provides water for the cooling system and auxiliary cooling circuit, as well as for firefighting and service. The power plant water drainage system comprises systems for domestic sewage treatment, industrial waste water treatment, and storm water drainage. Treatment of the waste water is employed to meet applicable environmental guidelines (Summit Power International Limited). The water balance diagram is shown in Section A.3.4.

The project meets all environmental and social guidelines adopted by IFC, World Bank Group, ADB, and the Department of Environment (DOE) of Bangladesh. Figure A.2 shows a photo of the overview of the plant.

Figure A.2 Bibiyana Power Plant Overview



Source: Summit Bibiyana Power Company Limited.

ADB is actively involved in addressing key barriers to large-scale carbon capture, utilization and storage (CCUS) demonstration, feasibility study, environmental and social impact assessments, and monitoring of CCUS. The plant was visited on 24 September 2018 by Dr. Abdul Qader, Capture Program Manager of Australia's CO2CRC Limited by invitation from ADB to collect data for a case study of a broader study on CCUS readiness on Asia's gas-based power plants. Mr. Darshak Mehta from Asian Development Bank was also on tour. Visitors with plant engineers and managers are shown in Figure A.3.

The concept of CCUS and its necessity has been explained in the main report. Since the start of CCUS activities worldwide, the CCUS R&D has been focused on the capture of CO_2 from baseload coal-fired power plants, since these are the large stationary continuous point sources of CO_2. But currently, the impetus is on cleaner and renewable energy. This creates two-directional perspectives for fossil fuel-based power generation—either to accelerate deployment of CCUS or to, at least, make power plants CCUS-ready.

Restrictions on coal use is prompting industries to switch to gas as the main fuel for power generation. Although gas fired power plants produce lower CO_2 (350-425 kg/MWh) than the coal-fired power plants (800-1100 kg/MWh), however, the Intergovernmental Panel on Climate Change (IPCC)'s 2-degree scenario would require the implementation of CCUS eventually on all power plants to achieve deep cut of emissions. Hence, it is wise to get these new plants CCUS-ready to avoid extra

cost when it may well be mandatory. ADB has taken a visionary approach in this regard by conducting a study to see the scenarios in capture-readiness of the gas-fired power plants. So, this case study is dedicated to a newly built gas-fired power plant is Asia.

Figure A.3 Visitors with Plant Engineers and Managers



Photo by Authors.

A.2 Factors to be Considered in CCUS Readiness for Power Plants

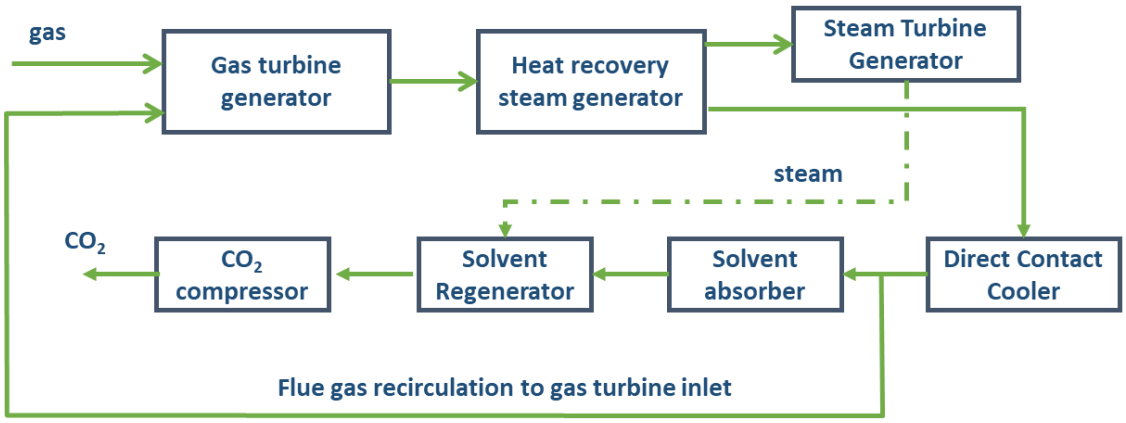
Emphasis is given on the gas-fired power plant for this case study, although most factors apply to power plants in general. The turbine flue gas from combined cycle power plants is more suitable for CO_2 capture than those from open cycle power plants. In combined cycle power plants, the hot gas turbine flue gas is passed through a heat recovery steam generator (HRSG) to raise steam for an auxiliary steam turbine power plant. The resulting cooled flue gas is suitable for post-combustion CO_2 capture. It is to be noted that IEAGHG has done an extensive study on this topic in 2012 (IEAGHG 2012).

The capture of CO_2 emissions from gas-fired power plants can be achieved by several methods, which typically are classified as either post-combustion or pre-combustion. A comprehensive analysis has given in the above report for the possible options using various capture technologies (solvent, membrane, pressure/temperature swing adsorption, cryogenics). The recommended scenario has been articulated as the option with recycling of cooled flue gas to the gas turbine inlet and post-combustion scrubbing using MEA solvent, in other words, combined cycle plant with flue gas recirculation post-combustion capture (PCC). The benefit of flue gas recirculation, when the CO_2 content is very low as in the current plant, is to increase the CO_2 content in NGCC flue gas to 7-8 % and thus provides better conditions for CO_2 capture. A block diagram of this option is shown in Figure A.4. The main components of the carbon capture are the direct contact cooler (DCC), solvent

absorber (Abs), solvent regenerator (Regen) and CO_2 compressor (Comp.). The use of LP/IP steam from the steam turbine and the flue gas recirculation options are also shown in the block diagram. So, all our discussions for the current study plant will be focussed on this particular option.

