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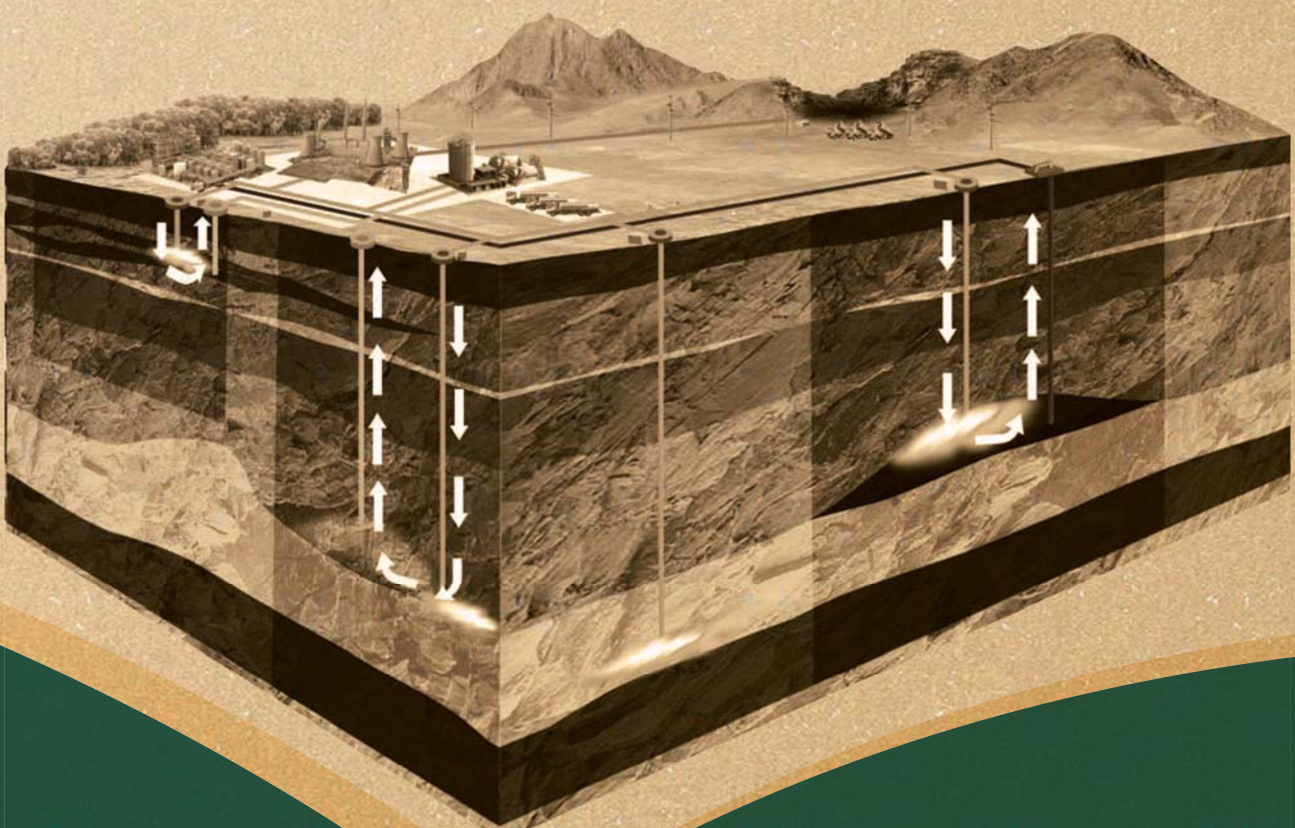
Prospects for CARBON CAPTURE and STORAGE in SOUTHEAST ASIA



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September 2013

ISBN 978-92-9254-290-0 (Print), 978-92-9254-291-7 (PDF)
Publication Stock No. RPT135683-2

Cataloging-in-Publication Data

Asian Development Bank.
Prospects for carbon capture and storage in Southeast Asia.
Mandaluyong City, Philippines: Asian Development Bank, 2013.

1. Energy and environment. 2. Climate change mitigation. 3. Southeast Asia.
I. Asian Development Bank.

Note:
In this publication, “$” refers to US dollars.

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Foreword

The crucial role that carbon capture and storage (CCS) technology could play in greenhouse gas (GHG) reduction is gaining wider international recognition. In its latest *World Energy Outlook 2011* released during the preparation of this report, the International Energy Agency projects that CCS, among a portfolio of other mitigation options, could reduce GHG abatement costs and contribute to 22% of the emission reductions needed to limit global climate temperature increases to 2°C.

The inclusion of CCS in the Clean Development Mechanism (CDM) also highlights the technology's positive role in both mitigating climate change and creating opportunities for low-carbon economic development. The successful deployment of CCS will allow countries to continue using fossil fuels while simultaneously achieving deep reductions in GHG emissions.

Several initiatives over the past 2 decades have helped to motivate the development of CCS. There are eight large-scale projects in operation around the world to date, with another seven under construction. Despite global progress on CCS, however, several challenges continue to limit its widespread deployment.

CCS faces serious challenges in developing countries due to pressing concerns regarding energy security, energy prices, technological risks, costs and capacity limitations. However, if CCS is to provide meaningful reductions worldwide, it must be increasingly put to use in developing countries where the strongest growth in fossil energy use and emissions are likely to occur.

Indonesia, the Philippines, Thailand, and Viet Nam have been selected as the focus countries for this study on CCS by the Asian Development Bank. They represent a dynamic group of economies that are projected to grow 4%–5% annually over the next decade. Such economic growth will be accompanied by high energy growth, much of which will continue to be met by fossil fuels.

The four focus countries all recognize the need to balance their energy growth with environmental stewardship. They have taken initial steps toward defining national action plans on climate change which will integrate their developmental aspirations with environmental sustainability and climate adaptation. Indonesia has gone the furthest, pledging unilaterally to achieve emission reductions of 26%, or up to 41% with international support, by 2020 against a business-as-usual scenario.

Except for Indonesia, where a role for CCS is identified in national strategy, CCS technology is not actively being considered by the other three countries. However, CCS could offer each of these countries a clear opportunity for achieving deep reductions in GHG emissions while helping to meet their growing energy demand in an environmentally sustainable manner.

Building on past CCS studies in the region, this report offers a clear actionable road map for CCS development. It identifies potential pilot projects across the four countries which could provide the basis for future demonstration and commercial-scale projects. Insights and recommendations from this study will be relevant to a wide range of stakeholders seeking to advance CCS in the region.

In the face of these challenges, I am delighted to present this report on the current state of CCS in these four dynamic countries and hope that this research can serve to accelerate the technology's future development and deployment.

James A. Nugent
Director General
Southeast Asia Department

Preface

This report was prepared by a team of national and international experts under Regional Technical Assistance (RETA) 7575 “Determining the Potential for Carbon Capture and Storage (CCS) in Southeast Asia.” The RETA was executed by the Asian Development Bank (ADB) with funding from the Carbon Capture and Storage Fund* under the Clean Energy Financing Partnership Facility.

ADB conducted the study in collaboration with the respective government agencies of the four countries: the Government of Indonesia, which delegated the responsibility of overall coordination to the Directorate General of Oil and Gas and assigned the R&D Centre for Oil and Gas Technology (LEMIGAS) to provide technical leadership; the Department of Energy, Government of the Philippines; the Department of Mineral Fuel, Ministry of Energy, Government of Thailand; and the Department of Energy, Ministry of Trade and Industry, Government of Viet Nam.

This report represents an effort to provide the initial actionable basis for CCS in Indonesia, the Philippines, Thailand, and Viet Nam. The study builds on past CCS-related work in the region and draws extensively from discussions with a wide range of stakeholders to achieve the following:

(i) Assess an inventory of emission sources to confirm that sufficient CO_2 volumes for capture are available for CCS, now and into the future.

(ii) Review geological data to estimate storage capacity and identify several high potential storage sites in oil and gas fields, together with source–sink matching that could be used to initiate CCS projects.

(iii) Analyze policy, technical, regulatory, financial, and public acceptance issues to provide a balanced coverage of the challenges facing CCS deployment, plus strategies for overcoming those hurdles.

(iv) Develop an actionable road map for CCS beginning with a pilot project in each of the four countries, which could then serve as the basis for future demonstration and commercial projects.

(v) Establish a broad-based CCS working group in each of the four countries which, if adequately integrated within government, could lead to the development of CCS in these countries.

For Indonesia, the study focused on South Sumatra. A 2009 study by the Indonesia CCS Working Group had previously recommended South Sumatra for a CCS pilot project because the region had several large sources, good sink options nearby, and an existing pipeline infrastructure. In the Philippines, the analysis converged around the provinces of CAvite, LAguna, BAtangas, Rizal, and QueZON (CALABARZON region in the vicinity of Metro Manila). The majority of sources are located in this area. For Thailand and Viet Nam, the analysis covered the whole country.

* Contributors: Global Carbon Capture and Storage Institute, and the Government of the United Kingdom.

Implementing the study recommendations will require continuing collaboration among governments, energy companies, public and private sector organizations, financial institutions, and a wide range of stakeholders both within and outside government.

We are pleased to offer this report to facilitate the understanding and promotion of CCS in Indonesia, the Philippines, Thailand, and Viet Nam.

Chong Chi Nai
Director
Energy Division
Southeast Asia Department

Acknowledgments

This report was prepared under Regional Technical Assistance (RETA) 7575 "Determining the Potential for Carbon Capture and Storage in Southeast Asia," financed by the Global Carbon Capture and Storage Institute. The Asian Development Bank (ADB) executed the RETA in collaboration with the following government agencies:

- **Government of Indonesia:** National Development Planning Agency (BAPPENAS), Directorate General of Oil and Gas (DGMIGAS), Ministry of Energy and Mineral Resources
- **Government of the Philippines:** Department of Energy
- **Government of Thailand:** Department of Mineral Fuels, Ministry of Energy
- **Government of Viet Nam:** Department of Energy, Ministry of Trade and Industry

Pradeep Tharakan (Climate Change Specialist, Energy Division, Southeast Asia Department [SERD], ADB) initiated and provided guidance and technical advice for this report. Maria Cristina Pascual (Consultant, ADB) served as the RETA Coordinator. Minnie Sarah Ramas (Project Analyst, Energy Division, SERD) and Wema Pacano (Senior Strategy and Policy Assistant, Strategy, Policy and Interagency Relations Division, Strategy and Policy Department) provided administrative support during the implementation of the RETA.

A team of national and international experts contributed to the development of this regional report and four confidential country reports for Indonesia, the Philippines, Thailand, and Viet Nam. The national teams consisted of experts from the following:

- **Indonesia:** PPPTMGB LEMIGAS, DGMIGAS, and KNI-WEC, PT PERTAMINA EP (PEP), BPMIGAS. The Ministry of Environment (MENV) also endorsed relevant parts of the report.
- **Philippines:** University of the Philippines—Geoscience Foundation, Inc., and De La Salle University
- **Thailand:** Joint Graduate School of Energy and Environment, King Mongkut's University of Technology, and Chulalongkorn University
- **Viet Nam:** Institute of Energy, and Viet Nam Petroleum Institute

Kelly Thambimuthu (Consultant, ADB) served as the international team leader providing overall direction across the entire report. Douglas Macdonald (Consultant, ADB) was the earlier team leader and conducted the initial country analysis for the four countries.

William D. Gunter (Consultant, ADB) led the geology, storage, and source-sink matching analysis and contributed significantly to the overall report, including the development of the road map. Pei Xiaodong (Consultant, ADB) conducted the economic analysis. Craig Hart (Consultant, ADB) conducted the legal and regulatory analysis. Rick Hasselback (Consultant, ADB) and Mike Clarke (Consultant, ADB) also contributed to the report.

Karthik Ganesan (Consultant, ADB) contributed to the background and analysis of financing options, and assisted in the editorial process. Jia Li (Consultant, ADB) developed the section relating to the background on CCS technology. Rachel Salazar (Consultant, ADB) and Maura Lillis (Consultant, ADB) served as copy editors and Paul Jersey Leron (Consultant, ADB) developed the cover and illustrations. Bishal Thapa (Consultant, ADB) served as the lead author.

Support from ADB's Department of External Relations for the editing, proofreading, and layout of this report is gratefully acknowledged.

Nomenclature

CO_2 avoided is the CO_2 emissions captured and stored, calculated relative to the emissions anticipated from a "business-as-usual" reference plant of the same net capacity that has not been equipped with carbon capture and storage (CCS), and therefore without accounting for increased emissions generated from the energy penalty and efficiency losses due to CCS. The amount of CO_2 avoided by a fossil fueled-plant is hence always less than the amount of CO_2 physically captured and stored.

CO_2 captured is the CO_2 emissions physically captured and stored by a CCS-equipped plant, taking into account the increased emissions generated from the energy penalty and efficiency losses due to CCS. The amount of CO_2 captured and stored is always more than the calculated value of the CO_2 avoided emissions.

Efficiency factor is a multiplier having a value between 0 and 1, which is applied to downgrade storage capacities due to uncertainties created by not considering the mobility and buoyancy of CO_2, and heterogeneity, water saturation, aquifer strength, and permeability of the storage reservoir during injection of CO_2. These uncertainties are often neglected in high-level storage due to lack of data.

Formation volume factors are the ratio of the volumes of oil and gas in the reservoir to the production volumes of oil and gas at the surface.

Gross national income (GNI) is gross domestic product (GDP) less net taxes on production and imports, less compensation of employees and property income payable to the rest of the world, plus the corresponding items receivable from the rest of the world.

Lead is a structure which may contain hydrocarbons.

Levelized cost of electricity (LCOE) represents the all-in cost for electricity generation in dollars per megawatt-hour ($/MWh). The term delta LCOE is also often used in the text to denote the difference between the LCOE of a plant with CCS and without CCS.

Net CO_2 injected is the purchased CO_2, while gross CO_2 injected is purchased CO_2 plus recycled CO_2.

Net/Gross is the volume of sandstone to sandstone plus shale over a defined subsurface volume.

Ophiolite is a section of the Earth's oceanic crust and the underlying upper mantle that has been uplifted and exposed above sea level and often emplaced onto continental crustal rocks.

Play is a particular combination of reservoirs, seals, source, and traps associated with a hydrocarbon accumulation that can be broken down into potential leads and prospects once the appropriate data are collected. A play may be considered proven if petroleum accumulations are known to have resulted from the operation of the geological factors that define the play. In unproven plays, there is some doubt as to whether the geological factors actually do combine to produce a petroleum accumulation. The geographical area over which the play is believed to extend is the play fairway.

Prospect is a lead that has been fully evaluated and is ready to drill.

Recovery, estimated ultimate (EUR) are those quantities of petroleum that are estimated on a given date, to be potentially recovered from an accumulation, plus those quantities already produced. It is the sum of the estimate of proved reserves at a specific time and cumulative production up to that time.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by the application of development projects to known accumulations from a given date forward under defined conditions.

Reserves, 1P are the proved reserves having a 90% probability that the quantities of petroleum recovered will actually equal or exceed the estimate. Denotes the low estimate scenario of reserves.

Reserves, 2P are the sum of the proved and probable reserves having a 50% probability that the quantities of petroleum recovered will actually equal or exceed the estimate. Denotes the best estimate of reserves.

Reserves, 3P are the sum of the possible, probable, and proved reserves having a 10% probability that the quantities of petroleum recovered will actually equal or exceed the estimate. Denotes the high estimate of reserves.

Reserves, possible are those additional reserves which, by analyzing geoscience and engineering data, are less likely to be recoverable than probable reserves.

Reserves, probable are those additional reserves which, by analyzing geoscience and engineering data, are less likely to be recovered than proved reserves.

Reserves, proved are those quantities of petroleum, which, by analyzing geoscience and engineering data, can be estimated with a reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

Reserves, unproved are based on geological and/or engineering data similar to those used in the estimation of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves from being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Resource is intended to cover all quantities of petroleum (recoverable and unrecoverable) naturally occurring within a volume of the Earth's crust, both discovered and undiscovered.

Water, aquifer is a layer of porous substrate (unconsolidated or consolidated) that contains and transmits groundwater.

Water, connate is the water trapped in the pores of a rock during its formation.

Water, formation occurs naturally within the pores of rock. Water from fluids introduced to a formation through drilling or other interference, such as mud and seawater, does not constitute formation water. Formation water, or interstitial water, might not have been the water present when the rock originally formed.

Water, groundwater is water located beneath the ground surface in soil or rock pore spaces or in the fractures of rock.

Water, potable is low salinity water (typically less than 3,000 parts per million), pure enough to be consumed or used with low risk of immediate or long-term harm.

Water, saline aquifer is a deep underground rock formation composed of permeable materials and containing highly saline water (typically greater than 10,000 parts per million).

Water, saline formation is a deep saline aquifer.

Wholesale power price in this report is used to denote the revenues that the generators receive for the electricity they sell.

Abbreviations

AAPG	American Association of Petroleum Geologists
ADB	Asian Development Bank
AFD	Agence Française de Développement
AMDAL	Analisis Mengenai Dampak Lingkungan (Analysis of Environmental Impact, Indonesia)
APEC	Asia-Pacific Economic Cooperation
ASEAN	Association of Southeast Asian Nations
BAPPENAS	Badan Perencanaan dan Pembangunan Nasional (National Development Planning Agency, Indonesia)
BAU	business as usual
BPHMIGAS	Badan Pengatur Hilir Minyak dan Gas Bumi (Indonesian Executive Agency for Downstream Oil and Gas Activity)
BPMIGAS	Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi (Indonesian Oil and Gas Upstream Regulatory Body)
CALABARZON	CAvite, LAguna, BAtangas, Rizal, and QueZON (Philippines)
CAPEX	capital expenditures
CBM	coal bed methane
CCS	carbon capture and storage
CDM	Clean Development Mechanism
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DENR	Department of Environment and Natural Resources (Philippines)
DGMIGAS	Direktorat Jenderal Minyak dan Gas Bumi (Indonesian Directorate General of Oil and Gas)
DMF	Department of Mineral Fuels (Ministry of Energy, Thailand)
DOE	Department of Energy (Philippines)
DoLE	Department of Labor and Employment (Philippines)
ECBM	enhanced coal bed methane
EGR	enhanced gas recovery
EIA	environmental impact assessment
EOR	enhanced oil recovery
ERAV	Electricity Regulatory Authority of Viet Nam
ERC	Energy Regulatory Commission (Thailand)
EUR	estimated ultimate recovery
EVN	Electricity of Viet Nam
FVF	formation volume factor
GDP	gross domestic product
GHG	greenhouse gas
GNI	gross national income
ICCTF	Indonesian Climate Change Trust Fund
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas R&D Program
IGCC	integrated gasification combined-cycle
IPCC	Intergovernmental Panel on Climate Change

LCOE	levelized cost of electricity
LEDFF	Low-Emission Development Financing Facility
LEMIGAS	Lembaga Minyak dan Gas Bumi (Indonesian Research and Development Center for Oil and Gas)
LNG	liquefied natural gas
LSIP	large-scale integrated project
LULUCF	land use, land-use change, and forestry
MEMR	Ministry of Energy and Mineral Resources (Indonesia)
MENV	Ministry of Environment (Indonesia)
MMV	measurement, monitoring, and verification
MoE	Ministry of Energy (Government of Thailand)
MoIT	Ministry of Industry and Trade (Viet Nam)
MoL	Ministry of Labor (Viet Nam)
MoNRE	Ministry of Natural Resource and Environment (Viet Nam)
NCR	National Capital Region (Philippines)
NGCC	natural gas combined-cycle
NTP-RCC	National Target Program to Respond to Climate Change (Viet Nam)
O&M	operation and maintenance
OGIP	original gas in place
OOIP	original oil in place
PDP	Power Development Plan (Thailand)
PEP	PT PERTAMINA EP (Indonesia)
PICCS	Philippine Inventory of Chemicals and Chemical Substances
PSC	production-sharing contract
PTT	PTT Public Company Limited (formerly the Petroleum Authority of Thailand)
PV	Petrovietnam (Viet Nam)
RAN-P	National Action Plan Addressing Climate Change (Indonesia)
RETA	regional technical assistance
SCPC	supercritical pulverized coal
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
STP	standard temperature pressure
TPP	thermal power plant
UNFCCC	United Nations Framework Convention on Climate Change
USDOE/NETL	United States Department of Energy/National Energy Technology Laboratory
Vinacomin	Viet Nam National Coal-Mineral Industries Group
WACC	weighted average cost of capital
WPC	World Petroleum Council

Units and Conversion Factors

bbl	–	barrel of oil or water (0.159 m^3)
Bt	–	billion ton*
CO_2 density	–	1.847 kg/m^3 at STP
Gt	–	gigaton (10^9 metric tons = 1 Gt)*
GW	–	gigawatt
GWh	–	gigawatt-hour
kg	–	kilogram
kg/m^3	–	kilogram per cubic meter (measurement for density)
km	–	kilometer
kWh	–	kilowatt-hour
m	–	meter
m^3	–	cubic meter
Mt	–	megaton (10^6 metric tons = 1 Mt)*
Mtoe	–	million tons of oil equivalent*
MW	–	megawatt
MWh	–	megawatt-hour
ppm	–	part per million
scf	–	standard cubic feet (ft^3) (0.028 m^3)
STP	–	standard temperature and pressure (60°F and 1 atm or 15°C and 1 bar)
t	–	1 metric ton (1,000 kg)*
Tcf	–	trillion cubic feet
TWh	–	terawatt-hour (10^9 kWh)
yr	–	year

* Please note that "1 ton" denotes "1 metric ton," both of which denote "1,000 kilograms."

Executive Summary

Carbon capture and storage will play a key role in greenhouse gas mitigation.

Projections show that by 2035 carbon capture and storage (CCS), among a portfolio of abatement options, has the potential to deliver 3.5 gigatons (Gt) of greenhouse gas (GHG) reductions. This would represent 22% of the global requirement to limit temperature increase to 2ºC, according to the *World Energy Outlook 2011* published by the International Energy Agency (IEA).

CCS is the only technology that can achieve deep GHG emission reductions from fossil fuel use in power plants, fuel processing facilities, and industries, while also minimizing overall portfolio costs of abatement options identified in the IEA's 2011 outlook.

Expected growth in natural gas production and power generation also affords greater opportunities for CCS deployment. IEA projects that natural gas consumption will grow from 2,539 million metric tons of oil equivalent (Mtoe) in 2009 to 3,928 Mtoe in 2035, accounting for 23% of the global energy mix by 2035. Natural gas processing during production offers one of the lowest cost options for CCS and is often coupled with access to carbon dioxide (CO_2)-enhanced oil recovery (EOR), which could additionally help defray the cost of CCS.

Carbon capture and storage deployment must be accelerated to achieve the kind of reductions envisioned by the International Energy Agency.

The CCS process involves four stages:

(i) capture: includes capture, dehydration, and compression of CO_2;
(ii) transport: CO_2 transport by tankers, pipeline, or ship to a storage site;
(iii) storage: injecting CO_2 for secure and permanent storage; and
(iv) measurement, monitoring, and verification (MMV): ensures secure and permanent storage.

Though several of its process components are available and proven for commercial deployment, CCS technology faces a number of risks and challenges. Large-scale, cost-effective, and integrated CCS technologies bringing together capture, transport, and storage have yet to be commercially demonstrated in power generation applications. Rather, CCS is currently being applied mainly in large natural gas–processing facilities in Africa, Europe, and North America.

CCS may be an expensive abatement option with high financing hurdles, but it is cost-competitive with some other low-emission technologies when compared without subsidy support. Currently, only seven commercial-scale projects are in operation, eight are under construction, with many more smaller pilot scale projects in operation as well. Globally, a total of 74 projects are at different stages of consideration. The pace of current development and the projected importance of CCS in delivering emission reductions clearly underline the need for renewed effort on the technology.

Much of the CCS effort to date has been limited to developed countries. To emerge as a meaningful part of the global GHG emissions abatement strategy, CCS must be deployed in developing countries where some of the highest growth in energy use and emissions are likely to occur.

Carbon capture and storage offers an opportunity for balancing economic growth and continued fossil fuel use with emission reductions in Southeast Asia.

Indonesia, the Philippines, Thailand, and Viet Nam—the four focus countries of this study—collectively represent a dynamic group of economies. These countries are among the fastest-growing economies in the world, and are well situated for that growth to continue.

Rapid economic growth and development, increased industrialization, and improved energy access have led to strong growth in the energy demand of these countries. Excluding the Philippines, the three other countries posted a 4%–5% annual growth in energy use over the last decade (2000–2010). Together, the four countries reached over 300 Mtoe by 2010: Indonesia (157 Mtoe), the Philippines (35 Mtoe), Thailand (60 Mtoe), and Viet Nam (50 Mtoe). Demand for energy is likely to continue growing at these levels.[1]

Much of the increase in energy use in these four countries over the last decade has been met through the use of fossil fuels, which currently account for around 90% of their collective commercial energy supply. Their continued reliance on coal and natural gas to meet their growing energy needs is expected to persist into the future.

Coal demand will be met through increased domestic production and imports of high-quality thermal coal that is better suited to high-efficiency supercritical pulverized coal (SCPC) power plants. Many of these new SCPC power plants, which use higher pressure and temperatures than subcritical power plants to produce electricity at a higher efficiency, offer promising opportunities for CCS.

Indonesia and Viet Nam are likely to witness significant increases in natural gas production to service their growing domestic demand and also to facilitate gas exports to neighboring countries. Many of the new fields that will come into service are expected to have a high CO_2 content in the gas. Production from these fields will require associated natural gas processing stations to strip the CO_2 before sale. These natural gas–processing stations not only offer low-cost CO_2 capture sources, but are also close to depleting oil fields, which could extend the opportunity for additional revenues through CO_2-enhanced oil recovery.

The four focus countries of this study are all acutely aware of rising GHG emissions. They have begun to make concerted efforts to reduce GHG emissions through domestic action and international climate negotiations. Indonesia has adopted the National Action Plan Addressing Climate Change (RAN-P) and pledged to achieve 26% reductions in emissions by 2020 from business-as-usual projections, or up to 41% with international support. The other three countries all have national climate strategies in place that broadly emphasize promoting energy efficiency, renewable energy, biofuels, climate adaptation, and transitioning to a low-carbon economy in the context of their development needs.

Indonesia has formally recognized CCS as a prospective technology, but in the remaining three focus countries, CCS is not explicitly discussed in the national climate response plans. The technology could therefore also be a meaningful addition to the national plans for the Philippines, Thailand, and Viet Nam.

The study addresses information gaps, identifies pilot projects, and offers an actionable road map for carbon capture and storage development.

Prepared in collaboration with the respective governments, this study has been designed to overcome existing information gaps and provide the basis for supporting long-term action on CCS in Indonesia, the Philippines, Thailand, and Viet Nam. A team of international experts, working closely with local experts, conducted the research and analysis. The analysis incorporates the views of a wide range of stakeholders collected through interviews and in-country workshops while also building on past CCS studies in the region.

The key objectives of the study were to

(i) establish an inventory of CO_2 emission sources and select the most promising sources for capture;

(ii) estimate storage potential and identify the best storage options;

(iii) match source–sink for potential CCS projects;

[1] The Philippines is set to witness an annual growth of nearly 3.4%, through 2030, more than doubling its energy consumption as compared to 2002 levels (APEC 2006).

(iv) identify pilot projects for implementation;

(v) propose an actionable road map for CCS development; and

(vi) develop an internal network of agencies and personnel (CCS Working Group) in each country which could provide leadership on CCS development.

The study focused on South Sumatra (Indonesia), five provinces around Metro Manila (Philippines), Thailand, and Viet Nam.

This study has built off previous research on CCS in the region to identify and evaluate particularly promising sites for CCS deployment.

In Indonesia, it had been previously determined that South Sumatra possessed several attributes well suited to CCS (e.g., abundant large CO_2 point sources, opportunities for storage, and existing oil and gas infrastructure) and that South Sumatra could serve as a region of focus for CCS. Despite this geographic focus, several insights and recommendations of the study will be relevant broadly across Indonesia. In addition, some specific capture and storage sites in Indonesia could not be evaluated, or underwent limited evaluation, because specific data for those sites or storage options were not available.

The analysis of the Philippines evaluated CO_2 capture potential of major stationary sources in the CAvite, LAguna, BAtangas, Rizal, and QueZON (CALABARZON) region. CALABARZON is an acronym for the five provinces in the immediate vicinity of the National Capital Region (NCR) or Metro Manila. CO_2 emissions from this relatively compact geographic region contribute a disproportionately large share of the total energy-based GHG emissions of the entire country. This study identified potential storage locations in the vicinity of the capture locations, although sources and storage potential across the Philippines are also broadly discussed.

All of Thailand and Viet Nam were assessed for CCS opportunities.

Annual inventory of 200 million metric tons of CO_2 emissions from existing sources confirms that sufficient capture streams are available for carbon capture and storage.

The inventory of CO_2 from existing sources returned a total of 214 million metric tons (Mt) of CO_2 emissions annually: South Sumatra, Indonesia (8 Mt); CALABARZON, the Philippines (17 Mt); Thailand (120 Mt); and Viet Nam (69 Mt). The largest parts of the inventory came from Thailand and Viet Nam, simply because the study covers all of Thailand and Viet Nam yet only select parts of Indonesia (South Sumatra) and the Philippines (CALABARZON).

This sizable inventory is dominated by emissions from coal and gas power plants, though some smaller sources, such as fertilizer plants, may also offer interesting capture opportunities for the stream of pure CO_2 produced for fertilizer manufacture. Although natural gas processing–facilities represent only 3 million metric tons per year (Mt/yr) total, these facilities offer the best early pilot opportunities for capture because of the lower incremental cost of capture, the proximity to storage sites, and the availability of existing transport infrastructure.

The study also evaluated potential future sources as much as possible, although details of future plants were often limited. Nevertheless, the study indicates that future power plants represent strong candidates for capture. Viet Nam expects to add 48 gigawatts (GW) of new power plants by 2025; Thailand projects it will add 9.4 GW by 2020; and the Philippines plans to add 2.2 GW by 2020. Other important potential future sources, particularly in Viet Nam, include future natural gas–processing facilities which will be necessary due to the new high-CO_2-content gas fields expected to enter production.

Natural gas processing and power plants emerged as the best capture sources.

Not all of the units identified in the inventory discussed above were ranked for capture suitability. A two-stage ranking process was used to order sources by capture suitability. The first step involved qualifying criteria that the plant had to meet to advance to the second stage of evaluation. In the second stage, plants were scored against 11 criteria measuring their suitability for capture.

Across the four countries, 36 sources with total annual CO_2 emissions of almost 140 Mt were ranked for capture suitability. Indonesia had 5 sources (6 Mt); the Philippines, 4 sources (10 Mt); Thailand, 22 sources (70 Mt); and Viet Nam, 5 sources (53 Mt). Only Viet Nam included future plants in its ranked sources. Viet Nam's inventory of existing sources revealed that future power plants offer better capture opportunities than existing units, and that existing coal-fired units would need significant upgrade and renovation for capture.

The top three candidate sources that received the highest score for capture suitability are listed in Table 1.

Natural gas processing emerges as the best capture source for Indonesia and Thailand. No such opportunities are available in the Philippines. Although not included in this list, future natural gas–processing facilities in Viet Nam could be an important source for capture in the country. Currently in Viet Nam, existing natural gas–processing facilities do not strip CO_2, relying instead on the blending of low-CO_2-content natural gas streams to meet specifications in the natural gas sold to market. As existing fields are depleted, the country will move toward production from new gas fields involving natural gas with a higher CO_2 content. The gas-processing facilities to be subsequently built to strip the CO_2 will afford a lower incremental cost, high volume, and high purity CO_2 stream that is highly amenable to capture and storage.

Coal and natural gas power plants were the other identified set of leading candidates for capture. All four countries have existing and future plants that could be used for capture, and the analysis undertaken indicates that natural gas combined-cycle power plants are the more favorable option for CCS compared to coal.

With an estimated 54 gigatons of storage capacity, the study confirms that the four countries in Southeast Asia assessed for storage have sufficient capacity to sequester CO_2.

The study finds that the four countries have CO_2 storage capacities of approximately 54 Gt, enough to store the entire initial regional inventory of 207 Mt CO_2/year (yr) for over 2 centuries. Of the estimated storage capacity, 88% is located in saline aquifers, as illustrated in Figure 1. However, this estimate carries large uncertainty since the storage capacity for saline aquifers is for theoretical storage, whereas the oil and gas storage estimate is for effective storage (see legend to Figure 1).

Table 1 **Top Three Candidates by Country**

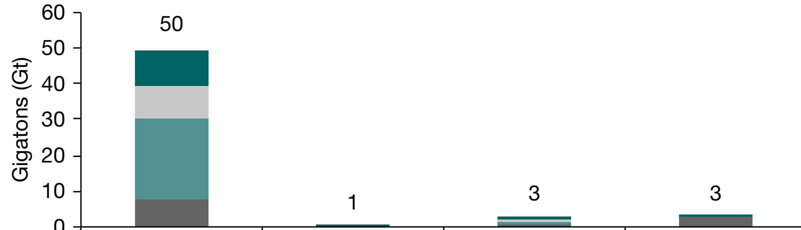
Country	Location	Plant Type	Emissions (Mt CO_2/yr)
Indonesia (South Sumatra)	South	Natural gas processing	0.1
	South	Subcritical pulverized coal power plant	1.8
	South	Fertilizer (urea) plant	2.7
Philippines (CALABARZON)	Batangas	Natural gas combined-cycle	1.4
	Batangas	Natural gas combined-cycle	3.1
	Batangas	Natural gas combined-cycle	2.8
Thailand	Central	Natural gas processing	2.0
	South	Natural gas processing	0.9
	Central	Supercritical coal (bituminous) power plant	3.1
Viet Nam	Dong Nai Province*	Natural gas combined-cycle	2.2**
	Binh Thuan Province	Future plant (2013–2016), subcritical domestic coal power plant	15.2**
	Ha Tinh Province	Future plant (2012), subcritical domestic coal power plant	4.0**

Mt CO_2/yr = million tons of carbon dioxide per year; CALABARZON = CAvite, LAguna, BAtangas, Rizal, and QueZON.

* In November 2011, a unit in the facility started up subsequent to the CO_2 source evaluation conducted for this study. That unit would also be a likely candidate for CO_2 capture.

** Projected emissions in 2015.

Figure 1 **Estimated CO_2 Storage Capacity**



	Saline Aquifers (Theoretical Capacity)	Oil Fields (Effective Capacity)	Gas Fields (Effective Capacity)	Coal Bed Methane (Theoretical Capacity)
Viet Nam	10.4	0.6	0.7	0.5
Thailand	8.9	0.1	1.3	–
Philippines	22.7	0.0	0.3	–
South Sumatra (Indonesia)	7.7	0.1	0.8	2.7

Note: Theoretical storage capacity represents the maximum possible pore space in the storage unit that CO_2 could occupy without regard to accessibility. Effective capacity takes into account the physical attributes of accessibility of the storage units and is a smaller measure of storage than theoretical capacity. Saline aquifer and coal bed methane represent theoretical storage capacity; oil and gas fields represent effective storage capacity. Coal bed methane was not evaluated for Thailand and the Philippines.

Source: ADB analysis.

Although the estimated theoretical storage capacity in saline aquifers is large, their total theoretical storage capacity could be much larger. This number is only a minimum estimate of the storage potential since there were not enough data to develop saline aquifer storage estimates for all the sedimentary basins.

Oil and gas fields represent the best starting point for storage. Many of these fields offer the potential for incremental oil production through CO_2-EOR. Relative to other storage options, the storage characteristics of these fields are better understood and the capacity estimate is the least uncertain. These fields contain sufficient storage capacity to handle all CCS projects in these countries over the next 25 years except for the Philippines. Many of these fields offer opportunities for CO_2-EOR, which could be used to defray the cost of CCS.

Unlike regional saline aquifers, where each sink option is typically large (often greater than 200 Mt CO_2, and sometimes even exceeding 1 Gt), storage capacity in individual oil and gas fields is much smaller. Around 85% of the oil fields assessed for CO_2 storage will each hold less than 10 Mt CO_2. Gas fields, on the other hand, offer a wider dispersion of storage sites by CO_2 storage volume.

A total of 143 oil and gas fields offering 3.5 gigatons of CO_2 storage capacity were ranked for storage suitability.

Oil and gas fields represent the best initial storage option. Using a two-stage ranking process, 143 oil and gas fields were screened and evaluated to identify the best storage options in each country. The first stage screening involved qualifying criteria, which established minimum thresholds on size, injection rate, depth, seal, and faults. Fields had to meet these qualifying criteria to be evaluated in the second stage of the ranking process.

The second stage assigned points against a range of characteristics to determine an overall score for judging the storage suitability of the site. The storage potential ranked according to suitability for storage is illustrated in Figure 2, based on a scoring system with a maximum value of 100. Scores were calculated based on capacity, injectivity,

Figure 2 **Estimated CO_2 Storage Capacity in Oil and Gas Fields**

Mt = megaton.

Note: In the Philippines, only three sinks passed through to the second stage of the ranking process. Given the limited number of storage sites, these sinks were not ranked for suitability of CO_2 storage as was done for the other three countries.

confinement, contamination, and economics. Based on these scores, the fields were then grouped into best, medium, and low rankings for CO_2 storage suitability.

In **South Sumatra (Indonesia)**, three of the four highest-scoring fields, representing about 28 Mt CO_2, are oil fields with potential for incremental oil production from EOR. The third-ranked option is a gas field with 488 Mt storage capacity. The reason that none of the fields fit into the top ranking was due to the relatively small size of the oil fields and the lack of injectivity data.

In the **Philippines**, only three fields met the qualifying criteria. A detailed ranking of these three fields was not exhaustively conducted due to lack of data. A large oil and gas field with a potential storage capacity of 251 Mt CO_2 emerged as the best site. However, this field will not be available for storage for another 2 decades.

Thailand's top five oil and gas fields best suited for CO_2 storage could store as much as 572 Mt CO_2.

In **Viet Nam**, the largest single volume site has an estimated storage capacity of 357 Mt CO_2 with 200 production wells and could be immediately available for EOR. Viet Nam's top three ranked fields all offer opportunities for incremental oil production.

For each of the four countries, the study identifies a proposed pilot project that is designed to lead into demonstration and commercial projects.

Following the previous capture and storage analysis, the study identifies potential CCS projects by matching sources to sinks. Source–sink matching is an essential part of the early planning process for CCS deployment.

Although a commercial project will chronologically follow the pilot and then demonstration phases, potential commercial opportunities should be kept in mind from the earliest pilot phase, and selecting a pilot site should be motivated by the commercial opportunities that exist. A pilot project is intended to yield valuable information that will allow various conditions to be predicted, in turn aiding the development of larger demonstration or full-scale commercial operation. It is essential that the same storage site be used from the pilot to the commercial stages of operation.

The source–sink match for a pilot is established by first determining promising commercial scale source–sink pairs. Once that determination is made, the pilot can be designed using the sink chosen for the commercial-scale project, but with the least expensive source of CO_2 irrespective of its long-term capture potential. Once the pilot is successful, the demonstration project can then use CO_2 captured from the commercial capture source.

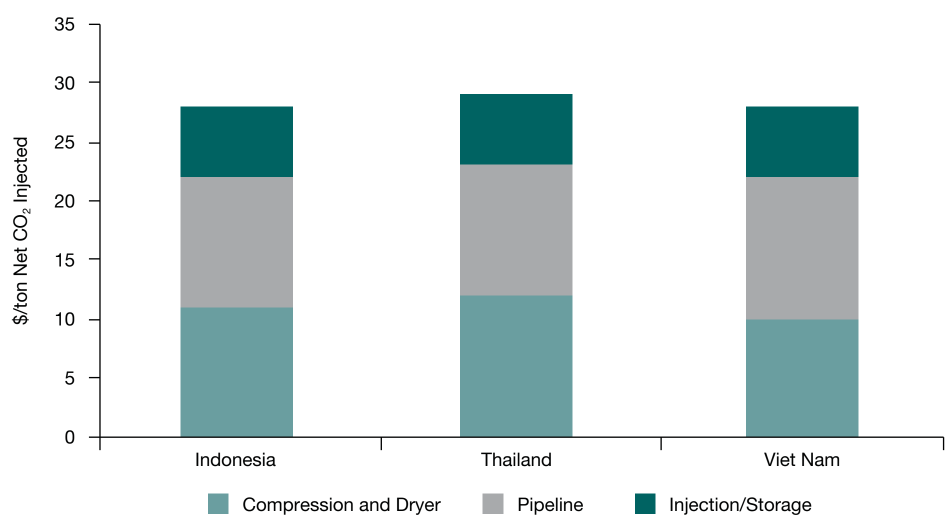
Leading source–sink matches for potential pilots that might best facilitate a transition into commercial-scale projects are the following:

- **South Sumatra (Indonesia):** The recommended option for the CCS pilot is to match an existing natural gas–processing facility with the onshore oil fields in the South Sumatra Basin.
- **Philippines:** The best pilot option would be matching the power plants in CALABARZON with the gas fields located approximately 50 kilometers northwest of the island of Palawan. Unlike in the other countries, it is unlikely that a pilot in the Philippines could start before 2024 at the earliest because the proposed gas fields will not be available for CO_2 storage prior to that time.
- **Thailand:** There are two options for the pilot: (i) match a gas-processing facility located near shore with oil and gas fields in the Gulf of Thailand, or (ii) match a coal-fired power plant with onshore oil and gas fields.
- **Viet Nam:** The proposed pilot is to match a natural gas combined-cycle (NGCC) power plant with the offshore fields in the Cuu Long Basin in South Viet Nam, unless a new gas-processing facility that removes CO_2 from the high-CO_2-content gas fields is developed.

Economic analysis confirms that natural gas processing is the lowest-cost option for carbon capture and storage, followed by natural gas combined-cycle and supercritical pulverized coal power plants.

Relative to power plants, natural gas processing with the current practice of venting pure CO_2 streams to the atmosphere offers reductions at a lower cost, with an abatement cost of approximately $30/ton (t) of net CO_2 injected, as illustrated in Figure 3. This

Figure 3 **CO_2 Abatement Costs from Natural Gas Processing** (with the current practice of venting pure CO_2 streams to the atmosphere)



Note: Natural gas processing was not evaluated for the Philippines due to the limited opportunity for this option.

cost varies slightly across the three countries. The larger share of the costs is from pipeline and injection (transport and storage).

Abatement costs for avoided emissions ($/t$CO_2$ avoided) denotes the cost of removing one t of CO_2 not including any increase in emissions from incremental efficiency losses (or energy use) in CCS. Similarly, the avoided emissions rates (kg/MWh) denotes the amount of CO_2 per MWh of generation not including the emissions from incremental CCS efficiency losses. The abatement cost for emissions captured through CCS ($/t$CO_2$ captured) denotes the cost of removing one t of CO_2 including the higher emissions from incremental efficiency losses of CCS. Similarly, the capture emissions rate (kg/MWh) denotes the amount of CO_2 per MWh of generation including the higher emissions from incremental efficiency losses of CCS.

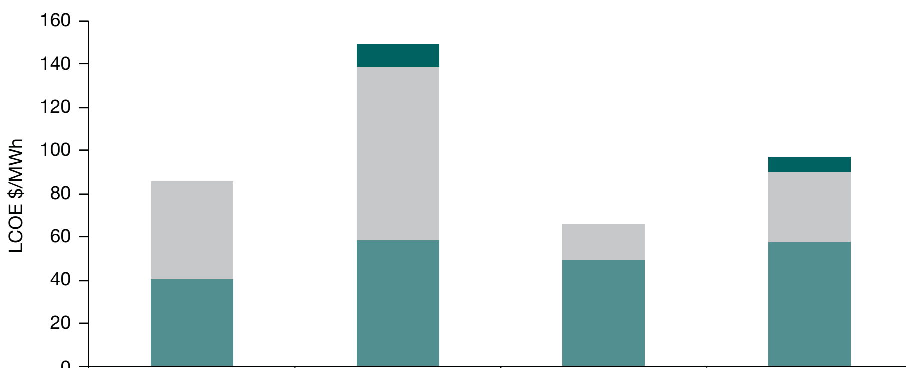
Incremental costs associated with CCS for power plants are quantified through changes in LCOE. The LCOE of a SCPC power plant with CCS increases 74% (from $86/MWh to $150/MWh) against an equivalent plant without CCS. Similarly, relative to a NGCC power plant without CCS, the LCOE of a NGCC power plant with CCS increases approximately 50% (from $66/MWh to $97/MWh), as illustrated in Figure 4.

Incremental capital costs drive the largest increase in LCOE for CCS plants. A SCPC power plant with CCS faces a nearly 100% increase in capital costs relative to a reference plant without CCS, and CCS more than doubles the capital cost for a NGCC power plant. Transport and storage constitute a relatively small part of the incremental costs, accounting for approximately 17% of the increase in LCOE of SCPC with CCS, and 23% of the increase in LCOE of NGCC with CCS.

In terms of abatement costs, CCS on a SCPC power plant costs $93/t$CO_2$ avoided and $97/t$CO_2$ avoided for NGCC, as illustrated in Figure 5.

The study also analyzed delta LCOE, which denotes the difference in the cost of electricity between a power plant with CCS and a power plant

Figure 4 **Levelized Cost of Electricity of Power Plants with and without Carbon Capture and Storage**

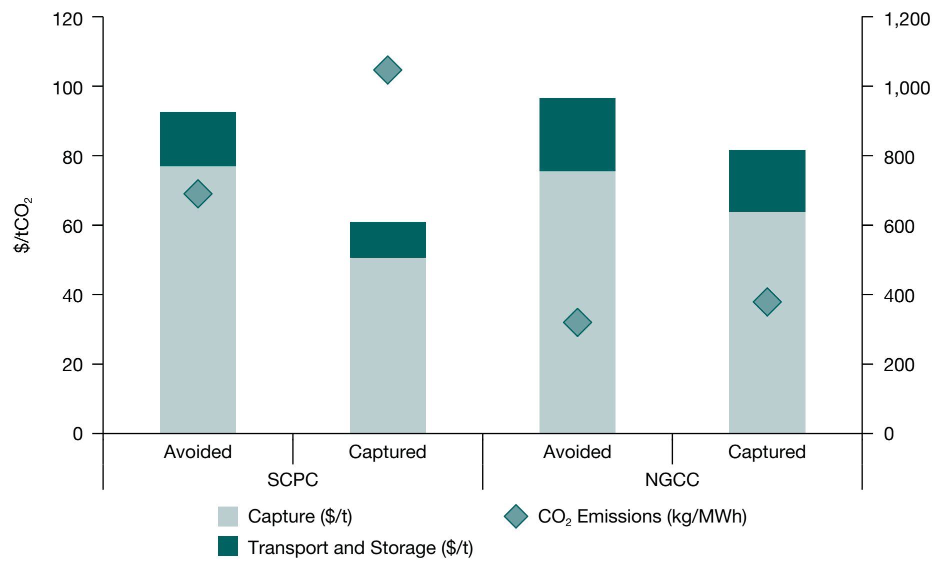


	w/o CCS	w/ CCS	w/o CCS	w/ CCS
	Supercritical Pulverized Coal		Natural Gas Combined-Cycle	
Transport and Storage	–	11	–	7
Capital and O&M	45	81	16	32
Fuel	41	58	50	58

CCS = carbon capture and storage, LCOE = levelized cost of electricity, MWh = megawatt-hour, O&M = operation and maintenance, w/ = with, w/o = without.