Gas turbines operate with a large excess of air, so the natural gas combined cycle (NGCC) flue gas typically has a CO_2 content of about 4% compared with the typical 12% CO_2 content of the flue gas from a coal combustion system. Because of the lower CO_2 content in an NGCC flue gas, the reaction kinetics for CO_2 capture by solvent absorption is not very favourable and this may result in larger CO_2 capture plant and higher energy plenty. In general addition of capture would reduce the thermal efficiency of an NGCC by about 7-8%, increase the CAPEX cost per kW by about 80-120% and increase the cost of baseload electricity generation by about 30-40% (I.

Figure A.4 Simple Block Diagram of Combined Cycle Plant with Flue Gas Recirculation Post Combustion Capture



Source: Authors.

The flue gas from an NGCC power plant is free from particulate material and usually has a low SO_2 content. Modern NGCC plants have efficient gas turbines fitted with new NOx burners and the NOx content in flue gas is generally less than 50 ppmv. Therefore, unlike flue gas from a coal-fired power station, further treatment of NGCC flue gas to reduce suspended particulate matter, NOx or SOx is generally not required.

The following items require consideration in the design phase of new coal or gas-fired power plant for it to be ready for CO_2 capture to be retrofitted in later years when the economic and/or regulatory environments favour. The following considerations might also be applied to existing power plants to avoid the possibility of their premature closure should retrospective CO_2 emission control eventuate.

a) Power plant configuration - enough space/footprint available to accommodate a capture facility, flue gas accessibility;

b) Flue gas cleaning facility for particulates, SOx and NOx, if required;

c) Heat integration: Energy for the regeneration of solvent used in capture technology in terms of steam requirement. This is usually accomplished using LP/IP steam available in the main power plant. Accessibility to steam extraction, boiler capacity;

d) Additional pipe rack facility inside the power plant;

e) Water treatment facility;

f) Energy penalty for the capture plant operation, which is usually 25 to 35% of the existing power plant;

g) Incentive needed to reducing CO_2 emissions/CCUS readiness (government initiatives, emission targets, pipeline corridor for transport to storage etc);

h) Analysis of risks/ barriers in implementing CCUS and related cost;

i) Comparison of cost of readiness during design stage of the power plant versus on existing power plant.

A.3 Bibiyana 341 MW Natural Gas Combined Cycle Power Plant Carbon Capture, Utilization and Storage Readiness

A.3.1 Composition of Turbine Exhaust Gas

The power plant has provided the full composition of the turbine gas exhaust from the plant, as shown in Table A.3 below. The flue gas coming out in the stack has only 3.78 vol% CO_2. This is in the first place, not a reasonable quantity to install a capture facility. It will require a large capture facility and hence higher cost is involved, which will be a deterrent factor for CCUS readiness. On the other hand, based on the plant data of 3.78 vol%, the total CO_2 emission from the plant is 35.8 kg/hr equivalent to CO_2 intensity of 378 kg/MWh. The CO_2 intensity of the plant is around 50% of the intensity for a typical coal-fired supercritical plant without CCUS. With CCUS, the CO_2 emission intensity of coal-based supercritical plant is around 100 kg/MWh. Therefore, CCUS readiness of the existing NGCC plant should be considered to make it competitive with future supercritical coal-based power plants with CCUS.

As shown in Table A.3, the SOx quantity is zero and NOx less than 25 ppm for GE 9FA gas turbine. This would ease the requirement of desulfurization and denoxing facility for the carbon capture plant. On the other hand, a slightly different picture can be derived from the CEMS (continuous emission monitoring system) data shown in Table A.4. Although very little (in ppm levels), but both SOx and NOx are present. However, these levels of SOx and NOx are well within the acceptable levels for amine-based solvents. The oxygen content in the flue gas is 12 to 14% which is much higher than a supercritical coal-fired plant (~3%). Higher oxygen in the flue gas would lead to higher oxidative degradation of the amine solvent. The flue gas recirculation will bring down the oxygen content in the gas and alleviate the situation to some extent. But we may need to take extra measures to prevent solvent degradation in the capture and hence cost reduction. However, these are not to be included during CCUS readiness activities, rather be addressed during the implementation stage.

Table A.3 Gas Turbine Exhaust Gas Composition

Turbine Exhaust Gas	Value, Vol%
Nitrogen (N_2)	72.27
Oxygen (O_2)	12.04
Moisture/water (H_2O)	11.05
Carbon dioxide (CO_2)	3.78
Argon (Ar)	0.86
Oxides of Sulfur (SOx)	0.0

Source: Information provided by Summit Bibiyana Power Company Limited Summit Centre, 18, Karwan Bazar C/A Dhaka-1215, Bangladesh during site visit in October 2018.

Table A.4 Continuous Emission Monitoring System Average Monthly Report from Heat Recovery Steam Generator (July 2018)

	SO_2	NO_X	SPM	CO	O_2	T	H
	mg/m3	mg/m3	mg/m3	mg/m3	%	°C	%
Averages	2.49	11.38	1.25	1.56	14.07	94.59	7.57
Maximum	6.25	13.29	1.41	5.50	14.15	95.10	7.80
Minimum	0.02	10.43	1.04	0.63	14.01	93.67	7.40

CEMS = continuous emission monitoring system, CO = carbon monoxide, NO_X = oxides of nitrogen, O_2 = oxygen, SO_2 = sulphur dioxide, T = temperature.
Source: Information provided by Summit Bibiyana Power Company Limited Summit Centre, 18, Karwan Bazar C/A Dhaka-1215, Bangladesh during site visit in October 2018.

The flue gas temperature should be less than 50 °C for amine-based absorption processes. According to the heat balance diagram, the gas temperature after the HRSG is 97 °C. Therefore, cooling of the gas before CO_2 absorption is needed.