Note: Across the four countries, the incremental LCOE relative to a plant without CCS varies between $57/MWh and $66/MWh for coal, and between $30/MWh and $32/MWh for gas. The estimates presented here are based on the Philippines, where costs are approximately at a midpoint of the four countries.

Figure 5 **CO_2 Abatement Costs of Power Plants with Carbon Capture and Storage**



kg = kilogram, MWh = megawatt-hour, NGCC = natural gas combined-cycle, SCPC = supercritical pulverized coal, t = ton.

Note: Abatement costs vary slightly in the other three countries because assumptions specific to each country vary slightly. Country-specific results are discussed in the report generally, as well as in the respective country report executive summaries in the appendix. Estimates presented here are based on the Philippines, where costs are approximately at a midpoint of the four countries.

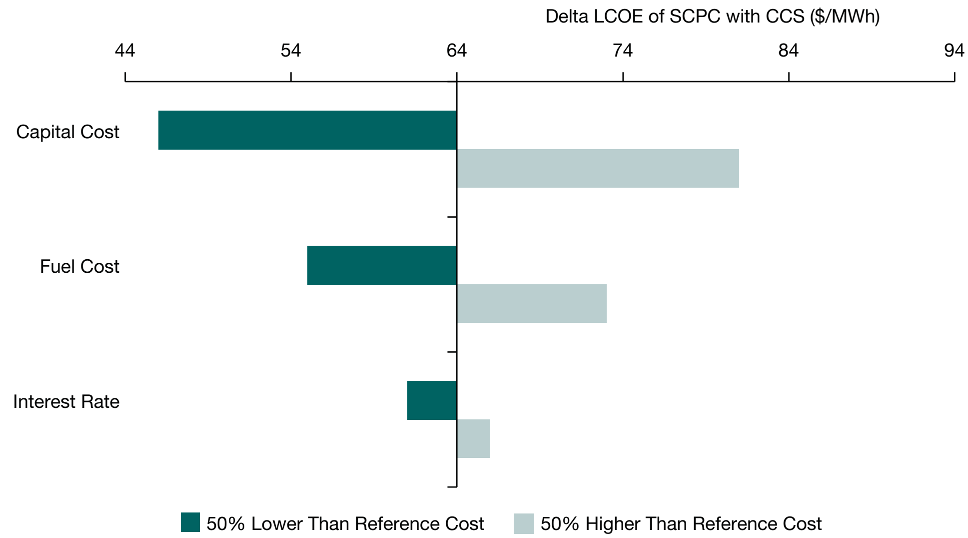
without CCS. Although the incremental LCOE in power plants with CCS is sensitive to underlying assumptions, the study finds that with reference assumptions, the delta LCOE is approximately $64/megawatt-hour (MWh) for SCPC (i.e., 74%) and $31/MWh for NGCC (i.e., 50%). Figures 6 and 7 illustrate the delta LCOE, along with the results of the sensitivities considered.

Variations in the incremental capital cost have the largest impact on the resulting delta LCOE. The results suggest that lowering the incremental capital cost of CCS via future technological gains, or from other improvements resulting from the future global development and deployment of CCS, will have large impacts on the overall affordability of CCS. Programs specifically targeting incremental capital costs are likely to be most effective in making CCS more affordable.

Variations in fuel prices and interest rates have a more moderate impact on the delta LCOE. Technological changes that enhance the energy efficiency of CCS will help reduce the delta LCOE. Changes in interest cost have very limited impact on the delta LCOE, suggesting that financing programs seeking to provide grants that cover interest costs of CCS, or provide concessional lending rates, will themselves have a rather limited impact at making CCS more affordable.

CCS-based power plants will push up power prices. Across the four countries, the LCOE for CCS coal plants is higher than prevailing wholesale prices by $58/MWh–$103/MWh. Similarly, the LCOE for NGCC power plants is higher than prevailing wholesale prices by $2/MWh–$45/MWh. In the case of the Philippines and Thailand, the LCOE of a NGCC power plant with CCS is only marginally higher than the wholesale power price. In Viet Nam, the current wholesale power price is not high enough to even cover the LCOE of new power plants without CCS. Consequently, in Viet Nam, the LCOE of CCS power plants, relative to the existing wholesale power price, must also reflect the support needed to build any new power plant.

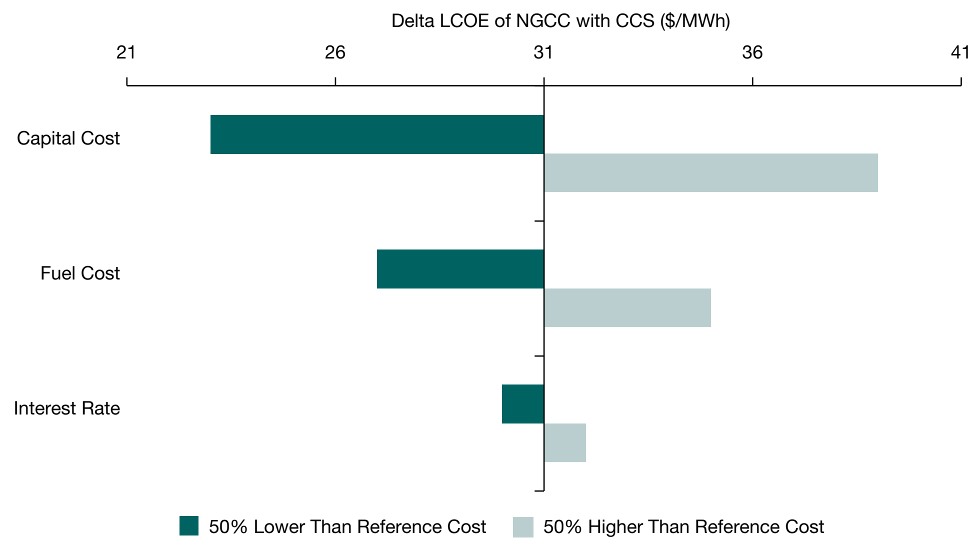
Figure 6 Sensitivity Analysis of Delta Levelized Cost of Electricity for Supercritical Pulverized Coal Power Plants with Carbon Capture and Storage



CCS = carbon capture and storage, LCOE = levelized cost of electricity, MWh = megawatt-hour, SCPC = supercritical pulverized coal.

Note: Delta LCOE is defined as the difference in the LCOE of the power plant with CCS and the same power plant without CCS. Estimates presented here are based on the Philippines, where costs are approximately at a midpoint of the four countries.

Figure 7 Sensitivity Analysis of Delta Levelized Cost of Electricity for Natural Gas Combined-Cycle Power Plant with Carbon Capture and Storage



CCS = carbon capture and storage, LCOE = levelized cost of electricity, MWh = megawatt-hour, NGCC = natural gas combined-cycle.

Note: Delta LCOE is defined as the difference in the LCOE of the power plant with CCS and the same power plant without CCS. Estimates presented here are based on the Philippines, where costs are approximately at a midpoint of the four countries.

Revenues from additional oil production resulting from CO_2-enhanced oil recovery could help offset the higher cost of carbon capture and storage.

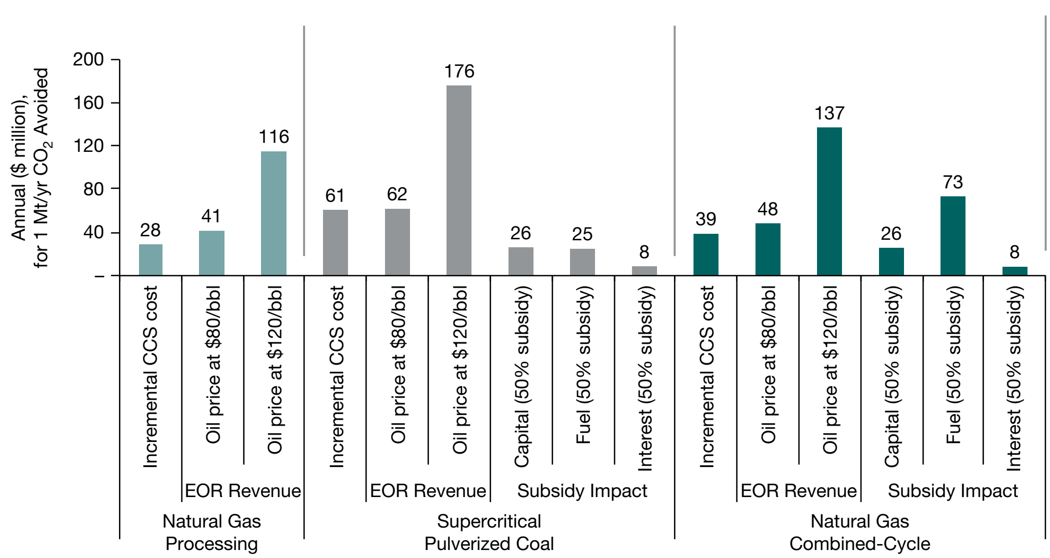
The study recommends that early commercial opportunities in CCS target CO_2-EOR. The revenues from CO_2-EOR could significantly offset additional costs from CCS, in some cases more than covering the costs of CCS. Consequently, for South Sumatra (Indonesia), Thailand, and Viet Nam where EOR opportunities were identified, the study recommends developing storage sites that are likely to offer EOR benefits.

Figures 8–11 contrast the costs against EOR revenues and subsidy impacts for an illustrative 1 Mt of CO_2 avoided (net CO_2 injected for natural gas processing) per year for all four countries. In these illustrations, depictions of EOR revenues have been estimated based on 0.32 tCO_2 per barrel (bbl) of incremental oil production. Also, 1 Mt/yr CO_2 avoided has been used as an illustrative reference, although the avoided CO_2 volume of the reference coal plant with CCS (546 MW net) is 2.8 Mt/yr, and the CO_2 emissions for the reference NGCC with CCS (482 MW net) is 1.1 Mt/yr. The CO_2 avoided costs for the power plants were calculated relative to the prevailing market tariffs for electricity available in individual countries and not delta LCOE as discussed previously—this so as to better assess prevailing market incentives. For natural gas processing, the cost of 1 Mt/yr CO_2 avoided refers to the cost of 1 Mt/yr net CO_2 injected.

The analysis reveals that CCS in natural gas–processing facilities (with notable exceptions for NGCC power plants in the Philippines and Thailand) generally offers the best gateway for broader deployment of CCS. The next best options are CCS in NGCC and SCPC power plants. Given favorable wholesale electricity market prices in the Philippines and Thailand, NGCC power plants appear to be competitive options for CCS in these countries.

It should be noted that these cost evaluations have been conducted in the context of considerable uncertainty in the international climate regime. These costs and proposed measures to finance these costs could be significantly influenced by international climate agreements and even domestic regulations within the four countries. In addition, the recommendations on the timing and selection

Figure 8 **Annual Costs, Enhanced Oil Recovery Revenues, and Subsidy Impact of a 1 Mt/yr CO_2 Capture and Storage System in Indonesia** ($ million)

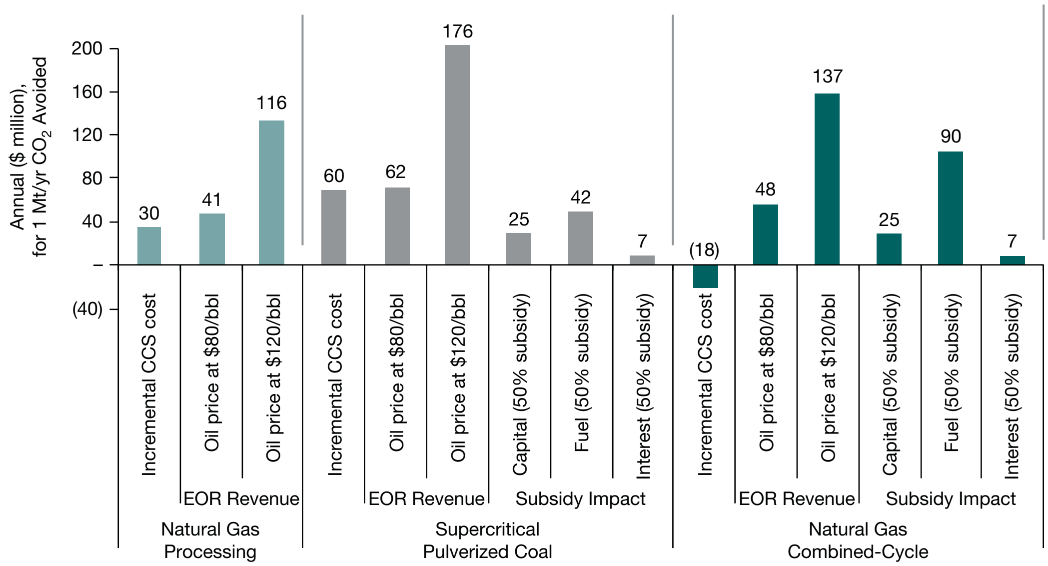


bbl = barrel, CCS = carbon capture and storage, EOR = enhanced oil recovery, Mt = megaton.

Note: For natural gas processing, the cost of 1 Mt/yr CO_2 avoided refers to the cost of 1 Mt/yr net CO_2 injected. Incremental CCS costs are relative to the wholesale power tariff in the case of power plants.

Source: ADB.

Figure 9 **Annual Costs, Enhanced Oil Recovery Revenues, and Subsidy Impact of a 1 Mt/yr CO_2 Capture and Storage System in the Philippines** ($ million)

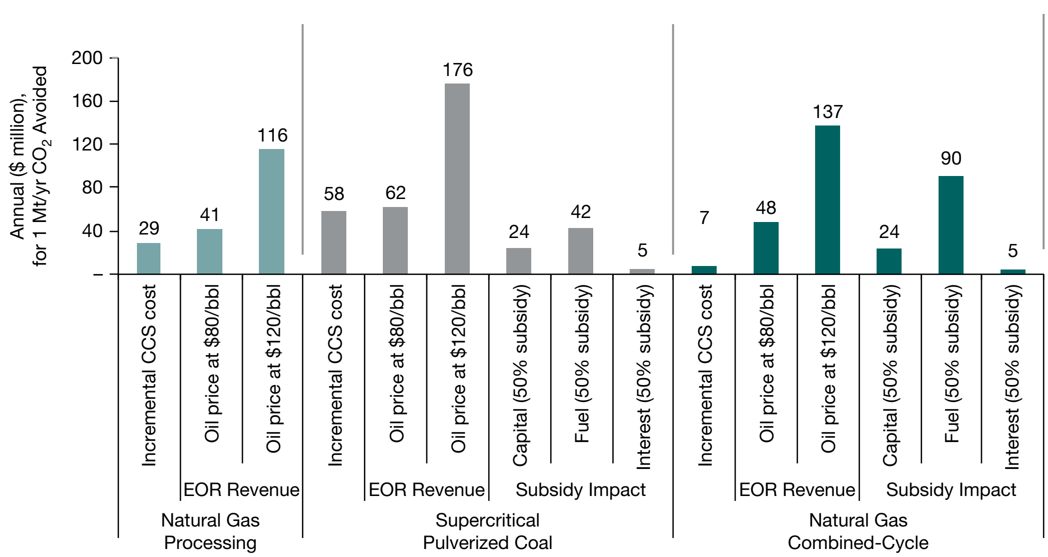


( ) = negative, bbl = barrel, CCS = carbon capture and storage, EOR = enhanced oil recovery, Mt = megaton.

Note: The option of natural gas processing was not specifically evaluated for the Philippines. However, it is presented in the economics as an illustrative option in case one emerges in the future. For natural gas processing, the cost for 1 Mt/yr CO_2 avoided refers to the cost of 1 Mt/yr net CO_2 injected. Incremental CCS costs are relative to the wholesale power tariff in the case of power plants. The negative $18 million for incremental CCS cost for NGCC signifies that CCS turns a profit rather than incurs a cost.

Source: ADB.

Figure 10 **Annual Costs, Enhanced Oil Recovery Revenues, and Subsidy Impact of a 1 Mt/yr CO_2 Capture and Storage System in Thailand** ($ million)

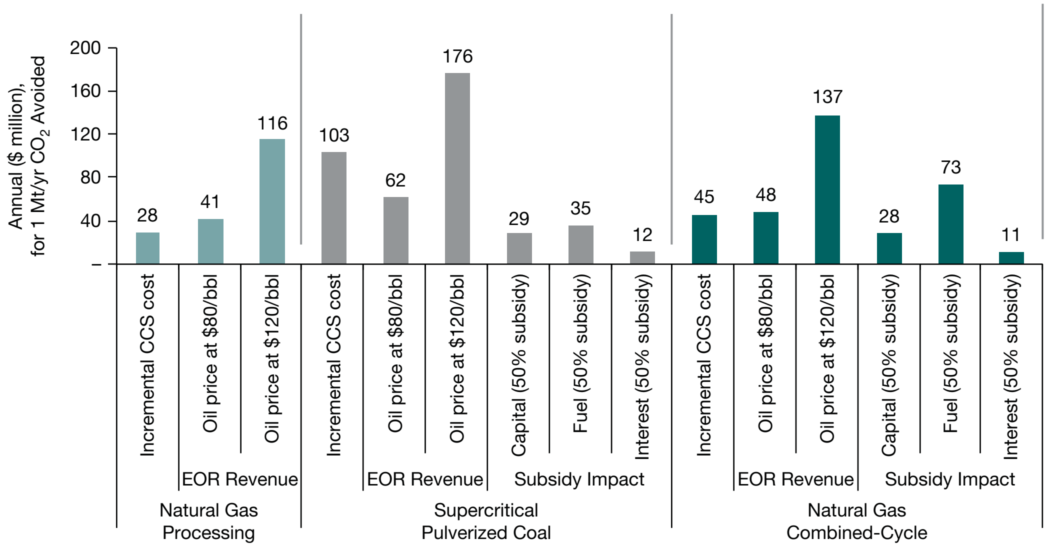


bbl = barrel, CCS = carbon capture and storage, EOR = enhanced oil recovery, Mt = megaton.

Note: For natural gas processing, the cost of 1 Mt/yr CO_2 avoided refers to the cost of 1 Mt/yr net CO_2 injected. Incremental CCS costs are relative to the wholesale power tariff in the case of power plants.

Source: ADB.

Figure 11 **Annual Costs, Enhanced Oil Recovery Revenues, and Subsidy Impact of a 1 Mt/yr CO_2 Capture and Storage System in Viet Nam** ($ million)



bbl = barrel of oil, CCS = carbon capture and storage, EOR = enhanced oil recovery, Mt = megaton.

Note: For natural gas processing, the cost of 1 Mt/yr CO_2 avoided refers to the cost of 1 Mt/yr net CO_2 injected. Incremental CCS costs are relative to the wholesale power tariff in the case of power plants.

Source: ADB.

of the deployment options could be influenced by uncertainties about the rate of technological development and the cost-benefits of different mitigation options.

Opportunities for EOR represent a good entry point for CCS, specifically in the context of these uncertainties. CCS can provide an effective mechanism for recovering parts of the costs associated with CCS. Where available, EOR may also be a suitable option for initial deployment within the four countries.

Commercial-scale carbon capture and storage requires an enabling regulatory environment, which could be framed by adapting existing regulations.

None of the four countries have any specific regulations or legal framework governing CCS. Most countries have yet to put in a legal definition for classifying CO_2. However, all of the countries have existing regulatory frameworks covering surface and subsurface rights and environmental concerns, including land, air, water, and impact assessments. These regulations can be adapted to apply to CCS. In addition, several other key regulations will need to be developed covering health and safety, liability, investment, ownership, and CO_2 transport, most of which can also be adapted from existing regulations. Emerging examples of fully developed regulatory regimes, such as in Alberta, Canada, could also be illustrative.

Developing a comprehensive regulatory framework for CCS will involve several ministries, agencies, and nongovernment stakeholders. The study recommends that such a framework be developed at the same time as implementing pilot and demonstration projects so that the framework can be in place by the time commercial-scale CCS projects are ready to be deployed. As the broader framework is being prepared, the pilot and demonstration projects can proceed with select changes to a few relevant regulations, which are just enough for these projects to commence operations. Regulations necessary to support the commercial development of CCS are outlined in Table 2.

Table 2 Legal and Regulatory Framework for Carbon Capture and Storage

Issue		Indonesia	Philippines	Thailand	Viet Nam
Classification of CO_2	Current status	No legal definition of CO_2 as a pollutant currently exists, although it is referenced in some areas.			
		Oil and gas operators required to maintain CO_2 emissions inventory	Recognized as GHG but not as an "air pollutant"	Defined only as "by-product of petroleum"	No definition
	Required for CCS	Environmental protection laws and water regulations that include definition of "waste" and "pollution," which could be used to classify CO_2.			
Surface and subsurface rights for CO_2 transport and storage	Current status	No laws for ownership, grant, or lease of surface or subsurface pore space for CCS currently exist. Only the government has power to grant mineral rights (including oil and gas), which are typically provided through production-sharing contracts.			
		Several types of land ownership rights are defined (freehold and right of use); typical duration of current rights for production sharing may be too short for CCS	Only Filipino citizens are allowed private ownership of land, though it can be leased to foreigners; subsurface rights are defined and can be obtained by private persons through lease, permit, license, or contract for a maximum of 25 years	Civil and land code offer conflicting definition of subsurface rights arising from land ownership; however, mature legal structure on existing mineral rights, with clear interpretation that state owns subsurface rights	Land use approval for industrial use currently provided for 50 years, extendable to 70 years
	Required for CCS	CCS will require long-term access through ownership, grant, lease, or contract to surface and subsurface rights, including access to pore space for storage.			
Legal liability of CCS operations and for stored CO_2	Current status	No current framework for legal liability exists for CCS.			
		Liability defined through environmental regulations affecting upstream oil and gas production	Existing environmental liability funds (EGF, EMF, MRF) could be extended to CCS; tort law, which provides liability for damages, and Clean Water Act, which also provides for damages, can also be adapted	Government-managed NEF to environmental costs arising from CCS; Petroleum Act contains financial security requirement for decommissioning; defray costs	Law on Land holds land owners responsible for protection of land; recovery for environmental costs covered under oil-gas production-sharing contracts
	Required for CCS	Short-term and long-term liability can arise. Short-term liability relates to operations (environment, health, safety). Long-term liability could relate to environmental and health risks from leakage, contamination, or migration. Liability for CCS can be addressed by adapting existing liability rules for minerals.			
Environmental protection	Current status	No environmental protection rules are currently in place for CO_2 capture process, transport, injection, or storage.			
	Laws that may be relevant to CCS	Environmental Protection and Management (2009), Water Resources, Environmental Impact Assessment	Environmental Protection, Water Resources, (Clean Water Act, Code on Sanitation, Fisheries Code, Marine Pollution) Environmental Impact Assessment requirements	Environment Protection and Promotion Act, Groundwater Protection Act, Industrial Waste Regulations, Environmental Impact Assessment	Environmental Protection (2005), Water Resources, Environmental Impact Assessment

continued on next page

Table 2 *continued*

Issue		Indonesia	Philippines	Thailand	Viet Nam
CO_2 transport	Current status	No existing regulator for CO_2 pipeline.			
		Upstream pipelines under jurisdiction of BPMIGAS under Law 22/2001 and MEMR Regulation No. 300 and Oil Gas Standard	Will require clearance under PICCS for transport; rules governing natural gas transmission, distribution and supply under Department of Energy may apply	Upstream pipelines covered by Petroleum Act under Department of Mineral Fuels (Ministry of Energy); downstream distribution pipelines regulated by ERC	MoIT governs siting of natural gas pipelines; MoNRE governs environmental standards related to pipeline
	Required for CCS	Clear regulatory and legal framework defining who can build, own, and operate pipelines (or other means) used to transport CO_2 for CCS.			
Health and safety	Current status	Standards for general occupational health and safety, as well as health and safety specific to oil and gas, are available. No standards specific to CCS currently exist.			
		MEMR Regulation No. 300 covers work health in oil and gas distribution pipeline and could apply to CO_2 transport	Occupational safety and health standards through DoLE	Occupational health and safety governed by Department of Mineral Fuels (Ministry of Energy)	Applicable occupational health and safety through MoL; safety issues in oil and gas covered by MoIT
	Required for CCS	A clear definition of health and safety for workers and of operations in CCS will be required, some of which will be adapted from existing rules.			
Enhanced oil recovery (EOR)	Current status	Limited regulations for CO_2-EOR are available in some countries.			
		Oil and gas exploration and production regulated under Law 22/2001 and GR 35/2004; awarded competitively through production-sharing contracts of 30–50 years	No EOR laws applicable to CCS; CO_2-EOR must be prespecified in work program or development plan for costs to be recovered; if CO_2 is only for storage, new law would be required	Ministry of Energy has jurisdiction over petroleum-related CO_2 streams since CO_2 is defined as a by-product under the Petroleum Act; Petroleum Act governs all aspects of oil and gas, and could be extended to cover CCS	No clear regulatory framework on EOR though permits to conduct test injections have been requested; several regulations governing EOR and enhanced gas recovery have been promulgated
	Required for CCS	A clear approach to how CO_2-EOR will be integrated into the production-sharing arrangement and built into oil-gas field development programs will be required.			
Foreign direct investment for CCS	Current status	Some controls on foreign investment in mineral exploration and production.			
		Foreign direct investment is governed by Law 25 (investment) and provides foreign-owned companies a 30-year period to operate, which can be extended by another 60 years	Generally open investment policy with some restrictions on sensitive areas; land ownership is restricted to Filipino citizens	Electricity, oil and gas, and mining are subject to foreign ownership restrictions	Projects with capital requirement greater than $1.75 billion require approval from National Assembly; investment in coal, oil, and gas must be approved by prime minister
	Required for CCS	A clear investment climate that supports foreign direct investment will be necessary for raising international funding for commercial-scale CCS projects.			

BPMIGAS = Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi (Indonesian Oil and Gas Upstream Regulatory Body), CCS = carbon capture and storage, DoLE = Department of Labor and Employment (Philippines), EGF = Environmental Guarantee Fund, EMF = Environmental Monitoring Fund, ERC = Energy Regulatory Commission, GHG = greenhouse gas, MEMR = Ministry of Energy and Mineral Resources, MoIT = Ministry of Industry and Trade (Viet Nam), MoL = Ministry of Labor (Viet Nam), MoNRE = Ministry of Natural Resources and Environment (Viet Nam), MRF = Mine Rehabilitation Fund, NEF = National Environment Fund, PICCS = Philippine Inventory of Chemicals and Chemical Substances.

Source: ADB analysis.

The study recommends using an effective public communication and engagement process to support carbon capture and storage development.

There is currently little public awareness about CCS. The study recommends the development of a communication and public engagement process, to occur alongside pilot and demonstration projects and prior to starting commercial-scale CCS. The study also recommends undertaking comprehensive impact assessments of potential CCS pilots and inviting participation from various stakeholders, particularly from the local communities involved.

In summary, the study concludes the following:

- Capture should first be installed in natural gas–processing facilities. Such opportunities are available in Indonesia, Thailand, and Viet Nam.
- Oil fields that offer CO_2-EOR opportunities should be used as the initial storage sites to defray the cost of CCS. Such EOR opportunities are available in Indonesia, Thailand, and Viet Nam. The initial pilot would have a large measurement, monitoring, and verification (MMV) component.
- Transporting CO_2 to the pilot at the storage site would be by truck or boat as only relatively small amounts of CO_2 will be injected. Pipelines would be used for the later, larger demonstration projects.

Table 3 summarizes the key findings of the state of CCS opportunities in the four focus countries.

The study offers a comprehensive 15-year road map, starting with a pilot that provides the basis for subsequent demonstration and commercial carbon capture and storage projects.

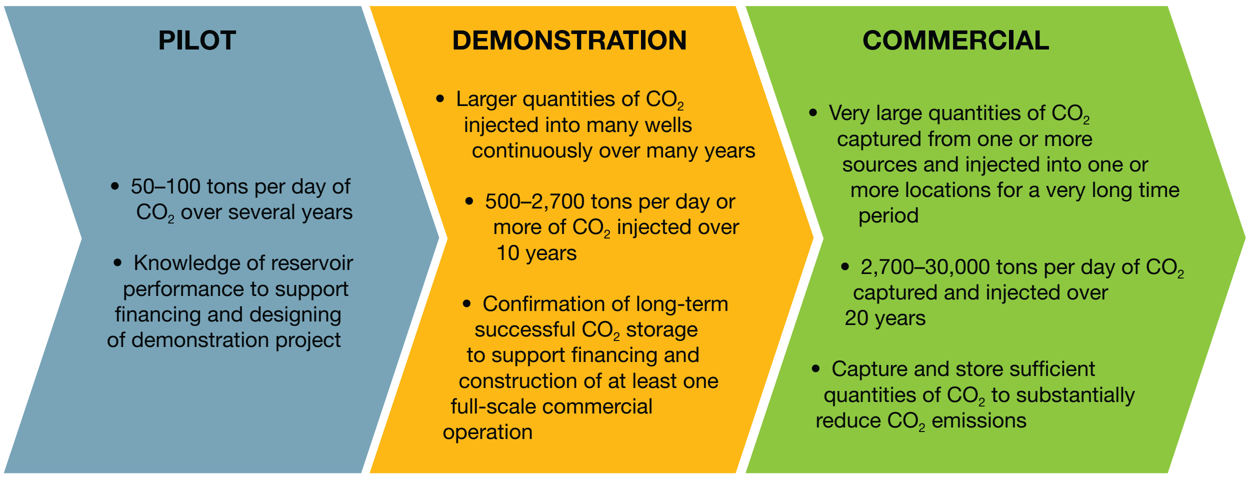
The proposed road map, applicable to all four countries studied, stretches over 15 years. It includes a timeline for all activities relating to project development, with most of the detail directed at the pilot phase. The road map is aimed at piloting a CCS project that will lead to developing a demonstration and commercial project (Figure 12).

The storage pilot project, achieving approximately 50–100 tCO_2 injected per day, is estimated to require a capital outlay of around \$50 million–\$60 million over a 5-year period, and then transition to a demonstration-scale project in the sixth year. Building on the pilot, the demonstration project capturing and injecting 2,700 tCO_2 per day (1 Mt/yr) is expected to require an additional \$900 million and be operational

Table 3 Carbon Capture and Storage Opportunities in the Focus Countries

Item	Natural Gas Processing	Supercritical Pulverized Coal	Natural Gas Combined-Cycle
Capture Opportunities			
Indonesia	Potential existing source identified	Potential existing source identified	
Philippines		Potential existing source identified	Potential existing source identified
Thailand	Potential existing source identified	Potential existing source identified	Potential existing source identified
Viet Nam	Potential future sources from new high CO_2 gas fields	Potential future source identified	Potential future source identified
Storage Sites with Enhanced Oil Recovery Potential			
Indonesia	Potential existing site identified		
Philippines	Non immediately available/potential nonconventional storage sites recommended for more detailed analysis		
Thailand	Potential existing site identified		
Viet Nam	Potential existing site identified		

Figure 12 **Stages of Carbon Capture and Storage Development**



for 6 years, i.e., between 10–15 years. The detailed road map outlining specific activities across all of the project components is presented in Chapter 8 of the full report.

The further development of CCS requires engagement across a wide range of stakeholders. The study recommends the continuation of the CCS working groups which were formed in each of the four countries at the outset of this regional technical assistance project. The study also suggests that the working groups be institutionally integrated within government, and empowered with budgets and a decision-making ability framework, so that they can coordinate with government, policy makers, industry, and the public in managing the CCS development process.

In addition, developing CCS must include the presence and active involvement of local personnel throughout the project development cycles. This will enable capacity building and minimize the need for international technical assistance by the time the demonstration project is deployed.

A key aspect of the CCS development process will be the learning and knowledge that must be transferred from CCS project developments in other parts of the world, and subsequently a significant focus on local capacity building. Companies engaged in CCS, for example oil-gas companies, must be able to learn from ongoing project developments in other parts of the world. Capacity building among local stakeholders must occur across all aspects of project development: technical, financial, environmental, community engagement, regulatory, legal, and institutional. The road map proposed in this report provides the opportunity for capacity building across all of these areas.

1 Introduction

The International Energy Agency (IEA) projects in its latest forecast, the *World Energy Outlook 2011* (IEA 2011a), that global primary energy demand will increase by a third between 2010 and 2035. This projection is the IEA's central forecast, the New Policies Scenario, and reflects all of the policies enacted by mid-2011, as well as recently announced plans even if those policies have not been formally adopted or implemented. About 95% of that growth by 2035 will come from non-Organisation for Economic Co-operation and Development (OECD) economies, with 50% coming from the People's Republic of China and India alone. Approximately 11% of that growth is projected to come from other developing Asian countries.

Though the share of fossil fuels in primary energy consumption is projected to fall from around 81% in 2012 to 75% in 2035, the use of coal, which met almost half of the increase in global energy demand over the last decade, is estimated to rise 65% by 2035 (IEA 2011a). The global demand for natural gas is projected to grow much more rapidly than either coal and oil, reach nearly 5.1 trillion cubic meters (TCM) by 2035, more than 50% higher than current levels (IEA 2011b).

If left unabated, this large increase in the availability and consumption of coal and natural gas has the potential to drive up carbon dioxide (CO_2) concentrations to 650 parts per million (ppm), which could result in a global temperature increase of about 3.5°C. To achieve a greenhouse gas (GHG) concentration of 450 ppm, and thus keep global temperature increases below 2°C, the world must achieve GHG reductions of 15 gigatons (Gt) annually by 2035 relative to projections contained in the IEA's New Policies Scenario. The IEA projects that 65% of this reduction will need to happen in non-OECD countries.

Carbon capture and storage (CCS) has a key role to play in achieving these reductions. The IEA projects that by 2035, CCS, among a portfolio of abatement options, could help provide 22% of the emission reductions required to achieve GHG concentrations of 450 ppm. To achieve this magnitude of emission reductions, CCS will need to be widely adopted: 32% of coal power plants, 10% of gas power plants, and 40% of industrial sources will need to be equipped with CCS. However, the current pace of new project development, as will be noted, suggests that this goal may be hard to reach.

Eight CCS projects are currently in operation around the world. Including those in the identification stage, 74 projects are at different stages of consideration (Global CCS Institute 2011b). Given the pace of current developments and the projected importance of CCS in delivering emission reductions, a renewed interest in the technology is becoming all the more essential (IEA 2009).

The projected growth in natural gas production also affords greater opportunities for CCS deployment. The IEA projects that, spurred by the discovery of large nonconventional gas sources, natural gas consumption will grow from 2,539 million metric tons of oil equivalent (Mtoe) in 2009 to 3,928 Mtoe in 2035, accounting for 23% of the global energy mix by 2035 (IEA 2011a).

Natural gas processing offers one of the lowest cost options for CCS since it can often be coupled with easy access to CO_2-enhanced oil recovery (EOR) and thus provide an additional source of revenue. Six of the eight currently operating CCS facilities, and two of the seven CCS projects under implementation, are associated with natural gas processing. Although natural gas currently accounts for just over a quarter of the primary commercial energy supply in

Indonesia, the Philippines, Thailand, and Viet Nam collectively (BP 2010), the share of gas in the energy mix is likely to increase as these countries tap into local reserves and rely on liquefied natural gas (LNG) imports.

CCS technology is not without risks and challenges. Large-scale, cost-effective, integrated CCS technologies that bring together capture, transport, and storage have yet to be commercially proven for power generation applications. CCS is currently being applied mainly in large natural gas–processing facilities in Africa, Europe, and North America. Although a few integrated CCS projects on coal-fired power plants are now being implemented in Canada and the United States, wide-scale commercial confidence in such applications is yet to emerge.

In addition to technological risks, particularly in power generation applications, CCS is an expensive abatement option with high financing hurdles, even though it can be cost-competitive with some low-emission technologies when compared without subsidy support. CCS leads to relatively high energy losses in power generation and is yet to achieve widespread public acceptability. Past studies seeking to identify specific opportunities and enhance public awareness have yet to coalesce into a critical mass of broader support and increased confidence in CCS.

To emerge as a meaningful part of global GHG emissions abatement strategies, CCS must be increasingly deployed in developing countries where some of the highest growth in energy use and emissions is likely to occur. To date, much of the CCS effort has been limited to developed countries. Efforts to promote and build the basis for CCS deployment must instead start focusing on the specific context and challenges of energy and environment in developing countries.

1.1 Context

Indonesia, the Philippines, Thailand, and Viet Nam—the four focus countries of this study—collectively represent a dynamic group of economies. These countries have been among the fastest-growing economies in the world, and such growth is projected to continue. Efforts to integrate CCS within the development strategy of these countries must fit with their concerns regarding energy supply and demand, energy security, and climate change.

1.1.1 Climate Change

Southeast Asia is one of the world's most vulnerable regions to the impacts of climate change because of its unique economic and social characteristics, long coastlines, and mostly tropical climate. It has been one of the world's most dynamic and fastest-growing regions in past decades, yet it still faces the daunting task of eradicating income and non-income poverty. The poor are the most vulnerable to climate change impact. Much of the region's growth is also dependent on natural resources, particularly forestry, putting considerable pressure on the environment and ecosystems. At the same time, the region's urbanization is among the fastest in the world, particularly in coastal areas where about 80% of the population lives within 100 kilometers (km) of the coast. This is leading to an overconcentration of economic activity and livelihoods in coastal megacities (ADB 2009).

Growing populations, rising incomes, and changing consumption patterns have boosted overall demand for food and industrial crops from both within and outside the region, and led to rising food prices on a global scale. In response, the region has intensified the production of grains, animal feed, and industrial crops. The increased use of fossil fuels to support these response strategies further compounds climate impact concerns because of its large local impact on land use, water, and air quality.

Each of the four focus countries is acutely aware of these challenges, and particularly of the urgent need to balance economic growth, industrial growth, and environmental stewardship. They have each formulated an action plan on climate change which integrates mitigation, adaptation, technology, financing, and other local needs. These plans are at different stages of implementation and maturity, but they all incorporate a common theme: a vision to eventually migrate to a low-carbon economy that continues to support their development imperatives.

1.1.2 Energy Security

Rapid economic growth, development, increased industrialization and improved energy access have led to strong growth in the energy demand of these four countries. Excluding the Philippines, the three other countries posted 4%–5% annual growth in energy use over the last decade. Demand for energy is likely to continue to grow at these levels.[1]

Much of the increase in energy use over the last decade has been met through the use of fossil fuels. Coal, natural gas, and oil are available in Indonesia and Viet Nam, and to a lesser degree in Thailand and the Philippines, though not enough to meet all of their domestic energy needs. Despite efforts to promote the use of renewable energy and increase energy efficiency, fossil fuels are likely to dominate the energy mix of these countries over the next few decades.

Import dependence, particularly of oil, is projected to grow. Indonesia's oil imports (as a share of consumption) will increase from 30% in 2007 to 100% in 2030; the Philippines will maintain its current level of import dependency, at about 95%; and Thailand will increase its net imports from 60% in 2007 to 85% in 2030. Viet Nam is expected to transition from a net oil-exporting country to eventually importing more than 30% of its oil by 2030 (USAID 2011).

Indonesia and Viet Nam have large reserves of natural gas, some untapped, which will cover the bulk of their domestic consumption. The Philippines and Thailand have small reserves of natural gas, and Thailand is already importing natural gas from neighboring Myanmar through a pipeline. There is no extensive surface transport infrastructure in the region for natural gas, and the fragmented nature of the islands of Indonesia and the Philippines make the situation all the more difficult (IEA 2010).

CCS offers the potential to reduce immediate import dependency on oil and gas while also abating CO_2 emissions. Given declining domestic supply and depleting oil and gas wells, especially in Indonesia and Viet Nam, captured CO_2 can be used in enhanced oil recovery (EOR) or enhanced gas recovery (EGR) to help these countries extract more oil and gas from their existing fields. Natural gas must be separated from CO_2 before it can be commercially sold, and the high-CO_2-content gas in several of the new potential fields implies that CO_2 separation must occur anyway. This could offer a low-cost source for CO_2 capture: EOR and EGR can help utilize the sequestered CO_2 and, in the process, offset some of the initial CCS costs while building the basis for a transition to a long-term CO_2 storage future.

1.2 Previous Studies

This study builds on several past and ongoing studies on CCS in Southeast Asia. In 2009, a study prepared by the Indonesia CCS Working Group, under the joint cooperation of the United Kingdom and Indonesia, conducted a preliminary evaluation and found that Java and Sumatra had the best available capture options. It suggested that gas-processing facilities could offer the lowest CO_2 capture cost, and the report[2] concluded that there is large potential for oil recovery and CO_2 sequestration in East Kalimantan and South Sumatra.

Several studies have been conducted in Viet Nam.[3] Agence Française de Développement (AFD) supported a preliminary assessment of storage sites, emission sources, transport links, and regulatory environment. The study revealed promising opportunities for storing carbon emissions geologically and for commercial use in EOR and enhanced coal bed methane (ECBM) projects (BRGM 2009). Petrovietnam (PV), in collaboration with Mitsubishi Heavy Industries, conducted two feasibility studies for CO_2-EOR in the Rang Dong (Aurora) and Bach Ho (White Tiger) oil fields. The study results indicated that 8% incremental oil can be recovered using supercritical CO_2.

The IEA and the Global CCS Institute carried out a series of workshops to introduce CCS to national ministries in Viet Nam and Malaysia during early 2010. The Asia-Pacific Economic Cooperation (APEC) forum completed an initial evaluation of geological storage potential for countries in Southeast Asia and a study of CCS-ready power plants in the region. Two oil and

[1] The Philippines is set to witness an annual economic growth of nearly 3.4%, through 2030, more than doubling its energy consumption as compared to 2002 levels (APEC 2006).

[2] See Indonesia CCS Working Group (2009).

[3] In addition, Viet Nam currently has an operational CO_2 capture facility at the Phu My Fertilizer plant that is currently capturing 240 t/day.

gas companies, PTT (formerly Petroleum Authority of Thailand) and Chevron, have both indicated that they are studying CCS in the Gulf of Thailand using CO_2 produced on nearby platforms, but few details are available.

The first two applications made to the Executive Board of the Clean Development Mechanism (CDM)[4] for developing methodologies for CCS projects were from Southeast Asia: EOR at the White Tiger (Bach Ho) oil field in Viet Nam and a liquefied natural gas project combined with geological storage in Malaysia. This illustrates that there is an interest and understanding within the region of the role that CCS can play as a mitigation option against climate change.

1.3 Study Purpose and Scope

This study has been designed to overcome the existing information gaps and to provide the basis for supporting long-term action on CCS in Southeast Asia, specifically in four focus countries: Indonesia, the Philippines, Thailand, and Viet Nam. It was conducted under Regional Technical Assistance (RETA) 7575 "Determining the Potential Carbon Capture and Storage in Southeast Asia," executed by the Asian Development Bank (ADB) with funding from the Carbon Capture and Storage Fund[5] under the Clean Energy Financing Partnership Facility. The governments of these countries formally indicated their interest in participating in this regional activity.

The study impacts, outcome, outputs, implementation arrangements, and costs were finalized in discussions with key agencies in these countries. The study has the following key objectives:

(i) Create an inventory of CO_2 emission sources and develop a ranking methodology to select the most promising sources.

(ii) Create an inventory of potential storage sites and develop screening criteria for ranking CO_2 storage options, followed by source–sink matching.

(iii) Identify appropriate pilot projects for implementation.

(iv) Recommend a specific, actionable, and implementable road map that could serve as a guide toward a pilot project, demonstration, and eventual commercialization of CCS.

(v) Develop an internal network of agencies and personnel in the form of CCS working groups, with the capacity to carry such projects forward with minimal foreign assistance.

Partnering with local agencies (universities, government ministries, and research centers), the study was prepared by a team of national and international experts. It followed a systematic approach, building analytical blocks toward a feasible and comprehensive road map. The approach used by the study team is illustrated in Figure 1.1.

The CCS road map offers a platform for subsequent targeted initiatives toward a pilot and a demonstration that could

(i) establish an enabling environment,

(ii) examine the technical and financial aspects related to capture and/or storage,

(iii) identify and prepare prefeasibility reports for pilot and demonstration projects, and

(iv) lead to successful pilot tests and demonstration projects.

1.4 Geographic Scope

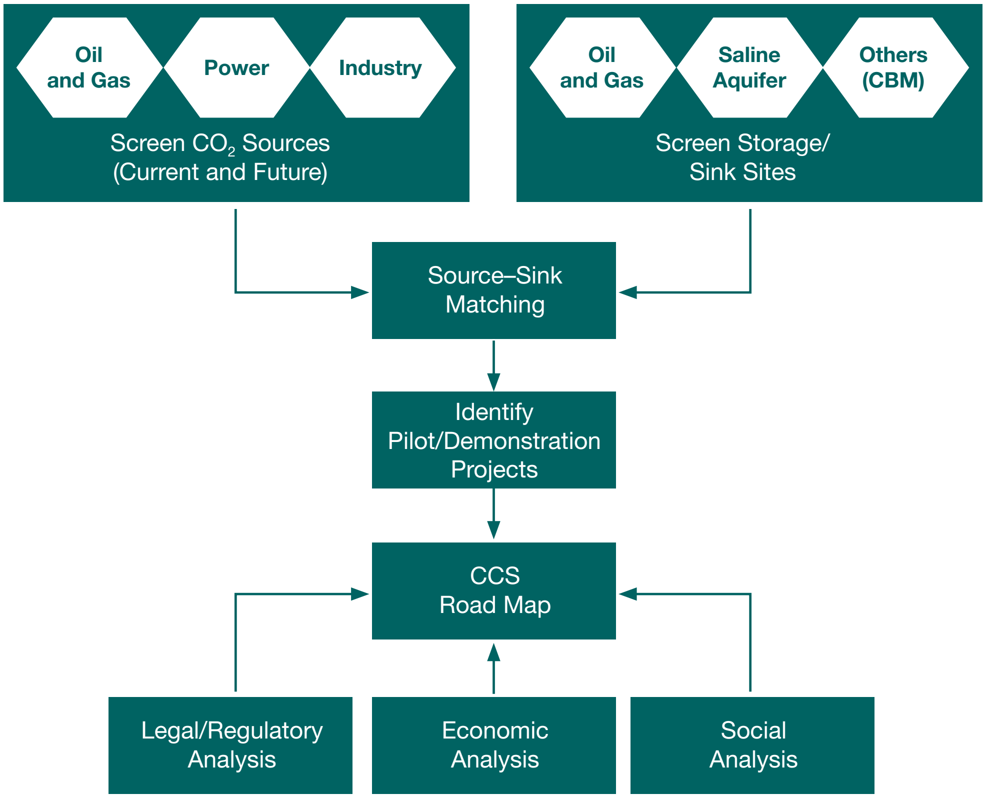
Given the large geographical spread and fragmented nature of the islands in Indonesia and the Philippines, and the clustered nature of large emission sources and sinks, the physical boundary of the study covers specific regions within these countries.