A.3.2 General Layout

The plant was designed in a compact way optimising the use of the available space. While it is good for the current plant configuration, however, makes it more difficult to add ducting for flue gas recycle and equipment for carbon capture unit beside the stack. There is no space available to add capture unit.

Usually, for a 250 MW size coal-fired power plant, the footprint for the main capture equipment would require approximately 9,000 to 18,000 m^2 additional space where the CO_2 content in the flue gas is about 12%. So, for the gas turbine, flue gas with 3-4% CO_2 would require a much bigger size

footprint.[22] The flue gas entrance to the stack is also compact (Figure. A.5) meaning accessibility of flue gas and cleaning would require massive redesigning of the site arrangement.

Figure A.5 Photo of the Power Plant

(N.B. all available space is utilised, no room for capture unit)



Source: Summit Bibiyana Power Company Limited. Retrieved from https://summitpowerinternational.com/summit-bibiyana-power-company-limited.

Figure A.6 Flue Gas Entrance to the Stack

(N.B. difficult accessibility to stack gas)



Photo by Authors.

[22] See the main report section 6.4.1 and IEAGHG, 2012/8, July 2012 - Table 3 at page 11

A.3.3 Heat Integration/Availability of Steam

Heat integration aims at increasing energy efficiency in industrial processes by combining heating and cooling demands and thereby reducing the need for external heating and cooling utilities. In the CCUS process, heat integration is sought to minimise the energy penalty incurred by the capture plant. Usually, two target areas are identified: steam extraction from existing LP/IP lines and boilers. To increase energy efficiency of the process through heat integration, a new network of heat exchangers is required. The size of the network depends on the desired level of integration. As the existing plant is very compact, only a basic level of heat integration can be implemented.

Figure A.77 and A.8 indicate that there is no access to IP/LP steam available. Only the HP steam line is in the accessible space (Figure A.8). The HRSG parameters are provided in Table A.5.

Table A.5 Steam and Gas Parameters of Heat Recovery Steam Generator

Stream	Flow (ton/hr)	Temperature (°C)	Pressure (kPa(a)
GT gas exhaust	2177.6	619	104.52
HP steam	280.36	566.3	10920
MP steam	302.67	566.7	2262
LP steam	32.16	307.4	415.6
HRSG gas exhaust	2177.6	97	101.2

GT = gas turbine, HP = high pressure, hr = hour, HRSG = heat recovery steam generator, kPa(a) = kilopascal (absolute), LP = low pressure, MP = medium pressure.
Source: Information provided by Summit Bibiyana Power Company Limited Summit Centre, 18, Karwan Bazar C/A Dhaka-1215, Bangladesh during site visit in October 2018.

LP steam generated by the HRSG can be used for capture without much modifications in the steam cycle. The HBD figures in **Error! Reference source not found.** indicate LP steam generated by HRSG (32 ton/hr at 307 ^{o}C) could be utilized for the CO_2 capture process. A preliminary estimate based on over 3.6 MJ/kg of CO_2 regeneration energy requirement shows the total solvent regeneration heat requirement for capturing 90% CO_2 from flue gas is 129 MW which is equivalent to the steam requirement of 219 tonnes/hr of LP steam. Therefore, LP steam generated by HRSG will serve only a partial need (around 15-20%) for capture unit's solvent regeneration system. The additional steam LP steam for CO_2 capture can be extracted from the steam turbine, but it requires a major modification to the steam turbine. The reason for the high energy requirement for capture is due to very low CO_2 content (less than 4 vol%) in the stack gas. Hence it will be a costly exercise to add any carbon capture system in this plant.

Figure A.7 Turbine House



Photo taken by Authors.

Figure A.8 High-Pressure Bypass



Only HP by-pass and no LP/IP steam by-pass

Photo taken by Authors.

A.3.4 Water Treatment and Cooling

As mentioned earlier in the Introduction, the water requirement of 463 m^3/hr is met from the river Kushiyara which is close by. It seems there will be no issue of additional water requirement for the capture unit. Based on the preliminary estimate, to capture 90% of CO_2 from the flue gas 60 m^3/hr of additional cooling water is required. The plant has enough water treatment facility and space to redesign upward (see Figure A.0 and Figure A.2).

Figure A.9 Cooling Towers



Photo taken by Authors.

A.3.5 Extra Power

There is no extra power available to serve the capture unit. As gas turbines are the standard equipment, we do not anticipate much deviation in its performance than that suggested by its manufacturer GE. The HRSG is designed to extract maximum heat from the gas turbine exhaust gas with HRSG exit gas temperature of 97 °C. This means we cannot extract any more power from the existing plant. An additional 29 MW of power is required to meet the power requirement of CCUS auxiliary equipment like CO_2 compressor, solvent pumps, water pumps and gas fans. This means in case of CCUS, the net output from the power plant will be lower than the current value of 341 MW. To maintain the current power output with CCUS in operation, a dedicated auxiliary power source for CCUS operation is required.

Rough estimates of the characteristics of the NGCC power plant under study, in comparison to a published data on 851 MW power plant, are shown in Table A.6.