In Indonesia, the study focused on South Sumatra. The region possesses several attributes that make it well suited for CCS: abundant large CO_2 point sources, many opportunities for storage, and an existing transportation network linked to oil and gas activity. Although South Sumatra remains the focus, several insights and recommendations of the study are relevant broadly across Indonesia.

4 The Conference of the Parties (COP), serving as the meeting of the parties to the Kyoto Protocol, decided at the Durban COP in 2011 that CCS in geological formations is eligible as a project activity under the CDM.

5 Contributors: Global Carbon Capture and Storage Institute, and the Government of the United Kingdom.

Figure 1.1 **Study Approach**



CBM = coal bed methane, CCS = carbon capture and storage.

In the Philippines, the study focused on evaluating the CO_2 capture potential of major stationary CO_2 sources in the region of CAvite, LAguna, BAtangas, Rizal, and QueZON (CALABARZON). CALABARZON is an acronym for the five provinces in the immediate vicinity of the National Capital Region (NCR) or Metro Manila. CO_2 emissions from this relatively compact geographic region contribute a disproportionately large share of the total energy-based GHG emissions of the whole of the Philippines. Potential storage locations were subsequently identified in the vicinity of the capture locations, though sources and storage potential across the country have also been broadly discussed.

The land masses of Thailand and Viet Nam are contiguous, and CO_2 sources and storage across both countries were assessed. A range of sources in the north and the south of the two countries were evaluated.

1.5 Report Organization

This report contains nine chapters, in addition to an appendix and an executive summary.

Chapter 1 (this chapter) provides the broad motivation for CCS and the imperatives that could shape its deployment in the four focus countries. The chapter also describes the purpose, scope, and geographic boundary of the study.

Chapter 2 provides a background to the Southeast Asian region, specifically highlighting the economies, energy, and GHG emissions of the four countries. It concludes with a detailed background and discussion of CCS technology.

Chapter 3 discusses the CO_2 emissions inventory and identifies existing and planned sources that could be suitable for capture. It describes the screening methodology used in determining the capture suitability of each source, and discusses the sources and scores for capture suitability achieved by the leading sources.

Chapter 4 contains an analysis of CO_2 storage opportunities in oil and gas fields, saline aquifers, coals, and other options. It discusses the methodology used in assessing the suitability of the storage options, along with the score of suitability achieved by the oil and gas storage options.

Chapter 5 presents source–sink matching and the leading options for demonstration/commercial projects in each of the four countries.

Chapter 6 discusses the cost impacts of potential CCS applications. It provides a description of the cost and technical assumptions used in the study. It discusses the findings on costs across a range of sensitivities and outlines several potential financing mechanisms.

Chapter 7 identifies existing legal and regulatory frameworks that relate to CCS, and explores how these existing frameworks could be adapted to CCS. It also discusses socioeconomic and public perception issues relevant to developing CCS, reporting back from the stakeholder discussions that were part of the study.

Chapter 8 presents the road map for CCS development.

Chapter 9 highlights key conclusions and recommendations from the study.

Finally, the appendix contains executive summaries of the more detailed and confidential country reports conducted for each of the four countries.

2 Background

2.1 Economy

Southeast Asia is geologically, demographically, environmentally, and economically one of the most dynamic and vibrant subregions of Asia. The four focus countries in the study—Indonesia, the Philippines, Thailand, and Viet Nam—cover nearly 70% of the geographic area of Southeast Asia and are home to over 80% of the region's population (World Bank's World Development Indicators [WDI] 2010). Figure 2.1 provides comparative measures of the economies and demographics of the four countries.

From 1990 to 2007, the region's gross domestic product (GDP) grew 5.5% annually, compared to the world's 2.9%. In per capita terms, annual GDP grew at 3.6%, compared to a global average of 1.5%. Despite challenges from the recent global economic slowdown, the region is expected to keep its growth momentum in the near term and in the longer run. Over the next 5 years, the region is expected to grow at an annual rate of 5.6% (OECD 2011) and later make a push toward its pre-2008 rates. The region's economic resilience is underpinned by strong regional and domestic demand, given its large populations and broad resource base.

High levels of investment in physical and human capital, pragmatic trade and industrial policies, a vibrant external sector, and structural reforms—especially after the 1997/1998 Asian financial crisis—have underpinned the region's growth and performance. Rapid economic growth and structural transformation have helped lift millions of Southeast Asians out of extreme poverty. During 1990–2005, poverty incidence in Indonesia declined 32.8%, in the Philippines 7.0%, in Thailand 9.0%, and in Viet Nam 11.4%. However, as of 2005, about 93 million (18.8%) Southeast Asians still lived below the $1.25-a-day poverty line, and 221 million (44.6%) below the $2-a-day poverty line (ADB 2009).

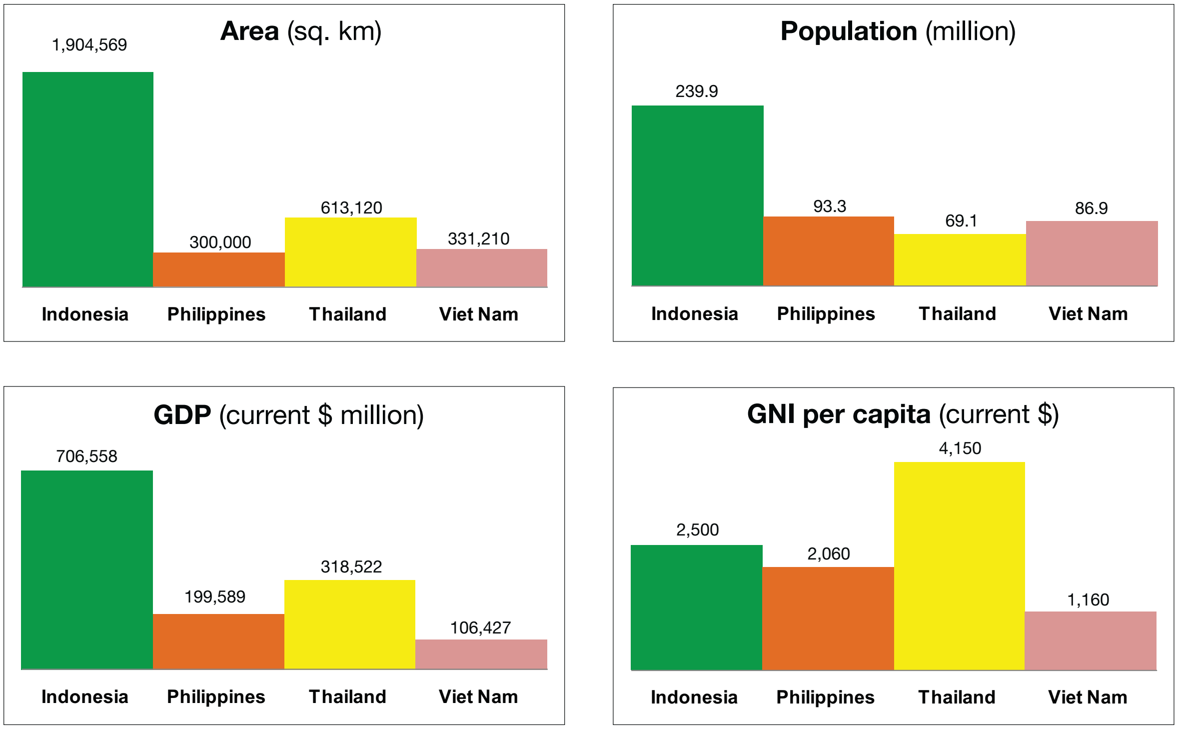
Despite rapid economic growth and structural transformation, agriculture remains a major economic sector. In 2006, agriculture contributed to a significant portion of GDP of these countries: 12.9% in Indonesia, 14.2% in the Philippines, 10.7% in Thailand, and 20.4% in Viet Nam. Structural changes in the economies are expected to drive economic growth, with agriculture's contribution to GDP continuing to decline over the next decade. In parallel, Southeast Asia is steadily urbanizing. As of 2010, 41.8% of the region's population, or 246.7 million people, lived in urban areas. This was only 15.5% in 1950. The United Nations expects that the urban population of the region will have increased to 49.7% by 2025 (ISEAS 2010).

2.2 Energy

Economic growth accompanied by a structural shift toward industrial production and services, along with the inevitable urbanization that followed, has significantly influenced energy use patterns across the four Southeast Asian countries. All four of these countries experienced strong energy growth over the last decade (2001–2010), with cumulative final energy consumption reaching approximately 300 million tons of oil equivalent (Mtoe) (Indonesia 157 Mtoe, the Philippines 35 Mtoe, Thailand 60 Mtoe, and Viet Nam 50 Mtoe).

Viet Nam witnessed more than a doubling (120%) of its energy consumption over 2001–2010. Indonesia's final energy demand grew by 3.5% on average per year during that time, while Thailand's energy use grew annually by 4.3% on average. The only exception has been the Philippines, which achieved a modest annual average energy growth rate of 0.42%. These levels of energy growth are expected to continue. Average annual energy growth is projected to range between 4% and 5% in Indonesia, Thailand, and Viet Nam and between 3% and 4% for the Philippines.

Figure 2.1 **Summary of Focus Countries**



GDP = gross domestic product, GNI = gross national income, sq. km = square kilometer.
Source: World Bank's World Development Indicators 2010.

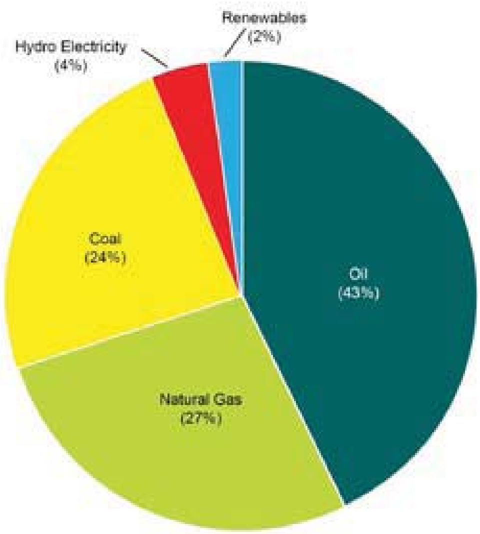
Fossil fuels currently dominate the energy mix of the four countries, accounting for more than 90% of their commercial energy supply, as illustrated in Figure 2.2.

The region's continued reliance on coal and natural gas to meet growing energy needs will persist well into the future. Across the four countries, coal is expected to provide the majority of the power sector's fuel demand. In Viet Nam, domestic coal production is set to double from current levels to 90 megatons (Mt) by 2030. From 2010 to 2030, coal demand from the power sector is projected to grow 7.6% annually, reaching 110–150 Mt. Coal-fired power generation is expected to increase fourfold in Indonesia over the same period, tapping increasingly into the significant domestic coal resources that are available. By 2030, the Philippine Energy Plan envisages a 100% growth in domestic coal production, though indigenous coals are mostly low rank (lignite and subbituminous) with few medium-rank coals (bituminous B and C), which are not the best suited for a high-efficiency supercritical power plant. Thailand's dependency on coal is also projected to increase from 10 Mtoe to about 20 Mtoe between 2010 and 2030.

Natural gas consumption follows a similar trend of sharp growth. Projections for natural gas consumption according to the IEA (IEA 2011b) indicate that non-OECD countries will account for nearly 80% of the increased gas consumption between 2010 and 2035 (IEA 2011a). Indonesia also has fairly large resources of unconventional gas, such as coal bed methane (CBM), which is likely to drive up gas-based consumption in power generation. Thailand already has the third largest fleet of vehicles in the world based on compressed natural gas as fuel.

In all of the focus countries, gas consumption growth is outstripping production growth, resulting in the need for more exploration or large import dependency. As

Figure 2.2 **Primary Commercial Energy Supply in the Four Countries of the Study, 2010**



Source: BP (2010).

of 2010, Indonesia was the third largest exporter of natural gas. Indonesia has one of the world's largest untapped reserves of natural gas in its Natuna D-alpha fields, which has estimated reserves of 6 trillion cubic meters, though with a high carbon dioxide (CO_2) content (nearly 70%). In Thailand, natural gas currently represents around 70% of the country's electricity generation, although it imported 20% of its consumption (BP 2010) through pipelines from neighboring producers. The Philippines and Viet Nam rely on domestic production as they have no pipeline infrastructure in place to import from exporting countries in the Association of Southeast Asian Nations (ASEAN) region. However, all the countries are considering the construction of liquefied natural gas (LNG) terminals or already have construction under way[6] (IEA 2011a). Oil and gas resources in the Philippines remain largely underexplored with only 10% of the oil and gas resources discovered, leaving considerable room for expansion in the future.

The four countries have initiated several programs to promote the use of renewable energy, increase energy efficiency, and promote the adoption of nonconventional energy sources, such as geothermal. Although the specific programs vary by country, some of the leading initiatives provide targets for renewable energy generation; offer feed-in tariffs, tax incentives, and other fiscal incentives; and provide risk guarantee and access to concessional financing. Although these efforts will help renewable and non-fossil energy sources to occupy a larger share of the energy mix, they are unlikely to displace overall reliance on fossil fuels over the next few decades.

2.3 Greenhouse Gas Emissions

Commensurate with increased fossil fuel consumption, CO_2 emissions have grown sharply across all four countries.

Indonesia has the highest greenhouse gas (GHG) emissions rate among the four countries. Its GHG levels grew 5.3% annually between 2000 and 2005 to reach 1,760 Mt CO_2e. Though nearly 60% of these emissions currently result from land-use change and agriculture, with energy use accounting for a fifth of total emissions, the highest increase in emissions is projected to come from energy use. GHG emissions from energy use are expected to almost triple, accounting for 35% of total emissions by 2020.

In the Philippines, overall CO_2 equivalent (CO_2e) emissions from energy grew 2.2% annually between 1994 and 2009, to reach 69 Mt CO_2e. In 1994, when the last official inventory was made available, GHG emissions from the energy sector accounted for approximately 50%. Approximately 40% of the emissions (28 Mt CO_2e) from energy use come from the power sector. The power sector is expected to witness a threefold increase in emissions by 2030, with an additional 60 Mt CO_2e.

Thailand's overall GHG emissions were 230 Mt CO_2e in 2000. The energy sector contributed to 70% of these, with power production alone accounting for 41%. Thailand's GHG emissions under the Power Development Plan 2010 scenario are estimated to be 473 Mt CO_2e in 2020, with electricity generation contributing to nearly 119 Mt CO_2e of that amount.

6 Number of LNG terminals proposed/under construction: Indonesia (for exporting)—3, Philippines—2, Thailand—1 (under construction), and Viet Nam—1.

Viet Nam's GHG emissions have increased about 2.5% annually between 2000 and 2010 to reach 170 Mt CO_2e. Nearly 35% of these emissions come from the energy sector and are set to grow at a rate of 6% annually through 2030. Within the energy sector, CO_2 emissions from the power sector are projected to grow from approximately 50 Mt CO_2e in 2011 to 450 Mt CO_2e by 2030.

Energy use is already a large part of the current GHG mix and the largest share of the current emissions growth. The continued growth of fossil fuel use will remain the key driver of future GHG emissions, emerging as the dominant part of the GHG source mix. Although emissions growth rates will vary across countries, the four countries could account for an additional 700 Mt to 1 billion metric tons CO_2e emissions from energy use by 2035.

The four countries are all acutely aware of rising GHG emissions and the challenges resulting from continued reliance on fossil fuel use. They have begun to make concerted efforts to reduce GHG emissions through domestic action and international climate negotiations. In 2009, Indonesian President Susilo Bambang Yudhoyono announced that the country would adopt an energy mix policy that would achieve a 26% reduction in emissions by 2020 from business-as-usual projections and could achieve up to 41% emission reduction with international support. Two years later, Indonesia adopted the National Action Plan Addressing Climate Change (RAN-P). The plan offers an integrated development strategy aimed at achieving the emission reduction targets announced by the president. In the energy sector, the plan proposes to increase the use of geothermal and renewable energy, and contemplates deploying CCS to remove up to 40% of power sector emissions.

The other three countries have also begun to frame national climate response strategies. In 2008, Viet Nam adopted the National Target Program to Respond to Climate Change (NTP-RCC), which seeks to assess climate impacts, develop feasible response actions, and identify opportunities for transitioning to a low-carbon economy. It has unveiled the Support Program to Respond to Climate Change, designed specifically to support implementation of the NTP-RCC. Over the last 5 years (2008–2012), Thailand has been implementing its National Strategic Plan on Climate Change 2008–2012. That effort offers a comprehensive national framework for responding to climate change and is centered on six objectives: adaptation, mitigation, research and development, awareness, local climate-related capacity building, and international negotiations.

In the Philippines, the government has begun to position its policy on supporting a transition to a low-carbon economy, centered on implementing its flagship program, the Low Carbon Future Program. This program seeks to develop and promote alternative fuels, sustainable transport, natural gas, renewable energy, and energy efficiency. The Philippines also enacted the Climate Change Act in 2009, which created a Climate Change Commission to coordinate efforts to address the vulnerability of the Philippine archipelago to floods, droughts, and natural disasters in a world increasingly prone to climate change (National Communications 2009).

Although carbon capture and storage (CCS) is not explicitly discussed in the national plans (with the exception of Indonesia), the technology could be a meaningful addition to the national plans. CCS can deliver deep cuts in emissions from coal- and gas-fired power plants, natural gas processing and fuel transformation facilities, and industrial facilities such as iron and steel, chemicals, and cement. CCS could provide the countries with an emissions mitigation strategy that recognizes their need to continue to rely on fossil fuels into the medium and long term, even as they explore low-carbon strategies and make efforts to balance economic growth and environmental stewardship.

2.4 Overview of Carbon Capture and Storage Technology

2.4.1 Introduction

On the one hand, although CCS has yet to be widely deployed, several of its process components are commercially available and proven at a scale required for technology deployment. On the other hand, commercial deployment of *integrated* CCS that brings together capture, transport, and storage must be more widely demonstrated. Concerns about the permanence and safety of CO_2 storage, along with uncertainty about economic performance stemming from the lack of experience with large-scale applications of integrated CCS plants (particularly in power projects), have emerged as the primary barriers to more widespread deployment of CCS. First-of-a-kind (FOAK) integrated CCS demonstration projects have had significantly higher costs than earlier estimates of major cost studies.

A Global CCS Institute 2011 survey shows that 74 large-scale integrated projects (LSIPs) for CCS are being actively considered around the world. Of these, 15 projects have entered operation or are under construction (Global CCS Institute 2011b). These 15 projects represent a total CO_2 storage capacity of approximately 33 Mt a year (Global CCS Institute 2011b). Eight of these 15 projects are currently operating and all use precombustion capture technology to capture CO_2 from low marginal abatement cost industrial sources. These include six natural gas-processing plants, one fertilizer plant, and one coal-to-syngas plant. Two of the projects currently under execution include CCS on power plants. Table 2.1 (Global CCS Institute 2011b) lists the plants that are currently operational or under construction.

No CCS project has yet been identified in Southeast Asia, although several countries in the region have become interested in the possibilities. Indonesia, for example, has been examining its enhanced oil recovery (EOR) potential since 2003 (Indonesia CCS Working Group 2009). Among the CCS with EOR projects listed in Table 2.1, it should be noted that only two of these (plus the deep saline aquifer

Table 2.1 **Operational and Under-Construction Carbon Capture and Storage Plants**

Name	Location	Capture Type	Volume CO_2 (MTPA)	Storage Type
Operational Stage				
Shute Creek Gas Processing Facility	United States	Precombustion (gas processing)	7	EOR
Val Verde Natural Gas Plants	United States	Precombustion (gas processing)	1.3	EOR
Great Plains Synfuels Plant and Weyburn-Midale Project	United States/ Canada	Precombustion (synfuels)	3	EOR with MMV
Enid Fertilizer Plant	United States	Precombustion (fertilizer)	0.7	EOR
Century Plant	United States	Precombustion (gas processing)	5 (and 3.5 in construction)	EOR
Sleipner CO_2 Injection	Norway	Precombustion (gas processing)	1	Saline aquifers
Snøhvit CO_2 Injection	Norway	Precombustion (gas processing)	0.7	Saline aquifers
In Salah CO_2 Storage	Algeria	Precombustion (gas processing)	1	Saline aquifers
Execution Stage				
Lost Cabin Gas Plant	United States	Precombustion (gas processing)	1	EOR
Illinois Industrial Carbon Capture and Sequestration (ICCS) Project	United States	Industrial (ethanol production)	1	Saline aquifers
Kemper County IGCC Project	United States	Precombustion (power)	3.5	EOR
Gorgon Carbon Dioxide Injection Project	Australia	Precombustion (gas processing)	3.4–4	Saline aquifers
Boundary Dam with CCS Demonstration	Canada	Post-combustion (power)	1	EOR with MMV
Agrium CO_2 Capture with Alberta Carbon Trunk Line (ACTL)	Canada	Precombustion (fertilizer)	0.6	EOR
Shell's Quest Project	Canada	Amine solvent (oilsands hydrogen manufacturing units)	>1	Saline aquifer

CCS = carbon capture and storage; EOR = enhanced oil recovery; IGCC = integrated gasification combined-cycle; MMV = measurement, monitoring, and verification; MTPA = million ton per year.

Source: Global CCS Institute (2011b).

CO_2 injection projects) undertake measurement, monitoring, and verification (MMV) for CO_2 storage and as such meet climate change abatement goals. If MMV is undertaken with the objective of CO_2 storage in the other remaining CCS EOR projects, then these projects will also be able to qualify as genuine CO_2 abatement projects in compliance with rules adopted by the United Nations Framework Convention on Climate Change.

2.4.2 Technology

CCS is the only technology that can achieve deep reductions in CO_2 emissions from the use of fossil fuels in power plants and other industries. The CCS process involves four key components:

(i) Capture stage: capturing, dehydrating, and compressing CO_2 from large stationary emission sources

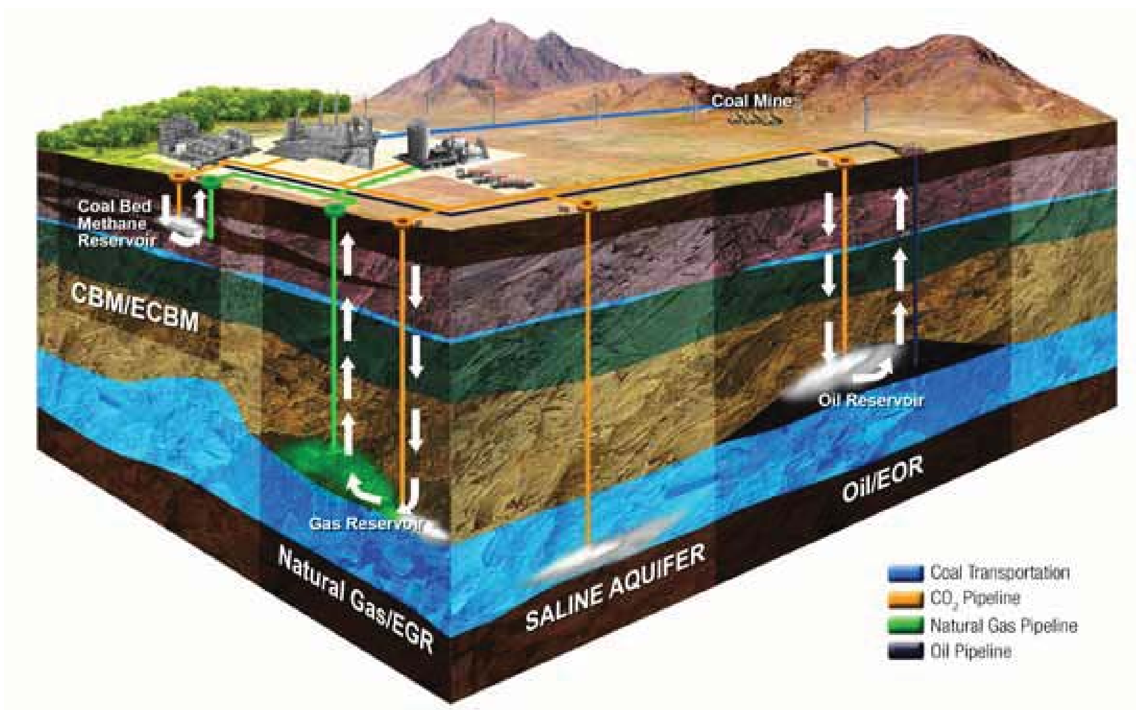
(ii) Transport stage: transporting CO_2 by tankers, pipeline, or ship to a suitable storage site

(iii) Storage stage: injecting CO_2 deep underground for secure and permanent storage

(iv) Measurement, monitoring, and verification (MMV): for secure and permanent storage underground.

Figure 2.3 illustrates a simplified schematic of the overall CCS process. The figure provides a very simple representation of capture using a coal-fired power plant, a gas-processing plant, and an oil refinery as examples of CO_2 capture facilities. The CO_2 is collected from the power plant, the gas plant, and the oil refinery and injected into conventional depleted oil and gas fields for enhanced oil recovery (EOR) and enhanced gas recovery (EGR), in addition to enhanced coal bed methane recovery (ECBM). As noted in the discussion surrounding the CCS EOR projects listed in Table 2.1, CO_2 utilization for EOR and ECBM alone, without MMV and operations designed to also promote CO_2 storage underground, will not meet GHG abatement objectives. When CO_2 utilization for EOR, EGR, and ECBM is combined

Figure 2.3 **Carbon Capture and Storage Schematic Showing Oil and Gas Production, CO_2 Utilization in Resource Production, and CO_2 Storage**



CBM = coal bed methane, ECBM = enhanced coal bed methane, EGR = enhanced gas recovery, EOR = enhanced oil recovery.
Source: ADB.

with verified storage, then the overall CCS EOR, EGR, and ECBM scheme will meet climate change objectives. A primary advantage of utilization and storage in EOR, EGR, and ECBM schemes is that the revenue recovered from incremental oil and gas production is able to partially defray the overall cost of CCS.

2.4.3 Capture

CO_2 in flue gas can be separated and captured from a number of stationary emission sources, such as fossil fuel power plants, cement production, refineries, natural gas processing, steel plants, and biomass plants. In some of these sources, such as natural gas–processing plants where CO_2 needs to be separated from raw gas for producing sales-quality natural gas, CO_2 separation is already a standard part of the process. Captured CO_2 needs only to be dried and compressed before transportation and storage.

Capture from Power Plants

Three main processes have been developed for capturing CO_2 from fossil fuel power plants: (i) post-combustion capture, (ii) precombustion capture, and (iii) oxyfuel (IPCC 2005). These three schemes are shown in the upper section of Figure 2.4.

Post-combustion capture separates CO_2 from the flue gas from the combustion process. CO_2 from the flue gas is absorbed by chemical solvents, such as amines or chilled ammonia. After the absorption, the CO_2-rich solvent is heated and regenerated before recycling back to the next absorption cycle, while pure CO_2 released from the solvent can be separated, dried, and compressed for transportation.

Precombustion capture separates CO_2 before the combustion process. In a precombustion process, fuels (such as coal, natural gas, or biomass) are gasified (steam reforming or partial oxidation in the case of natural gas) to produce carbon monoxide (CO) and hydrogen and subsequently shifted in a water gas shift reactor to CO_2 and hydrogen at high temperature and high pressure, before the CO_2 is separated using a solvent capture unit. A typical precombustion capture application with coal or oil is in an integrated gasification combined-cycle (IGCC) power plant. Hydrogen after CO_2 separation is combusted in a gas turbine to generate electricity, while residual heat from the combustion process is used to generate electricity in a steam turbine. The CO_2-rich stream released from the shift reactor is separated by physical solvent, dried, and compressed for transportation.

Oxyfuel combustion is a process whereby fuels are combusted in a mixture of oxygen and recycled carbon dioxide rather than with air, as is the case in a conventional thermal power plant. Therefore, flue gas has a much higher concentration of CO_2, which makes CO_2 separation easier. However, this process requires additional capital investment and energy use due to the separation of oxygen from air in the front-end air separation units.

Capture from Industrial Sources

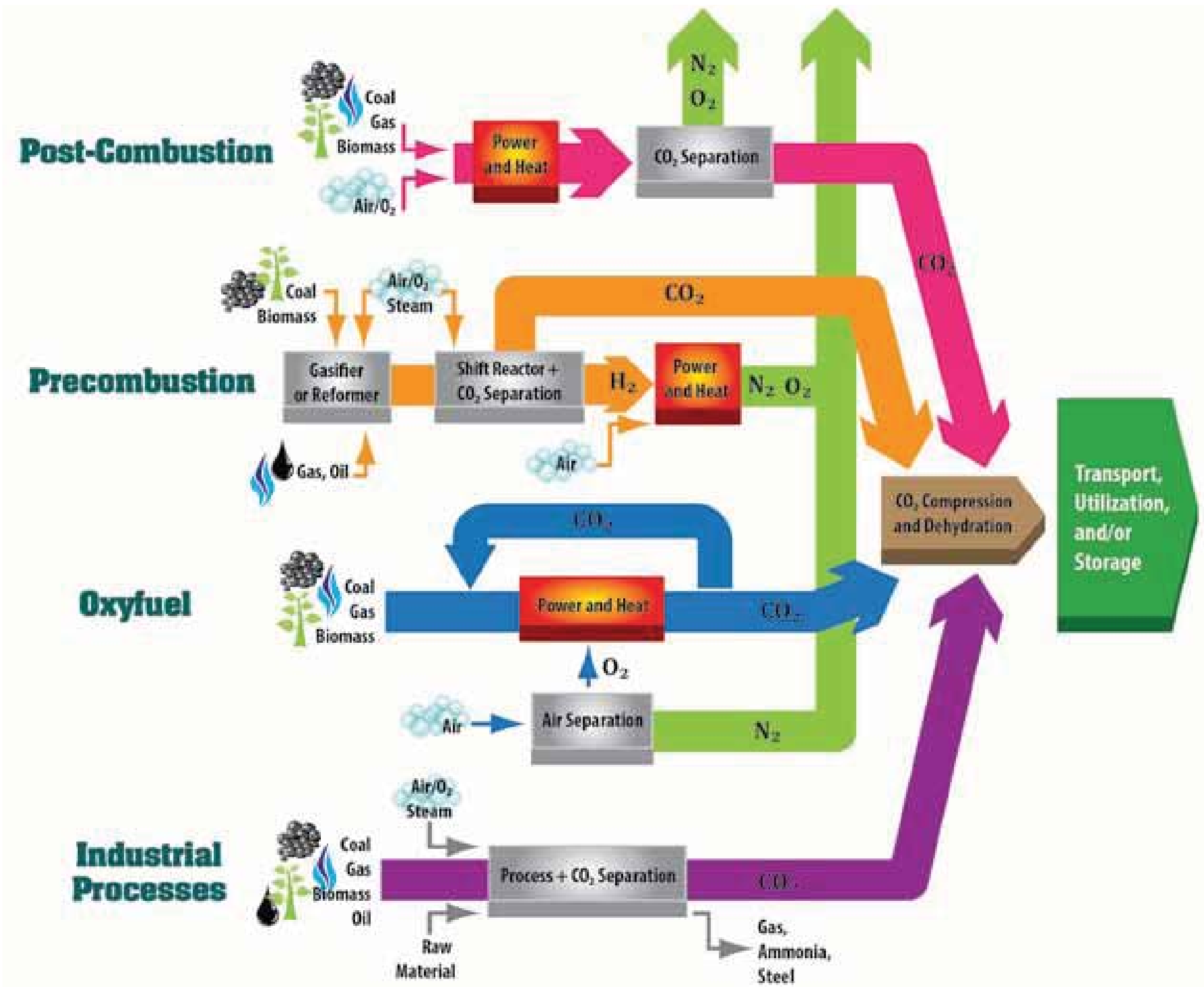
The fourth scheme shown in the bottom of Figure 2.4 is meant to illustrate the application of capture in an industrial process where the product is produced using fossil fuels or where process emissions of GHG are large, e.g., cement, fertilizers, refineries, etc. Depending on the product and the process used in manufacture, capture of CO_2 is primarily undertaken using one of the three main capture processes described earlier in the context of their application in power plants, i.e., post-, pre-, or oxyfuel combustion.

It is worth mentioning that post-combustion capture, i.e., CCS retrofit or in new plants, was considered the most applicable system because it involves very minimal changes in the combustion process of existing or new power plant facilities. A precombustion capture system, on the other hand, is recommended to be adapted to new power plants (brownfield and greenfield power projects) that are planned for construction starting in 2020. New or retrofit plants for oxyfuel combustion were not considered, since the technology has not reached maturity in commercial-scale applications, though they have been demonstrated in smaller-scale plants.

2.4.4 CO_2 Transportation Options

Captured and compressed CO_2 can be transported to storage sites by tanker trucks, pipeline, or ship. CO_2 tanker trucks and pipeline transportation are already a mature technology. Approximately 5,800 km

Figure 2.4 **CO_2 Capture Process**



CO_2 = carbon dioxide, H_2 = hydrogen gas, N_2 = nitrogen gas, O_2 = oxygen gas.
Source: ADB.

(3,600 miles) of CO_2 pipeline operate in the United States (Parfomak et al. 2009). Ship transportation is an alternative option providing flexibilities in matching capture and storage sites.

Similar to LNG and crude oil transport, there is often an economic trade-off to transporting by ship versus pipeline which depends on distance. In some pilot-scale projects, CO_2 can be transported by tanker trucks by road or rail to sites for storage or utilization.[7] However, truck and rail are unlikely to be an economically viable option for transporting large amounts of captured CO_2.

2.4.5 CO_2 Storage and Utilization Options

Captured CO_2 can be injected for storage in deep geological formations (such as mature or depleted oil and gas fields), deep coal seams that cannot be mined, and saline aquifers. Injected CO_2 will be stored

[7] For example, trucks are used to transport 100,000 tons of CO_2 per year from the capture plant in the Shenhua (People's Republic of China) coal-to-liquid project to the CO_2 injection site.

as a dense phase supercritical fluid and could be trapped through a number of different mechanisms, such as structural and stratigraphic trapping, residual gas trapping, solubility trapping, mineral trapping, and hydrodynamic trapping.

Depleted Oil and Gas Fields

Injecting CO_2 into mature or depleted oil and gas fields can benefit from the proven integrity of the reservoir and the adequacy of the permeability, as well as save time during the site characterization process. The estimated global storage capacity of depleted oil and gas fields is limited in contrast to saline aquifers, while additional wells (e.g., exploration and production wells) drilled and not adequately sealed may increase the risk of leakage, as well as increase monitoring costs, which could be offset by the existing oil and gas infrastructure.

Injecting CO_2 into oil fields as a last and final tertiary recovery technique for producing incrementally more oil has been applied in North America since the early 1970s. The CO_2 dissolves in the oil, lowering its viscosity and causing it to swell, as well as providing a pressure drive to move the oil to the production wells. Combining CO_2-EOR with storage could result in an average additional oil production of approximately 12% of the original oil in place, if the CO_2 is completely miscible with the oil. This is one of the most attractive options for transitioning to geological storage of CO_2, since approximately 40% of the CO_2 injected remains behind in the reservoir after it has displaced the oil.

Enhanced natural gas recovery is at the pilot testing stage, though this process has been plagued by concerns about the breakthrough of CO_2 into the produced natural gas because CO_2 and natural gas have similar physical properties (Pooladi-Darvish et al. 2008). The combination of CO_2 storage with enhanced oil or gas recovery from mature reservoirs can generate additional revenue through extra oil or gas production.

Deep Coal Seams or Coal Seams That Cannot Be Mined

Captured CO_2 can be injected into deep or uneconomic coal seams for permanent storage. Once CO_2 is injected, the coal seam can no longer be mined. Similar to EOR, CO_2 could also be injected to enhance coal bed methane recovery. However, most of the coal seams in the world have low permeability, which is detrimental to the injectivity of the CO_2 into the seams, as sorption of the CO_2 causes the coal to swell and reduces the permeability further. This is one of the main barriers to overcome in the implementation of ECBM technology. Shale gas may offer a similar opportunity.

Saline Aquifers

Saline aquifer formations have the most significant geological storage potential due to their ubiquitous occurrence in all sedimentary basins. CO_2 can be injected into saline aquifers for permanent storage. Large-volume regional saline aquifers have formed the conduits for transport of oil and gas over geologic time to the current stratigraphic and structural traps where they now form economic petroleum deposits. If residual trapping of CO_2 is proved for storage in saline aquifers, then the volume of CO_2 that may be stored in unconfined saline aquifers is unlimited because stratigraphic and structural traps are not required.

Other Utilization

Besides EOR and ECBM (as described), captured CO_2 can be potentially utilized in other applications, such as for recovering methane hydrates, growing algae for biomass production, and producing bulk chemicals (DNV 2011). The utilization of CO_2 can have different impacts on net GHG emissions based on how quickly it is re-released back into the atmosphere from product degradation or stored permanently, and from any additional use of energy for its biological or chemical transformation. For example, in the case of CO_2 utilization in the growth of algae, solar energy assists biological transformation without the net release of additional carbon emissions. In the case of utilizing CO_2 to produce chemicals, energy use for its transformation must come from a renewable and not from a fossil energy source to minimize CO_2 release to the atmosphere. Hence, it is important to understand that the ability to supply large fluxes of renewable energy to efficiently utilize large quantities of CO_2 through biological and chemical transformation is a barrier that needs to be overcome. In the near term, CO_2 utilization with storage in EOR is a better proven option.

2.4.6 Monitoring, Measurement, and Verification

The aim of monitoring, measurement, and verification (MMV) is to provide the long-term ability to identify and quantify the position of the CO_2 plume, including any leakage from the underground CO_2 storage site. This is accomplished by monitoring at various depths in the geologic column: at the surface (e.g., soil surveys, water wells, seismic, tiltmeters, Eddy Covariance, INSAR, laser spectroscopy, gravity, electromagnetic); the biosphere beneath the surface (e.g., seismic, passive seismic, monitoring wells); the geosphere beneath the biosphere (e.g., seismic, observation wells, well logs); and in the storage reservoir (e.g., seismic, passive seismic, observation wells, well logs, tracers). MMV can also assure the public and regulators that CO_2 has been safely stored, which is necessary for issuing CO_2 credits in compliance with climate change mitigation protocols.

3 Capture Sources

Carbon dioxide (CO_2) emissions arise from a number of stationary and non-stationary sources, consisting mainly of fossil fuel combustion in power generation, industrial processes, oil and gas extraction activity and processing, coal mining, and residential and transport sectors.

For the purpose of evaluating potential carbon capture and storage (CCS) projects, this study focuses on potential CO_2 sources that are technically amenable to CO_2 capture and subsequent transportation to a CO_2 storage site. These sources include power plants, petroleum and gas-processing facilities, cement plants, and fertilizer-producing facilities—all of which are stationary sources. These stationary sources typically account for the largest part of CO_2 emissions and fall under the nine industry types used by the US National Energy Technology Laboratory (NETL) in preparing the US Carbon Sequestration Atlas (NETL 2010a).

3.1 Data Inventory Methodology

For each country, an inventory of emission sources was gathered and collated in two steps: (i) from secondary data sets, and (ii) from questionnaires sent to selected emission sources.

For Indonesia, LEMIGAS provided the bulk of the existing information on the sources as part of a study carried out in 2009 called *National Greenhouse Gas Inventory from the Energy Sector*. For Viet Nam, existing data on power plants were obtained from data from the Institute of Energy. In the case of Thailand and the Philippines, the study focused on CO_2 emissions from gas and oil processing and fossil fuel–powered power stations because these represented the key large emission sources with the most complete data.

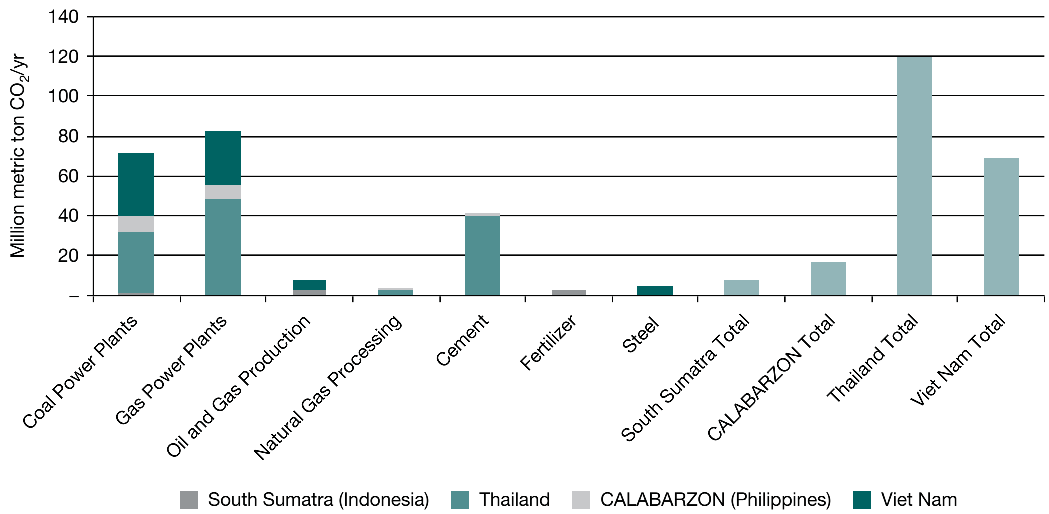
In addition to the secondary data sources, information was compiled through a questionnaire. The questionnaire was sent to the power plants, relevant industrial sources (iron and steel, cement, fertilizer plants), refineries and natural gas–processing facilities. In some instances, data compiled from the questionnaire overlapped with the data from the various partner agencies. In cases where the two sources reported different values on some power plants, the study team exercised expert judgment to ensure that the data were consistent and reflected the real situation as much as known. The combination of these two data sources yielded information about existing facilities.

3.2 Emissions Inventory

The initial inventory from the four countries returned a total of 214 Mt, as illustrated in Figure 3.1. Although the emissions inventory appears skewed toward Thailand and Viet Nam in terms of total CO_2 volume, it is important to bear in mind that the inventory represents different geographic foci. For Indonesia, only sources in South Sumatra were considered because that was the focus of the study. For the Philippines, only sources in the CALABARZON region were considered because it represented the most substantive and meaningful part of national emissions.

The inventory is dominated by emissions from coal and gas power plants, though some of the smaller industrial sources, such as fertilizers and natural gas processing, also offer interesting capture opportunities because of the stream of pure CO_2 they release. Although natural gas–processing facilities represented only 3 megatons (Mt) in total, these facilities offer the best opportunities for capture for pilot projects because of the low cost of capture,

Figure 3.1 **Emissions Inventory of Existing Sources**



the proximity to storage sites, and the availability of existing transport infrastructure.

In addition to the emissions inventory of existing sources, the study also evaluated some prospective sources. Plant-specific details were not available uniformly across the countries and visibility on future plants, outside of the power sector, was limited. Nonetheless, future power plants could be future candidates for emissions capture. Viet Nam is expected to add 48 gigawatts (GW) of power generation by 2025, which, if all were in operation, would add 250 Mt CO_2 by 2025. Thailand expects to add 9.4 GW of thermal power plant capacity by 2020, of which 1.3 GW will be coal, 5.6 GW will be gas, and 2.5 GW cogeneration. Most of the new coal plants in Thailand are likely to be based on the coast and reliant on higher-quality imported bituminous coal.

The Philippines Power Development Plan has identified the need of 14.4 GW of new capacity by 2030. Consistent with the capacity additions, emissions in the sector are expected to increase from 33 Mt in 2010 to 90 Mt by 2030. These future power plants are yet to be fully detailed and could be specifically designed to be CO_2 capture–ready or fitted with CO_2 capture.

Despite opportunities presented by future sources, the study decided to focus on existing sources for the capture-ranking process in all countries, with the exception of Viet Nam. The emissions inventory of existing sources in Viet Nam revealed that future power plants offered far better opportunities than existing, subcritical coal-fired units, and that existing units would need significant upgrade and renovation. Unlike the other countries, details about Viet Nam's future power plants, such as size, location, and technology, were also available.

For Viet Nam, an emissions potential of 325 Mt in 2025 was identified from existing and future sources. The inventory included approximately 35 coal power plants, with annual average emissions of 8 Mt across the plants. The inventory also included four gas power plants with annual average emissions of 7 Mt across the plants. Several smaller industries—steel with 0.5 Mt of total emissions and cement with 1 Mt of total emissions—were also included.

In Indonesia, only sources in South Sumatra were evaluated. The inventory included five facilities: a natural gas–processing facility, a power plant, a cement plant, a fertilizer plant, and a petroleum refinery. With a total emissions inventory of about 8 Mt, the fertilizer plant was the single largest contributor, followed by the coal-fired power plant. Although the northern and central parts of South Sumatra also have several natural gas–processing facilities that could have emerged as strong candidates, adequate data were not available from these plants for evaluation. Although they were not included in this particular analysis, the study recommends that they receive further consideration as more data become available. Although these individually represent lower volume point sources, they do emit substantially higher-purity CO_2 flows per year, which open up the possibility of better long-term supply at lower cost for CCS demonstration or commercial-scale projects and for clustering CO_2 sources.