Table A.6 Rough Estimation of Parameters for the Natural Gas Combined Cycle Plant Under Study

Item	Published data for an NGCC plant of 2.44 times bigger than the plant under study	Current plant, very rough estimation With 90% Capture
Basic Parameters		
Gross Output Total, MW	850.6	352

Plant Auxiliary, MW	19.4	11
Carbon Capture, MW	45.7	29.1
Net Output	785.5	311.9
Specific Heat Duty for CO_2 Capture, MJ/kg CO_2	3.14	~3.6
Other Utilities		
Cooling Water for power plant, t/hr	21,893	9,100
Cooling water for capture, t/hr	39,785	~20,000
Raw water for power plant, t/hr	355.9	143.3
Raw water for capture, t/hr	638.9	315
LP steam for capture, t/hr	406.4	32 (available)
Demin water for power plant, t/hr	1.9	
Demin Water for capture, t/hr	7.78	
Waste generated by the power plant		
Cooling Water Blow Down, t/hr	69.14	38
Blow down from HRSG, t/hr	1.9	3.7
Waste Generated by Capture		
Cooling water blowdown, t/hr	122.8	
Amine waste, t/hr	0.9	
Condensate waste from the compressor, t/hr	5.4	
DCC condensed water, t/hr	182.3	
Economic parameters		
EPC plant cost increase for capture, %	102	~ same
LCOE increase due to capture, %	37	~ same
Cost of CO_2 avoidance, US $ (2011 price)/t CO_2	101	~ same

CO_2 = carbon dioxide, DCC = direct contact cooler, EPC = engineering procurement and construction, HRSG = heat recovery steam generator, LCOE = levelized cost of electricity, LP = low pressure, MJ/kg CO_2 = megajoules per kilogram of CO_2, MW = megawatt, NGCC = natural gas combined cycle, t/hr = tonnes per hour, US$/t CO_2 = US$ per tonne of CO_2.

Note: The figures absent in the last column need detailed engineering; hence, one can only guess from the published figures in the middle column, which is for a different size plant.

Source: IEAGHG, "CO2 Capture at Gas Fired Power Plants, 2012/8, July 2012' https://ieaghg.org/docs/General_Docs/Reports/2012-08.pdf.

A.4 CCUS Cost vs CCUS Readiness Cost

A measure of CCUS cost is in practice in terms cost of CO_2 avoided. Both CAPEX and OPEX are reflected in these costs. In the detailed study done by IEAGHG[23], the CO_2 cost for gas-fired combined cycle power plant has been estimated to be around US $101 - $112/tonne of CO_2 avoided, based on 2011 costs. However, there is a more recent estimate of US $43/tonne of CO_2 avoided[24]

[23] IEAGHG. 2012. CO2 Capture at Gas Fired Power Plants 2012/8. https://ieaghg.org/docs/General_Docs/Reports/2012-08.pdf. .

[24] GCCSI. 2017. Global Costs of Carbon Capture and Storage 2017 Update by Lawrence Irlam Senior Adviser Policy & Economics, Asia-Pacific Region, June.

From the analysis in above sections, it is clear that the plant does not meet all the criteria to be a candidate for CCUS- readiness. Due to the low content of CO_2 in the flue gas, the capture plant will be too big in size in addition to the high energy requirement (>3.6 MJ/kg CO_2), which makes any CCUS readiness in this plant not feasible. Similarly, the existing layout of the plant makes it very difficult to perform any modification in the steam turbine and IP/LP changeover. A small auxiliary steam generator and power generator could be installed to take care of the steam and power requirement for CCUS operation, but there is not much space for the installation of those units. The additional land acquisition may be a costly proposition.

Therefore, the CCUS readiness cost for this plant would be higher by order of magnitude than a differently laid out and easy to access plant, so it is not appropriate to do a CCUS costing for the plant in a case study. It would need a detailed engineering design study to quantify the cost figures, but the probable high CCUS cost for such a low carbon gas-fired power plant would not justify carrying out such a detailed study. However, if it were considered during the design stage of a power plant, it could have been much cheaper to add all the features of capture-readiness outlined in Section A.2 above. MMainly the space allocation and the provision of few access points. So, the CCUS readiness cost for the current plant would involve in purchasing required space (~ 12,000 m^2) and redesigning the connectivity for LP steam, flue gas accesses and expanding the water treatment plant.

A.5 Summarizing the Assessment of Capture-Readiness Criteria for the plant

An overall summary of the outcomes from the visit is given in Table A.7 by comparing with CCUS readiness criteria identified in Section 2.

Table A.7 Outcomes Summary

CCUS Readiness Criteria	Bibiyana Power Plant Conditions
Power plant configuration—enough space/footprint available to accommodate a capture facility, flue gas accessibility	The plant is too compact, and there is no room for the capture unit. The plant would need to acquire space for capture-readiness
Flue gas cleaning facility for particulates, SOx and NOx.	The data from the plant indicated that SOx, NOx and particulate values are negligible; however, some solvent vendors prefer to have cleaning facilities to eliminate them to avoid solvent degradation/stable salt formation.
Heat integration—energy for the regeneration of solvent used in capture technology in terms of steam requirement. This is usually accomplished using LP/IP steam available in the main power plant. accessibility to steam extraction; boiler capacity	32 t/hr LP steam can be used to serve 15% of capture energy need. There is no LP/IP by-pass line inaccessible space. A major modification in steam cycle would be required to achieve 90 % capture.
Additional pipe rack facility inside the power plant	The plant is too compact; however, if a decision is made to install a capture unit, the existing pipe racks can be used.
Water treatment facility	Current water treatment facility needs to be extended by approximately twice in size.

CCUS Readiness Criteria	Bibiyana Power Plant Conditions
Energy penalty for the capture plant operation, which is usually 25 to 35% of the existing power plant.	The energy penalty seems to be below 20%, which is a good sign for capture retrofit; however, extra caution needs to be raised due to non-existence of the space for capture unit, and also the addition of piping access will require redesigning of equipment outlets (LP, flue gas access etc.)
Incentives needed to reducing CO_2 emissions and CCUS readiness (e.g., government initiatives, emission targets, pipeline corridor for transport to storage, etc).	Although the Government of Bangladesh is committed by the Paris agreement, there is still a long way to achieve confidence in these items. But, this study would help to take further decision.
Analysis of risks and barriers in implementing CCUS and related cost	It is too early to do a proper analysis on the risks.
Comparison of cost of readiness during the design stage of the power plant versus on existing power plant	It is usually much easier to do the capture readiness during the design stage rather than in a built plant environment. Apart from the space allocation, other connections as identified above would cost an order of magnitude more if done on a built plant than in the design stage. Those costs for the current plant would obviously be higher due to its compactness.

CCUS = carbon capture, utilization and storage, CO_2 = carbon dioxide, IP = intermediate pressure, LP = low pressure, NOx = oxides of nitrogen, SOx = sulphur oxides, and t/hr = tonnes per hour.
Source: Authors.

A.6 Conclusions

The emission intensity of 378 kg CO_2/MWh of this Bibiyana NGCC plant definitely makes it a candidate for CCUS or CCUS readiness. But the space constraint at the plant makes it difficult. Moreover, due to the compact design of the plant, any modification in the steam and gas cycle that is needed for CCUS readiness will be very costly and therefore, not economically viable. However, for other NGCC plants with different configuration and layout, CCUS readiness may well be viable. So, it needs to be assessed on a case by case basis.

The important lesson from this study is that CCUS readiness is better to be considered during the design stage rather than on an already built power plant. Due to rising cost and more stringent regulations on land acquisition, the power generators are looking for a compact, and optimised design of new power plants and they will continue to do so until CCUS readiness is made mandatory for all the new plants.

Appendix B Case Study—Cement: Citeureup, Indonesia

B.1 Introduction

Total annual Indonesian clinker production was 78 Mt in 2016.[25] Indocement started their first cement factory in 1975 in Citeureup, Bogor, West Java. The Citeureup cement plant is one of the biggest cement plants in the world with current production of roughly 11 Mt/year cement clinker production. With all ten production lines running, clinker production can even be scaled up to 15 Mt/year. Nine of the production lines were built between 1975 and 1984, and the other one was built in 2016. The production capacity of each of the lines is so large that they can be compared to a complete cement plant elsewhere. Jan Theulen (Director of Alternative Resources, Heidelberg Cement) and Roberto Predonzan (HSE Manager HTC) were the official points of contact. They made a site visit and case study for the Citeureup plant possible.

Figure B.1 Preheater tower of the largest clinker production line (P14) at Citeureup.



Photo by Authors.

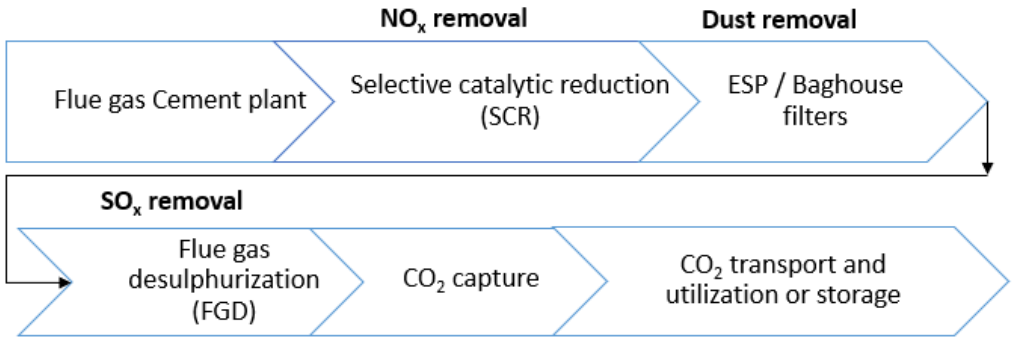
B.2 Post-combustion Carbon Capture

Post-combustion CO_2 capture is the most mature CO_2 capture technology and captures the CO_2 from the flue gas exiting the cement plant. Additional to CO_2, the flue gas also contains NO_x, dust and SO_x which

[25] U.S. Geological Survey, "Cement Production 2017," *Statistics and Information*, 2017. [Online]. Available: https://minerals.usgs.gov/minerals/pubs/commodity/cement/mcs-2017-cemen.pdf. [Accessed: 19-Jun-2018].

have to be removed before CO_2 capture (see Figure B.2). After CO_2 capture, transport and utilization or storage are other aspects to consider.

Figure B.2 Post-combustion carbon capture for cement plant flue gas



Source: Authors.

At present, there is no NOx and Sox removal applied at the Citeureup plant. Table B.1 shows the Nox, dust and Sox values for the active cement kiln lines. Removal of these components to a level below 1 ppm is essential for the amines used in post-combustion CO_2 capture, which means the addition of an SCR unit and an FGD unit, inline before a CO_2 capture facility. Dust removal, in the form of baghouse filters or ESPs, is already applied at all the kiln lines. P4 and P14 are equipped with baghouse filters which give the lowest average dust emissions. While staying within limitations of environmental standards, bursts of dust might occur at the lines equipped with ESP as a dust removal technology, which would be detrimental for the carbon capture solvent.

Citeureup provided estimations for the clinker production, flue gas volume flow, temperature, and CO_2 percentage, as shown in Table B.1.

Table B.1 Flue Gas Properties from Cement Kiln Lines in Citeureup Plant

	Unit	P4	P5	P7	P8	P11	P14
Clinker production	Tonne/day	3,000	700	5,000	5,000	8,000	10,000
Suspension preheater flue gas	[Nm3/h]	200,000	50,000	300,000	300,000	500,000	600,000
Temperature flue gas chimney	[°C]	140	130	120	120	90	110
CO_2 content	[kg CO_2/ tonne clinker]	930	1050	890	890	830	790
CO_2 composition	[vol %]	32	31	30	30	28	27
NO_x monthly average	[mg/Nm3]	<300	<500	<400	<400	<300	<300

	Unit	P4	P5	P7	P8	P11	P14
SO_x monthly average	[mg/Nm3]	<300	<100	<300	<400	<500	<500
Dust monthly average	[mg/Nm3]	<10	<50	<50	<50	<50	<5
Dust removal technology		Baghouse	ESP	ESP	ESP	ESP	Baghouse

CO_2 = carbon dioxide, kg CO_2 = kilograms of CO_2, mg/Nm^3 = milligrams per normal cubic meter, Nm^3/h = normal cubic meter per hour, Nox = oxides of nitrogen, Sox = sulphur oxides, and t/hr = tonnes per hour, vol = volume.
Source: Authors.