In Thailand, the inventory included over 50 potential sources for CO_2 capture across four sectors—power, cement, natural gas processing, and oil and gas production—which represented the best capture sources. Collectively, these sources produce approximately 108 Mt per year. The power sector was the largest emitter: gas and coal-based power generation accounted for 35 Mt and 49 Mt per year, respectively. The single largest emission source was a lignite power plant in the north which produced nearly 18 Mt CO_2 per year. The second highest emission source produced less than half of that volume.

In the Philippines, the major CO_2 emission sources identified in the CALABARZON region were three coal-fired power plants, three gas-fired power plants, three cement plants, and an oil refinery.

At this stage of the inventory analysis, the common theme in the results across the countries suggests that natural gas–processing facilities, where available, should emerge as the best choices for initial pilot and demonstration projects. Power plants are likely to the best sources of CO_2 for larger-scale commercial CCS projects. Many new power plants are currently being planned and several existing power plants will need to be modernized or retrofitted in the near future. These power plants could be designed to be CO_2 capture–ready or fitted with actual capture facilities.

The emissions inventory provides a broad sense of the volume available for capture, confirming the view that there are sufficient emission volumes to support the development of CCS in these countries. Following the inventory, the study conducted a more detailed technical, economic, and feasibility assessment of the emission sources to rank the sources by suitability of CO_2 capture. The methodology for the assessment, along with the results, follows.

3.3 Capture-Ranking Methodology

After a comprehensive list of emission sources was compiled, a decision scheme and weighting methodology was developed to prepare a list of candidate sources ranked for suitability for CO_2 capture. The ranked emission sources were subsequently used in the source–sink matching analysis before final recommendations on potential pilot, demonstration, and commercial projects were made.

The study used a source-ranking methodology consisting of an index-based system representing the source's suitability for CO_2 capture. The final index value or score for suitability of capture was then used to rank the sources by relative suitability. A two-step process was used to determine the score for capture. In the first step, plants had to satisfy two qualifying criteria. These included: (i) remaining operating life of at least 20 years, and (ii) plants must have limited operational variability (i.e., exceed an 80% operating factor) so that a steady stream of CO_2 is produced. Only plants that met these qualifying criteria were examined further in the second step.

The second part of the ranking methodology involved 11 preferential criteria covering a broad range of related technical, location, and readiness factors, as illustrated in Table 3.1. All preferential criteria were not equally important. Each criterion was given a weight that reflects its relative importance in the set of criteria.

The CO_2 sources that met the first set of qualifying criteria were then measured against the preferential criteria. The qualifying sources were provided a score ranging from 0–10 to indicate how well they measured on each preferential criterion. In some cases where the criterion was a discrete indicator, e.g., the existence of post-combustion controls, the score was a binary value of 0 or 10. When the criterion was a continuous indicator, a score between 0 and 10 was provided to reflect where it fell within that score range.

For each potential source, a composite index value was developed by (i) multiplying the score for each criterion with the weight for that criterion (i.e., weighted score); and then (ii) for each source, the weighted score achieved against each of the criterion

Table 3.1 **Weights for the Preferential Criteria**

Preferential Criterion	Description	Relative Weight
Source stream CO_2 concentration*	Higher is better; 100% is ideal	10
Space availability	Adequate space for capture equipment	10
Availability of post-combustion controls (FGD, ESP, bag filter, cyclone filter)	Preferred to reduce pre-cleaning costs	9
Existing infrastructure (e.g., pressure pipeline, adequate water)	Preferred	9
Readiness of the facility to accept CCS technology	High readiness preferred to maximize capture efficiency	8
Flue gas CO_2 volume	More is better; generally, less than 300,000 tons per year of CO_2 will not be efficient	7
Source stream SO_x concentration*	Lower amount is better to avoid more intensive pre-cleaning	7
Source stream NO_x concentration*	Lower amount is better to avoid more intensive pre-cleaning	6
Emission source life (minimum: 20 years)	Longer is better	5
Stability of emission load (minimum: 80%)	Higher operating factor is better	4
Willingness of the facility to get involved in CCS activities	High interest preferred to improve chances of success	3

CCS = carbon capture and storage, ESP = electro-static precipitator, FGD = flue gas desulfurization, NO_x = mono-nitrogen oxide, SO_x = sulphur oxide.

* Criteria most relevant to the use of post-combustion capture particularly in power and cement plants.

Source: ADB study team.

was totaled to obtain the total weighted score for that source. This total weighted score was then normalized to 100. This final index value or final score for capture suitability was used to rank the sources.

3.4 Source Ranking for Capture Suitability

Not all of the units identified in the previously discussed inventory were ranked for capture suitability. Only plants that passed the qualifying criteria were further evaluated in the ranking round. The total emissions from the ranked sources across the four countries are illustrated in Figure 3.2. The illustration also highlights the final scores the sources achieved on capture suitability and the number of sources in each of the categories. In the discussions, a source is used to mean a plant or facility, though a plant may contain several units each with distinct emissions streams.

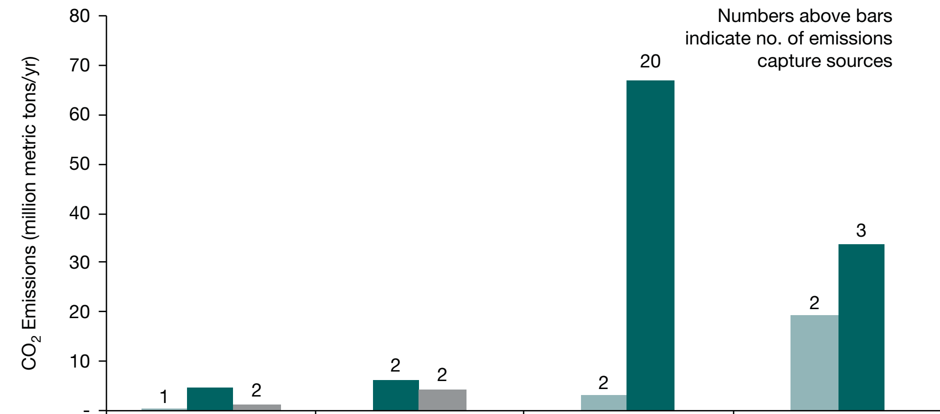
As part of the analysis, the ranking process was subjected to several sensitivities, where small changes in weights and scores were introduced. The overall rankings remained unchanged, suggesting that the overall score for capture suitability was robust and not overly influenced by any subjectivity introduced in the determination of scores or the weights.

The top three candidate sources that received the highest score for capture suitability are summarized in Table 3.2. Candidate capture sources are discussed by country.

In South Sumatra (Indonesia), a natural gas–processing facility emerged as the most suitable CO_2 source for an early CCS pilot project, even though it scored low on CO_2 emission volume (i.e., 0.1 Mt CO_2/yr). Larger sources will need to be used for a later demonstration project. A coal-fired power plant and a fertilizer plant were ranked as medium suitable, while a cement plant and refinery were found to be least suitable. The power plant, fertilizer, cement, and refinery plant together account for nearly 5.4 Mt of CO_2 emissions per year in the South Sumatra region.

The natural gas–processing facility identified in South Sumatra could support a pilot project with an

Figure 3.2 **Emissions and Number of Sources Evaluated for Capture Suitability Ranking**



	South Sumatra (Indonesia)	CALABARZON (Philippines)	Thailand	Viet Nam
Best Ranked (70–100)	0		3	19
Medium Ranked (50–70)	4	6	67	34
Lowest Ranked (0–50)	1	4		

Capture Suitability Ranking (Score, max100)

Best Ranked (70–100) Medium Ranked (50–70) Lowest Ranked (0–50)

Note: Viet Nam reflects emissions from future sources, with projected emissions in 2015. All other countries reflect emissions from existing sources.

injection rate around 363 metric tons of CO_2 per day, substantially higher than the usual pilot project of 50–100 metric tons of CO_2 per day. If combined with other gas-processing plants in the region, it could support a CCS demonstration project with capture and injection volumes of 500–2,700 metric tons of CO_2 per day. However, the current CO_2 output volume on its own is not adequate for a larger demonstration project that will follow the pilot project. If the processing capacity of this natural gas facility is scaled up through some technical modification, such as reducing the stream temperature of the raw natural gas feed to the CO_2 absorbers, it could generate sufficient volume for a demonstration project but not a commercial storage project. Consequently, if South Sumatra were to proceed with the gas-processing facility for the pilot, clustering several other CO_2 sources or emissions from a coal power plant may be required to have enough CO_2 to support a full-scale commercial project in the future.

Most of Thailand's best capture sources are located in the south, with a few dispersed in the north. The top 22 sources, including the top 12 presented in Figure 3.2, were predominantly natural gas combined-cycle (NGCC) power plants along with a few natural gas–processing plants and three coal-based plants. The two gas-processing facilities in central and south Thailand were evaluated to be the most suitable sources for demonstration projects because of their high CO_2 emission rates and CO_2 purity, and the presence of existing infrastructure (high-pressure gas pipelines connecting the plant to the producing fields). Large point sources like the lignite-based power plant in the north scored relatively low on account of the lower purity of CO_2 emissions. Replacing or repowering older parts, such as the northern lignite power plant complex may provide another opportunity for CO_2 capture.

All of the potential emission sources in the Philippines were power plants. A shallow water gas platform, oil refinery, and the three cement manufacturing plants did not meet the qualifying criteria and were not considered further. The four candidate capture plants that were evaluated during the ranking analysis were a coal-fired power plant (500 MW) and three gas-fired power plants (totaling 2,700 MW).

Table 3.2 **Top Three Ranked Capture Candidates by Country**

Country	Location	Plant Type	Emissions (Mt CO_2/yr)
Indonesia (South Sumatra)	South	Natural gas processing	0.1
	South	Subcritical pulverized coal power plant	1.8
	South	Fertilizer (urea) plant	2.7
Philippines (CALABARZON)	Batangas	Natural gas combined-cycle	1.4
	Batangas	Natural gas combined-cycle	3.1
	Batangas	Natural gas combined-cycle	2.8
Thailand	Central	Natural gas processing	2.0
	South	Natural gas processing	0.9
	Central	Supercritical coal (bituminous) power plant	3.1
Viet Nam	Dong Nai Province*	Natural gas combined-cycle	2.2**
	Binh Thuan Province	Future plant (2013–2016), subcritical domestic coal power plant	15.2**
	Ha Tinh Province	Future plant (2012), subcritical domestic coal power plant	4.0**

Mt CO_2/yr = million tons of carbon dioxide per year; CALABARZON = CAvite, LAguna, BAtangas, Rizal, and QueZON.

* In November 2011, a unit in the facility started up subsequent to the CO_2 source evaluation conducted for this study. That unit would also be a likely candidate for CO_2 capture.

** Projected emissions in 2015.

Based on the ranking methodology, a NGCC power plant with 3 Mt/yr CO_2 emerged as the most suitable for capture, followed by the two other NGCC plants (3 Mt/yr CO_2 and 1 Mt/yr CO_2) and then the coal power plant (3 Mt/yr CO_2) in that order. The four candidate power plants, however, need to be retrofitted within the next 10 years (before 2020), at which point their remaining life would still be at least 20 years.

The analysis for the Philippines also included an examination of future capture sources and an assessment of coal- and gas-fired capture plants from a list of planned capacity additions through 2030. Of the 22 coal- and gas-fired future power plant projects totaling 6,455 MW, only one natural gas power plant, with estimated CO_2 emissions of 1.5 Mt/yr, met the conditions to be considered a candidate for capture by 2020.

Viet Nam's ranked CO_2 capture sources include only future coal and natural gas–based power plants located in the southern part of the country and expected to come online between 2012 and 2016. Future coal-based power plants are likely to be subcritical (if based on domestic coal) and supercritical (if based on imported coal). None of the existing facilities have favorable characteristics to contribute to pilot and commercial-scale CCS projects. The four subcritical coal power plants will collectively contribute nearly 19 Mt of CO_2 annually by 2015. Only one NGCC power plant made the list of the ranked emission capture sources.

Future natural gas–processing facilities in Viet Nam could be an important source for capture in the country. Currently in Viet Nam, existing natural gas–processing facilities do not strip CO_2, relying instead on the blending of low- and high-CO_2-content natural gas streams to meet specifications in the natural gas sold to market. As existing fields become depleted, the country will move toward production from new gas fields that involve much higher CO_2 content natural gas. The gas-processing facilities that are subsequently built to strip the CO_2 will afford a low-cost, high-volume, high-purity CO_2 emission stream that is amenable to capture and storage. In the future, when CO_2 separation from high-CO_2-content natural gas sources becomes mandatory, gas-processing plants will likely emerge as sources better suited for capture than power plants, just as in Thailand and Indonesia.

4 CO_2 Storage Capacity

Indonesia, the Philippines, Thailand, and Viet Nam occupy a unique geography that distinguishes them from other parts of the world where carbon dioxide (CO_2) storage is also being considered. The region is composed of over 170 sedimentary basins and is located in an area that is tectonically very active. Two of the countries are complex archipelagos.

Oil and gas have been discovered in the region and are being actively produced. Offshore locations, where most of the storage opportunities reside, are busy waterways with large commercial sea traffic. The region has a large resource base of nonconventional energy and mineral sources, such as geothermal, ophiolites, and coal bed methane, which could offer new possibilities for CO_2 storage. The CO_2 storage capacities in these four Southeast Asian countries were evaluated against the backdrop of their unique geography and diversity of storage options.

4.1 Methodology

In this study, CO_2 storage capacities were evaluated for saline aquifers, oil and gas fields, coal seams, geothermal fields, and ophiolites. In Thailand and Viet Nam, the assessment was countrywide, though some data limitations restricted uniform assessment across the countries. In Indonesia, the assessment was confined to the mature South Sumatra sedimentary basin. Since the development of the oil and gas industry in the Philippines lags behind the other three countries, storage options related to geothermal and ophiolites were also assessed.

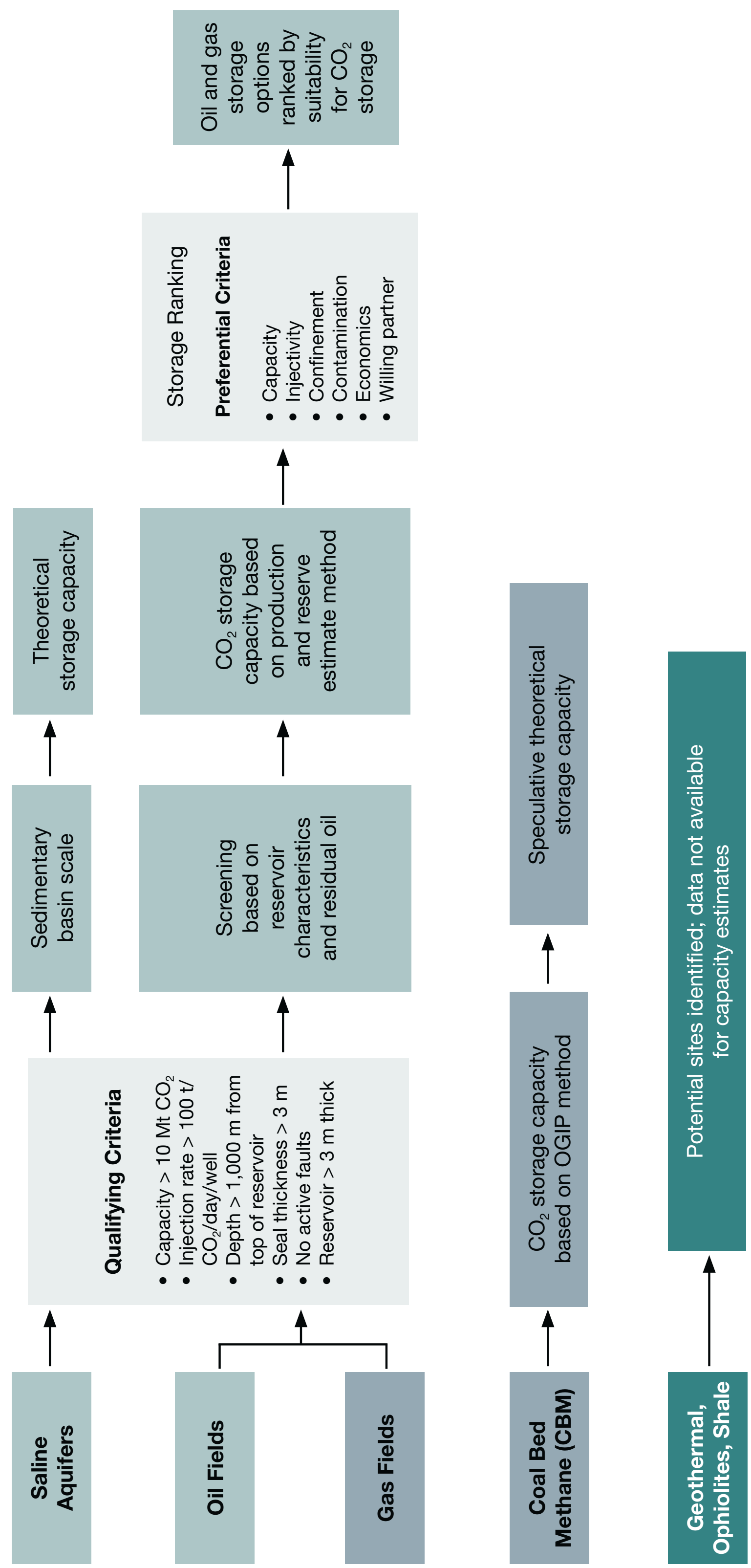
Analogous to the terminology for characterizing petroleum resources and reserves, CO_2 storage is also discussed in terms of a tapering volume of storage potential from theoretical capacity to matched capacity (Bradshaw et al. 2007). The theoretical capacity represents the physical limit of what the geological system can store. Matched capacity, at the other extreme, represents the smallest estimate and corresponds to the detailed matching between source and storage site. Between the two extremes, physical attributes of the storage site (e.g., injectivity, competency of the seal) along with practical considerations (e.g., technical, legal, regulatory, economic) are used to narrow uncertainty around the estimates.

The scale of the data also influences the certainty of the estimates. Saline aquifers were assessed at the basin level and offer theoretical storage estimates. When more detailed data become available, as with oil and gas and coal fields, estimates of effective or practical geological storage capacity can be developed depending on the extent of the data available. Storage estimates in oil and gas fields are the least uncertain because they are assessed using actual production and reserve data and can provide detailed visibility into the reservoir characteristics. Storage estimates of oil and gas fields, therefore, represent effective capacity.

The data for the storage assessments come from the petroleum industry, based on exploration and development activity in the sedimentary basins involving seismic surveys, drilling, and production. This data can also provide relevant information into the maturity of resource development, future plans, potential size of undiscovered resources, the CO_2 content of natural gas fields, enhanced oil recovery (EOR) potential, and other relevant legal and jurisdiction issues.

Storage capacity estimates were developed using a tiered approach with the best available data sets. The approach is broadly illustrated in Figure 4.1. Developing the estimates was focused primarily on saline aquifers, and oil and gas fields. Ranking for suitability of CO_2 storage was conducted only for oil and gas fields because the provided production data allowed detailed assessment of the reservoir characteristics. These oil

Figure 4.1 Approach for Estimating CO_2 Storage Capacity



CO_2 = carbon dioxide, m = meter, Mt = megaton, OGIP = original gas in place, t = ton.

and gas fields offer the best initial storage options, with significant opportunity for EOR. Storage estimates were also developed for coal bed methane, though these estimates are more speculative as commercial production does not exist in Southeast Asia at the moment. Several specific geothermal and ophiolite sites were identified in the Philippines as having storage potential but sufficient data were not available to develop storage capacity estimates.

Storage site selection involved two methodologies. First, qualifying criteria were set up for screening sites. Only potential storage sites that met the qualifying criteria proceeded to the next stage of the analysis. In some instances, complete data were not always available. For those, moderated qualifying criteria were used to take account of data availability.[8] For oil and gas fields, a further set of preferential criteria were used to rank the sites for suitability of storage. The methodology for ranking the oil and gas fields by suitability of storage is discussed in Section 4.3.

Storage estimates for saline aquifers were based on volumetric analysis of sedimentary basins below 1,000 meters of depth. Average pore space volumes were used to calculate a maximum CO_2 occupancy assuming average temperatures and pressures for the aquifers. An efficiency factor (multiple between 0 and 1) was applied to account for the uncertainty in the heterogeneity of the saline aquifer. For Indonesia, the Philippines, and Thailand, an efficiency factor of 0.01 was used. A more stringent efficiency factor of 0.001 was used for Viet Nam.

Storage estimates of oil and gas fields represent effective storage capacity. These estimates were based on the estimated ultimate recovery (EUR) of oil and gas. The data required for this estimation included cumulative production for oil, water, and gas for each field, including volume of water injected (when available), reserve estimates, formation volume factors, initial reservoir temperature and pressure, field depth, and geographic coordinates. The EURs are converted to CO_2 storage estimates by using formation volume factors and the density of the CO_2 at reservoir conditions.

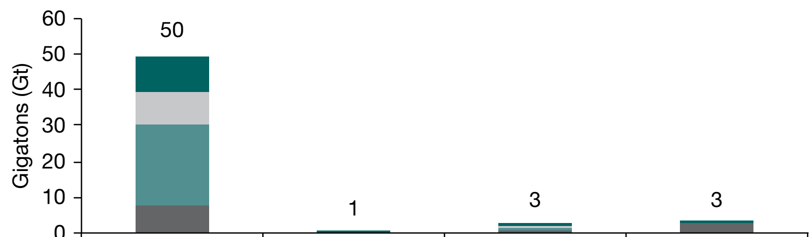
Storage estimates in coal bed methane were based on volumetric analyses of coal beds at depths exceeding 300 meters. The estimate of the original natural gas in place is converted to a CO_2 gas in place. The conversion includes the assumption of a sorption selectivity factor of 2 of CO_2 over methane (CH_4), adjusts for the density of CO_2, and applies an efficiency factor of 0.2.

4.2 Storage Estimate

The initial estimates of this study suggest that the four countries in Southeast Asia have CO_2 storage capacities of approximately 54 Gt, enough to store the entire inventory of 200 Mt CO_2/yr from all the focus areas of this study for over 2 centuries. Of the estimated storage capacity, 88% is located in saline aquifers as illustrated in Figure 4.2. The storage estimates across the different types of geological containers, however, denote varying levels of capacity certainty. Saline aquifers and coal bed methane estimates represent theoretical capacity with a high level of uncertainty in the estimate. Even within the saline aquifer capacity estimates from the four different countries, the uncertainty varies due to the quality of the data available, with the best data coming from Viet Nam and the poorest from the Philippines. While Viet Nam's estimate was based on porosity and structural and stratigraphic trapping, the other three countries' estimates were based on total porosity only. Estimates of CO_2 storage capacity in oil and gas fields for Thailand and the Philippines and the oil fields of South Sumatra were developed using actual production and reserve data from the fields, and they offer a higher level of detail about reservoir characteristics. For the oil and gas fields of Viet Nam and the gas fields of South Sumatra, original oil in place (OOIP) and recovery factors were used, which increases the uncertainty of the storage estimates compared to those made from production and reserve data. The storage capacity of oil and gas fields represents an effective storage capacity or a reserve estimate with a higher level of certainty.