B.3 Cost Calculations

For calculating the cost for carbon capture equipment production line P5 was chosen for evaluation. This is the smallest of all lines at the Citeureup plant and the only one with an open area next to it. Citeureup has a very dense layout, with almost no room for expansion. For all production lines, the area for a potential carbon capture plant would have to come from sacrificing a road or shed. The P5 production line does have a small area next to it of roughly 200 m^2 shown in Figure B.33.

The cost of the carbon capture equipment and compression for P5 was evaluated with ASPEN Plus V10® and is shown in Table B.2. Additionally, it can give initial estimates for equipment cost. Pricing in version 10 of Aspen is based on a database from 2016. With the Octavius methodology, developed explicitly for economic estimates for carbon capture, equipment cost can be converted to CAPEX. Carbon capture rate of this installation would be 90% with a thermal energy requirement of 3.3 GJ/tonne CO_2. This cost estimation is only for the equipment for the carbon capture and compression up to 2.4 MPa. It does not include SCR, FGD, cooling of the CO_2, local storage, transport and storage of CO_2. CAPEX was determined according to the Octavius methodology[26].

[26] H. Kvamsdal *et al.*, "Octavius- Deliverable N ° D13 . 2 Report on methodology for benchmarking of large scale capture plants," 2015.

Figure B.3 Available area next to P5 production line which could be used for a carbon capture installation



Photo by Authors.

Table B.2 Cost for carbon capture installation for production line P5

Item	Cost ($ million)
Equipment cost	9.10
Total Direct Plant Cost	18.30
Total Indirect Plant cost	2.50
Fixed Capital Investment	20.90
CAPEX	26.10
Tons CO_2 captured/day	535

CAPEX = capital expenditure, CO_2 = carbon dioxide.
Source: Aspentech. https://www.aspentech.com/en/products/engineering/aspen-plus.

B.4 Energy for the Carbon Capture Installation

The reboiler duty for the post-combustion CO_2 is roughly 3.3 GJ/tonne captured CO_2. To supply this energy, the different options could be: -

- Local energy integration within the cement plant
- Steam import from coal combined heat and power plant.
- Natural gas-fired boiler

In this cement plant, there is no surplus thermal energy available for integration with a carbon capture installation, because the energy is already used for other purposes such as drying raw material or redirection to other processes within the cement plant. Gas from the suspension preheaters and cooler gas were evaluated as a possible energy source.

Thermal heat in the cooler gas at 300℃ is an example of a stream that was considered for local energy integration to provide energy to the reboiler of the stripper. This cooler gas cools the cement clinker product and comes out at a temperature of 300 ℃. However, in the Citeureup plant, the thermal energy is already used in the Vertical Roller Mill or redirected back to the process.

If this energy would be available, it would only be enough to capture less than 10% of the CO_2. With the value of 3.3 GJ/tonne CO_2, the theoretical amount of captured CO_2 could be calculated for each of the cement clinker production lines. Table B.3 shows the percentage of CO_2 from each of the cement production lines that can be captured using the thermal energy of the cooler gas when that cooler gas is cooled from 300 to 140 ℃. For each of the production lines under 10% of the produced CO_2 can be captured.

It is very unlikely that adaptations in the design phase of the cement plant would free up enough thermal energy for the carbon capture process. This shows the importance of a nearby power plant or another industrial facility that would be able to provide a low-quality steam source or another thermal integration.

Citeureup does not have any nearby combined heat and power plants. The nearest power plant is the Pelabuhan Ratu coal power plant, which is 90 km away. Therefore importing a low-pressure steam stream from a power plant is not an option, and an on-site natural gas boiler would have to be used. Another option would be to use alternative fuels, which are already used for the cement clinker production.

Table B.3 Thermal Energy from Cooler Gas

	P4	P5	P7	P8	P11	P14
Cooler gas [t/hr]	200	n.a.	300	300	500	700
Temperature [℃]	300	n.a.	300	300	300	300
Tonne of CO_2/hr captured with thermal energy	9.5	n.a.	13.4	14.6	14.7	19.2
% of total CO_2 stream captured with thermal energy	7.6	-	8.0	8.0	5.5	5.8

CO_2 = carbon dioxide, CO_2 /hr = CO_2 per hour, t/hr = tonnes per hour.
Source: Authors.

B.5 Storage

For applying carbon capture technology, it is essential to be able to transport and store or utilize the captured CO_2. Indonesia has a good capacity for CO_2 storage with a lot of depleted oil and gas reserves, saline aquifers and coal seams[27] [28]. The exact capacity and distribution of these storage possibilities remain to be researched and documented. For that reason, it is also difficult to assign a storage location for CO_2

[27] A. Darmawan, A. Sugiyono, J. Liang, K. Tokimatsu, and A. Murata, "Analysis of Potential for CCS in Indonesia," *Energy Procedia*, vol. 114, no. November 2016, pp. 7516–7520, 2017.

[28] D. Best, R. Mulyana, B. Jacobs, U. P. Iskandar, and B. Beck, "Status of CCS development in Indonesia," *Energy Procedia*, vol. 4, pp. 6152–6156, 2011.

from the Citeureup plant. Some potential storage locations will be near volcano and earthquake zones; therefore, their stability will need to be assessed. At present, the CO_2 storage capacity of Indonesia is estimated to be 1.4-2 Gt[29]. Indonesia does not have a legal, regulatory or financial framework in place to enable CCUS developments[30]

[29] C. P. Consoli and N. Wildgust, "Current Status of Global Storage Resources," *Energy Procedia*, vol. 114, no. November 2016, pp. 4623–4628, 2017.

[30] Best et al, 2011, ibid.

Appendix C Financial Vehicles and Activities

C.1 Funding Vehicles for Carbon Capture Utilization and Storage Projects

There are currently several dedicated CCUS funds and programs – which can be tapped for commercial CCUS financing and for those facilities that are already capture-ready. These programs have a range of focus from capacity building and pre-investment activities to large scale CCUS technology deployment. The funding vehicles and financing instruments have been elaborated from the GCCSI study of funding CCUS in developing countries.[31]

Table C.1 CCUS Funds and Programs.

Fund Name	Salient Features
Asian Development Bank (ADB) – Carbon Capture and Storage (CCS) Fund	ADB's CCS Fund supports capacity building, and scope for directly supporting demonstration projects (e.g. feasibility studies). ADB has supported CCUS activities in China, Indonesia, Philippines, Thailand, Vietnam, and Pakistan. Though the fund does not support incremental pre-investments in capture ready facilities, it supports the feasibility studies of projects, thus taking care of the technical evaluation required before proceeding with pre-investments.
Carbon Sequestration Leadership Forum (CSLF) – Capacity Development Program	The Carbon Sequestration Leadership Forum (CSLF) is a Ministerial-level international climate change initiative that is focused on the development of improved cost-effective technologies for CCS. It aims to promote awareness and champions legal, regulatory, financial, and institutional environments conducive to such technologies. The Fund is used for CCS capacity building in emerging economy members of the CSLF and could prove as a viable forum to learn about kinds of various pre-investments required and technical and engineering requisites to make facilities capture ready.
Global CCS Institute (GCCSI) – Capacity Development Program and Project Support	The Institute works with 'countries of focus' to undertake a capacity development assessment on CCUS and develop and deliver a tailored capacity development program of activities for those countries. Established and funded by the Australian Government, GCCSI can provide grants for CCS projects directly, as well as provide funding for capacity building (Almendra, 2011). The fund can be a good avenue to capture ready pre-investments by adopting learning by doing approach and learn from a range of capture readiness projects.

[31] Gobal CCS Institute. (2012). *Funding Carbon Capture and Storage in Developing Countries.* Canberra: Gobal CCS Institute.

Fund Name	Salient Features
World Bank Group – CCS Capacity Building Trust Fund	The World Bank CCS fund provides dedicated CCS Fund support focusing on capacity building and knowledge sharing, pre-investment support, and carbon asset creation services.
Clean Technology Fund (CTF)	The CTF was established to provide concessional grants and lending for the demonstration, deployment, and transfer of low-carbon technologies with significant potential for long-term GHG emissions savings. CCUS is currently not eligible for CTF co-financing. Still, a case may be made on an individual project by project basis to get capital funding from CTF, especially if there are clear prospects of EOR activities or incentives for underground CO_2 storage that can result in CO_2 mitigation as well as additional revenue streams for project developers. If there is a clear case of emissions reduction in the future, a case can be put forward to the CTF, which may allow for capture ready investments.
Global Environment Facility (GEF)	The GEF is an independent financial organization that serves as the financial mechanism for various UN conventions, providing grants for projects related to the environment, including a Special Climate Change Trust Fund that could be used for CCUS project deployment. The primary aim to GEF is to assist developing countries in fulfilling United Nations Framework Convention on Climate Change (UNFCCC) targets through grants for projects requested by host government for co-financing of policy implementation and pilot and demonstration technologies. GEF has in the past has supplied grants to CCS projects as well. The instrument includes funding for a broad set of eligible activities, including capacity building, technical assistance for "readiness" activities and technology development and transfer.
Green Climate Fund (GTF)	The GCF is being positioned to become the main global fund for climate change finance, and in time will seek to leverage additional private and public finance. The instrument focuses on a broad set of eligible activities, such as capacity building, technical assistance and technology development and transfer. CCS is explicitly stated as being eligible under the fund activities and can prove to be a good avenue for capture-ready pre-investments for suitable applications.

CO_2 = carbon dioxide, EOR = enhanced oil recovery, UN = United Nations.

Source: Global CCS Institute. (2012). Funding Carbon Capture and Storage in Developing Countries. Canberra: Global CCS Institute.

C.2 Financing Activities for CCUS Readiness Framework

Considering the context above, there is a need to identify sources for pre-investments that can lower the costs of CCUS retrofit in the future. .

Table C.2 outlines financing guidelines that governments can adopt to foster technical developments, land use patterns, and laws and regulations to foster capture-readiness pre-investments. It is expected that robust technical guidelines can help the transition to eventual CCUS with smoother, faster, and cost-effective deployment.

Table C.2 Activities and Enablers of CCUS Readiness Financing

CCUS Financing Activities	Financing Category	Financing Enabler
Stakeholder consensus and pre-feasibility studies		
Invest in technical pre-feasibility studies on capture, transportation, and storage to encourage the development of CCUS hubs.	Pre-feasibility studies	Concrete site characterization and assessment studies should be carried out for geological, environmental, operational, and financial risk assessments. Technical feasibility for right of way for transportation can alleviate concerns on pipeline financing and pre-feasibility on storage sites can ease concerns on potential storage areas– thus enhancing confidence for capture ready pre-investments and eventually leading to full-scale CCUS deployment.
Invest in economic and financial pre-feasibility studies on capture, transportation and storage and further disseminate knowledge on the economic likelihood of CCUS retrofit.	Financial and economic pre-feasibility	A financial and economic assessment can be undertaken at a high level with an aim to support project developers to accept new technology and disseminate useful knowledge. A robust pre-economic and financial assessment will most likely reflect future input prices (both absolute and relative), forecast of electricity price levels, anticipated carbon emission prices, and retrofit plant's capital and operating costs to carry out futuristic simulations and sensitivity analysis on cost curves and returns.
Formulate an inter-agency working group to consider views on costs of transport and storage, including provisions on environment, health and safety issues.	Storage and transport liability framework assessment;	Legal liability issues remain critically important for the commercial development of CCUS. To ameliorate any concerns, Governments can provide effective guidelines for pipeline rights of way and a storage liability framework that can advance investor confidence for CCUS readiness investments. Formulation of an inter-agency working group to constantly report on

CCUS Financing Activities	Financing Category	Financing Enabler
		case studies, projects, and associated costs can be a starting point for such an arrangement.
	Permitting, health, safety, and environmental issues.	CCUS projects must comply with provincial and federal laws such as environmental protection. Engaging in appropriate public engagement and consideration of health, safety, and environmental issues will pacify investor concerns on CCUS readiness financing.
Policy enablers		
Include CCUS in national climate and energy policies, elaborate on readiness financing scope, long-term R&D requirement, and associated costs.	Research and development	CCUS readiness inclusion in national energy policy and its financing scope can kick-start a conversation on newer technologies, associated R&D required, and risks involved.
Include provisions of small grants, industrial grants, and matching credits in national energy policies for CCUS readiness financing.	Financing tools for CCUS readiness financing	Government support will be an essential component in the initial deployment of CCUS readiness. Inclusion of financial incentives ranging from small grants, tax credits along with compulsory mandates and standards will provide a headway for the adoption of CCUS led technologies.
Make it mandatory for project developers to leave sufficient space on or near the site in the initial design to accommodate capture equipment in the future.	Cost of minimum land space required	With capture technologies still in the development phase, it may not be appropriate to impose full-scale comprehensive capture-readiness requirements. Project developers should, however, make a coherent justification for proposed space allocation of their chosen capture technology. Such a guideline is present in the UK laws and relies on the testimony of project developers that their site meets minimum criteria for capture readiness. Also, capture-readiness is not a one-time event, and additional pre-investments are required for management of capture-readiness throughout the life of the facility. A periodic certification from project developers that their facilities comply to minimum capture-readiness should be solicited to ensure initial pre-investments are safeguarded throughout the life of the facility.
Through stakeholder consensus, prepare robust financial capture readiness regulations such as estimates on upfront costs, government contributions available and lessons learned	CCUS readiness financing regulations	The economics of CCUS readiness is hard to separate from technical aspects. Formulation of CCUS readiness financing regulations will shed light on past projects, estimated financing requirements and modes available to finance CCUS readiness.

CCUS Financing Activities	Financing Category	Financing Enabler
regarding past capture ready transactions.		It should be the regulations intended to ensure that guidance on capture readiness is reviewed regularly to reflect both technical and economic developments and that it should be tied up with broad-based stakeholder consultation.
To make capture ready pre-investments credible, indicate a phase-wise, long term transition to full-scale CCS deployment.	Project development	If CCUS readiness financing is to become mainstream, the policy should ensure long-term commitment to deploy full-scale CCUS. For instance, by including a condition that plant permits can be revoked if full-scale CCUS is not deployed within a set timeline, it will enable project developers to invest in readiness financing today. Such a strategy is obviously associated with a degree of risk, given the difficulty of guaranteeing effective implementation and enforcement of retrofitting regulation[s] but is crucial to make current regulations more credible while also indicating a firm commitment for CCUS.
Operational enablers		
Identify and propose a suitable area for the storage of captured CO_2 which has been appropriately assessed, including detailed cost estimates. Also identify and propose realistic pipeline routes and cost estimates for CO_2 transportation.	Transport and storage enablers	Identification of realistic pipeline routes and storage areas can provide a long-term commitment to CCUS deployment and will pave the way for easier and cost-efficient technological deployment. Detailed source/sink matching can be carried out to match the nearest storage sites. Cost curves can then be ascertained with sensitivity analysis and Monte Carlo simulations can then help to analyse upper and lower ranges. For transport, it may be important to learn from the natural gas pipeline industry, various modes applicable for CO_2 transport such as pipelines, ships and off-shore methods, their respective costs assessments, and applicable experiences.
Help develop a CO_2 market that can connect captured CO_2 with storage operators / EOR opportunities.	CO_2 market development	CO_2 has various industrial application uses such as in oil and gas applications for EOR/EGR activities, firefighting applications and food and beverages industry. Coordinated efforts are required to kick-start market applications for CO_2 to encourage long term industry vertical. With a well-functioning market for CO_2, the private sector will be more inclined to invest in capture-readiness today.

CCUS Financing Activities	Financing Category	Financing Enabler
Review, monitor, and evaluate capture ready status and report on it periodically.	Periodic operational performance evaluation	An ongoing review, monitoring and evaluation of capture ready financing will keep the cost estimates current and will elaborate on learning curves for project developers.

CCUS = carbon capture, utilization and storage, CO_2 = carbon dioxide, EGR = enhanced gas recovery, EOR = enhanced oil recovery, R&D = research and development.

[a, b] Department of Energy and Climate Change. 2009. Guidance on Carbon Capture Readiness and Applications under Section 36 of the Electricity Act 1989. London: Department of Energy and Climate Change.

[c] Scottish Centre for Carbon Storage. 2008. *How ready is 'capture ready'? - Preparing the UK power sector for carbon capture and storage.* University of Edinburgh and Heriot-Watt University. http://assets.wwf.org.uk/downloads/capture_ready_ccs.pdf.

Source: Authors.

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