[8] Data were not available for seal thickness, reservoir thickness, or presence of active faults for any of these assessments. Consequently, these qualifying criteria were not used. For the effective storage numbers for oil and gas, it was assumed that seal thickness and reservoir thickness were adequate and no active faults were present since the fields had contained oil and gas over geological time. The capacity criterion of > 10 Mt CO_2 was relaxed when there were several sites in close proximity whose aggregate storage was > 10 Mt. Once a more detailed assessment is done, data collected on seal and reservoir thickness and presence of faults could be used to update this analysis.

Figure 4.2 **Estimated CO_2 Storage Capacity**



	Saline Aquifers (Theoretical Capacity)	Oil Fields (Effective Capacity)	Gas Fields (Effective Capacity)	Coal Bed Methane (Theoretical Capacity)
South Sumatra (Indonesia)	7.7	0.1	0.8	2.7
Philippines	22.7	0.0	0.3	–
Thailand	8.9	0.1	1.3	–
Viet Nam	10.4	0.6	0.7	0.5

CO_2 = carbon dioxide.

Although the estimated theoretical storage capacity in saline aquifers is large, the total theoretical storage capacity in the resource could be much larger. The sedimentary basins of the four countries are illustrated in Figures 4.3–4.6.

The estimate for the theoretical storage capacity in saline aquifers presented in this report is only a partial look at what may be possible as sufficient data did not exist for all the sedimentary basins. Thailand's estimate is based on 10 of the 94 sedimentary basins[9] (Figure 4.5); Viet Nam's on 6 of 8 basins (Figure 4.6); and Indonesia's on 1 of the over 60 basins (Figure 4.3). Estimates for the Philippines were based on only two sedimentary basins (Cagayan and Central Luzon Basin), representing one-eighth of the possibilities (Figure 4.4). Storage opportunities in three geothermal fields and one ophiolite complex were also identified, but sufficient data did not exist to offer specific storage capacity estimates.

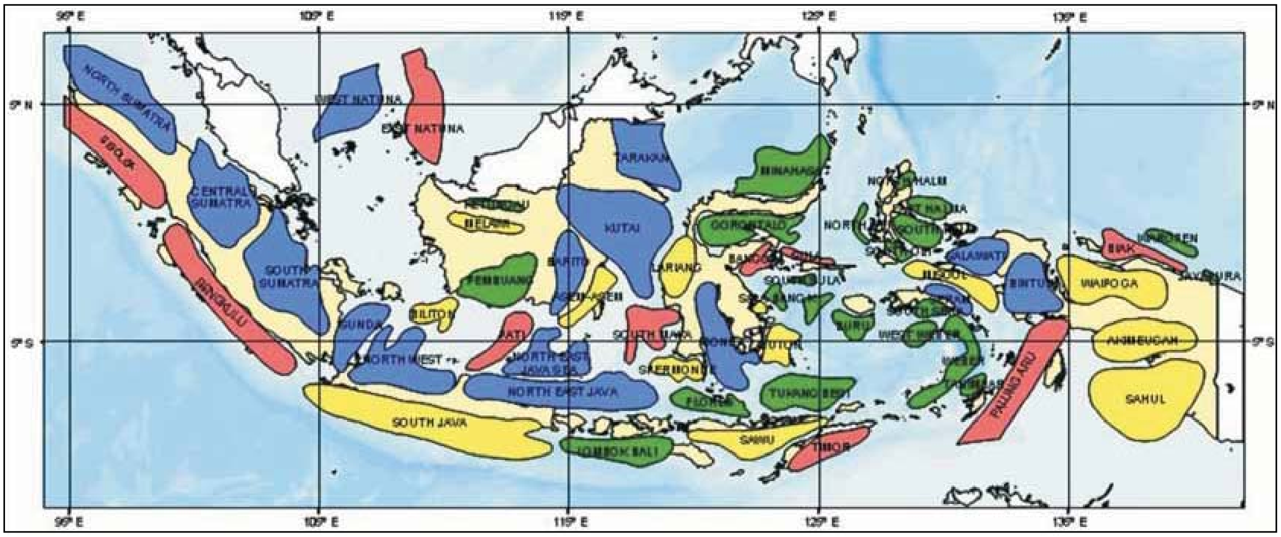
The Viet Nam assessment included only those saline aquifers that were part of the petroleum system and is therefore only a minimum storage estimate. This is the reason a lower efficiency factor of 0.001 (versus 0.01 for the other countries) was used for Viet Nam. The six basins evaluated in Viet Nam included Song Hong, Phu Khanh, Cuu Long, Nam Con Son, Malay–Tho Chu, and Tu Chinh–Vung May. In South Sumatra (Indonesia), the initial estimate was based only on the assessment of the South Palembang, Central Palembang, North Palembang, and Jambi subbasins of the South Sumatra Basin.

Despite being a theoretical capacity estimate, the large storage potential in saline aquifers across the four countries clearly justifies further quantification of the unstudied basins and additional analysis of the identified theoretical storage opportunities. The detailed methodology for the characterization of saline aquifers is described in a recent Canadian Standards Association standard (CSA Z741-12).

Much like EOR, CO_2 can be used to enhance the recovery of natural gas from coal due to its selectivity over methane for sorption on coal. Opportunities for CO_2 storage in coal bed methane (CBM) are available in Indonesia, the Philippines, and Viet Nam. However, sufficient

[9] The 10 basins evaluated in Thailand included Chumpon, Eastern Kra, Fang, Kra, Malay, Nam Phong , Pattani, Pitsanulok, Songkla, and Western Kra.

Figure 4.3 **Sedimentary Basins of Indonesia**



Production Basin

Exploration Basin (drilled basin, no discovery yet)

Development Basin (drilled and proven discovery but no production)

Non-Developed Basin

Source: LEMIGAS.

data to quantify a storage potential were available only for Indonesia and Viet Nam. The estimate for Viet Nam was based on eight blocks of the Ha Noi trough and represents the cumulative theoretical storage potential in depths between 300 and 1,500 meters. The Viet Nam estimate is for only one of the seven CBM areas and could increase substantially as CBM is more extensively developed.

Like Viet Nam, CBM is in an early stage of development in Indonesia. Of the 11 onshore coal basins in Indonesia, the resource in South Sumatra is the largest at around 124 trillion cubic feet (Kumely et al. 2003). The storage estimate of South Sumatra was developed using data from a report by the Asian Development Bank (ADB 2003b) on CBM. As with Viet Nam, this estimate represents a preliminary theoretical estimate but indicates good potential for CO_2 storage in the coals if CBM is commercially developed in the future.

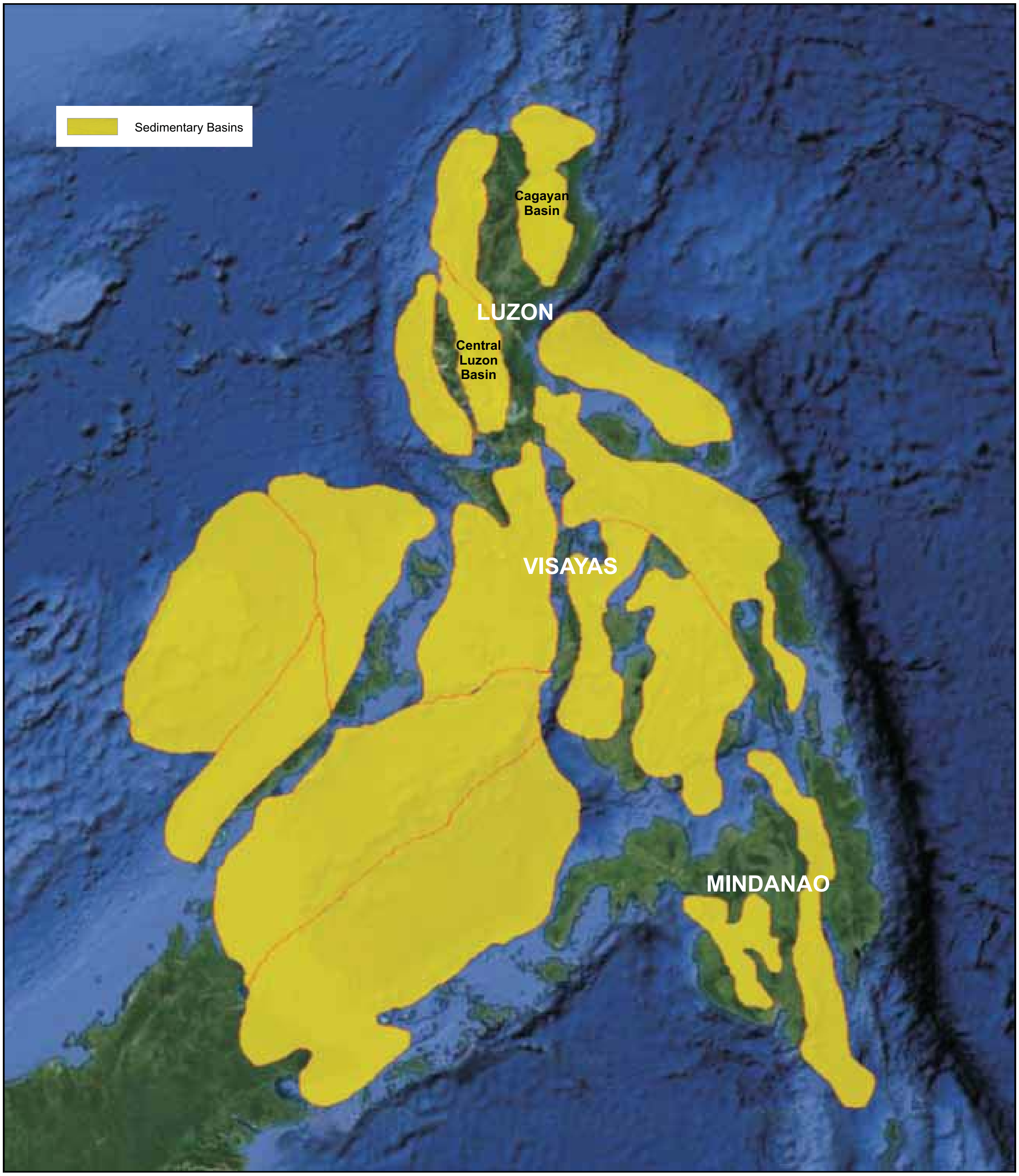
Unlike regional saline aquifers, where each sink option is typically large (often greater than 200 Mt CO_2 and sometimes even exceeding 1 Gt), storage capacity in individual oil and gas fields tends to be much smaller. The distribution of oil and gas fields by their CO_2 storage volume is illustrated in Figures 4.7 and 4.8.

Excluding Viet Nam, more than 85% of the total of potential oil fields assessed for CO_2 storage are fields that will individually hold less than 10 Mt CO_2.

Relative to the oil fields, gas fields offer a wider dispersion of storage sites by CO_2 storage volume. The availability of a few large volume storage options in oil and gas fields could more easily help to facilitate the choice of a storage field for a pilot or demonstration project.

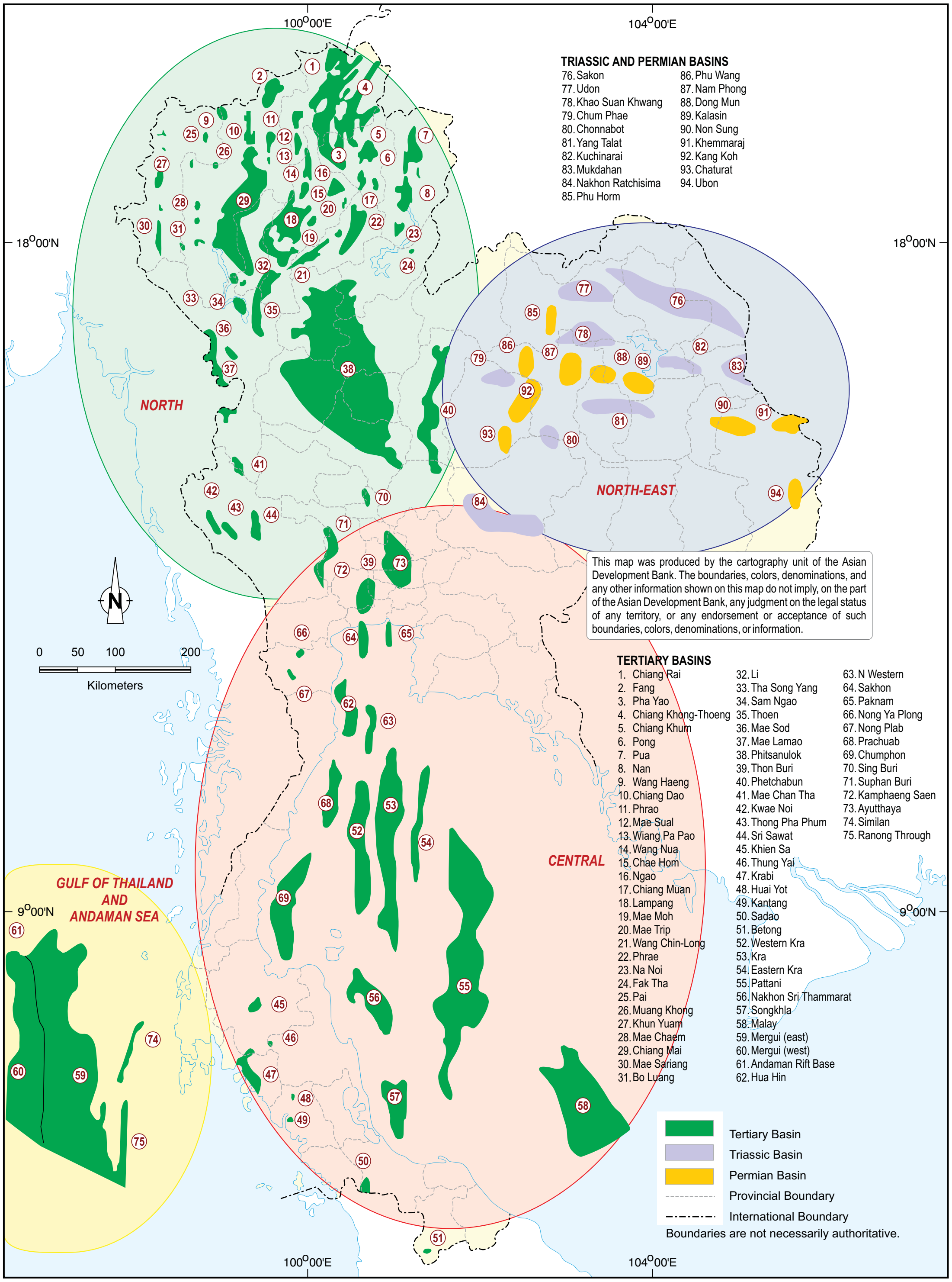
As in the case for saline aquifers and CBM, the estimates for the oil and gas fields represent only a fraction of that capacity in each country because they only represent oil and gas fields that have been discovered and produced or are on production. This would particularly apply to the Philippines where oil and gas exploration is at an early stage. In addition, only 56% of the oil and gas fields in Thailand had

Figure 4.4 **Sedimentary Basins of the Philippines**



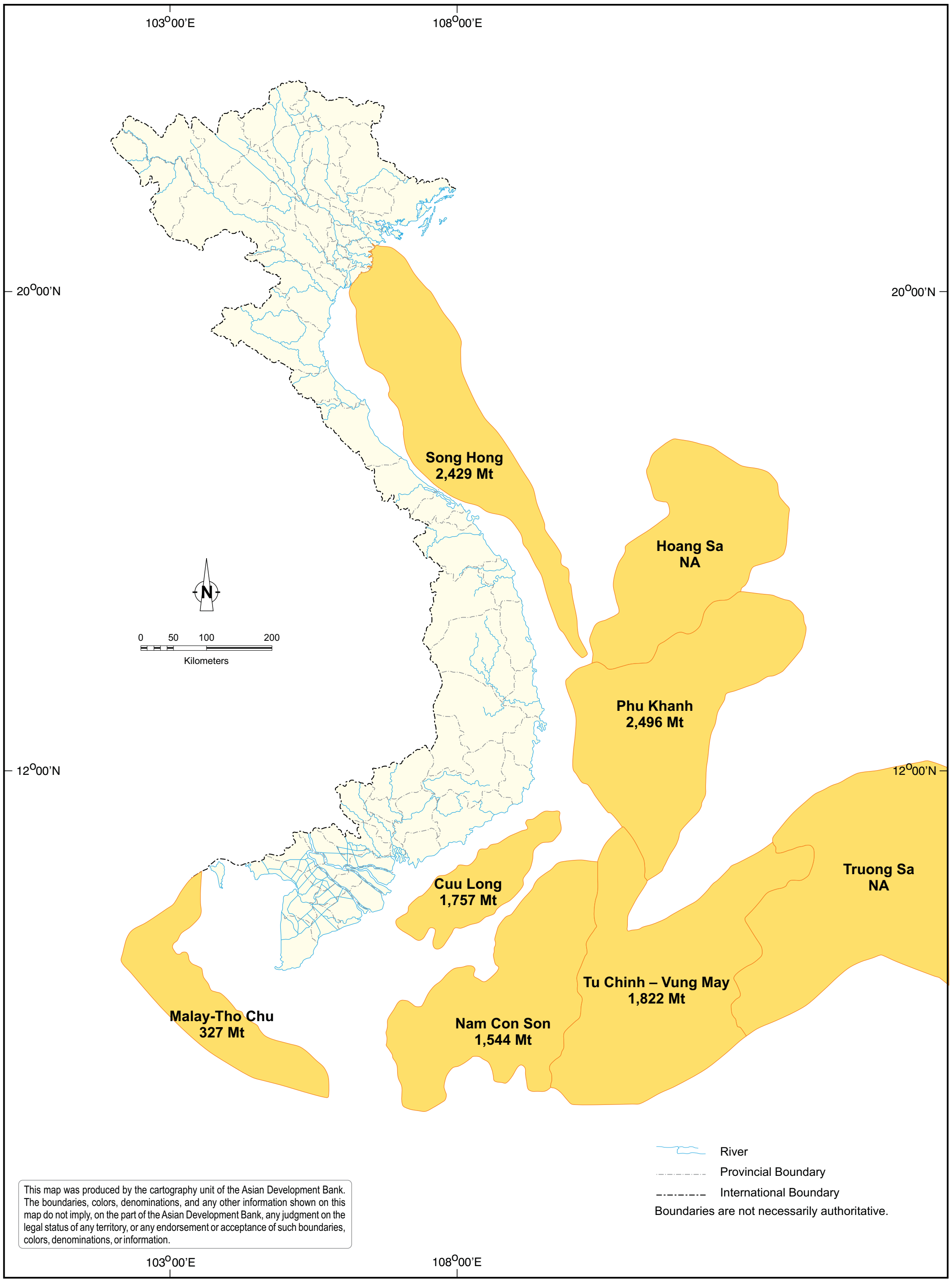
Source: Geoscience Foundation Incorporated.

Figure 4.5 **Sedimentary Basins of Thailand**



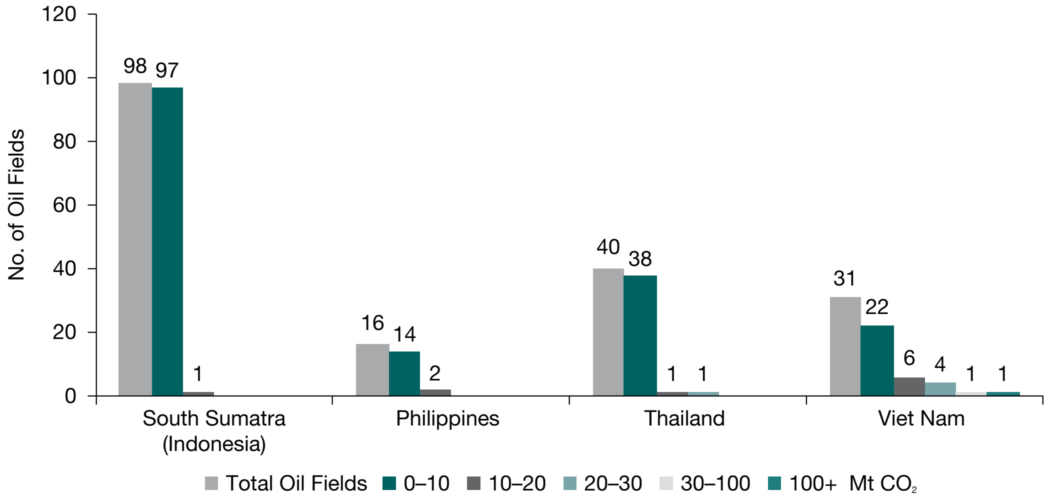
Source: Modified from Department of Mineral Fuels, Ministry of Energy.

Figure 4.6 **Sedimentary Basins of Viet Nam**



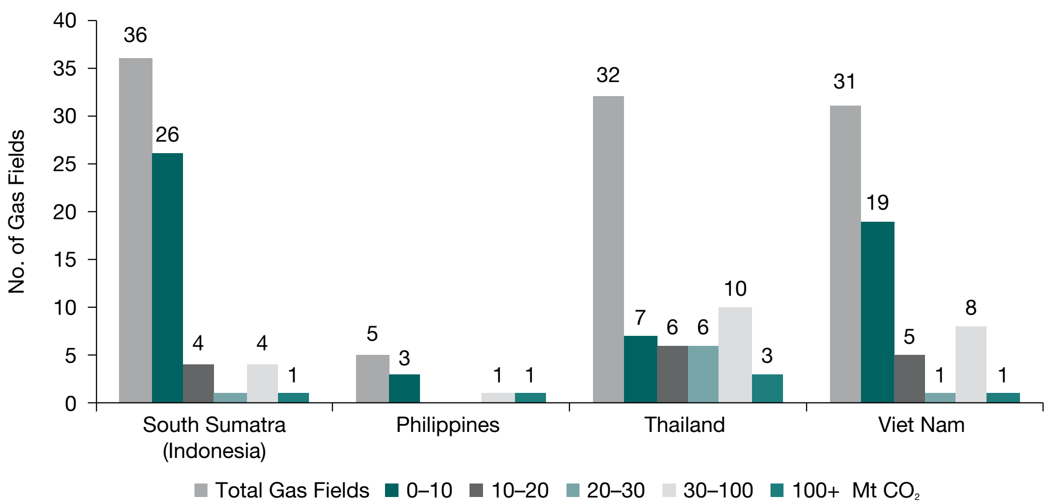
Source: Viet Nam Petroleum Institute.

Figure 4.7 **Distribution of Oil Fields by CO_2 Storage Volume**



CO_2 = carbon dioxide.

Figure 4.8 **Distribution of Gas Fields by CO_2 Storage Volume**



CO_2 = carbon dioxide.

sufficient data for evaluation. For one of the over 60 basins in Indonesia, only 59% of the oil and 47% of the gas resources in the South Sumatra Basin were available for evaluation. Consequently, the storage capacity in depleted oil and gas reservoirs identified for these countries represent a conservative minimum estimate.

4.3 Ranking of Storage Options in Oil and Gas Fields

After the quantification of the initial storage assessment, the study conducted a more detailed review of the identified options with the aim of ranking potential sinks by their suitability of storage. Only storage capacity in oil and gas fields was selected for this ranking process. Storage capacity in oil and gas fields is the best understood because of the data that was available for assessing the resource. In addition, CO_2 storage in oil fields provides an additional opportunity for EOR, which is likely to be favored as an initial target for CO_2 storage.

A two-staged ranking process involving qualifying and preferential criteria was used, as illustrated in Table 4.1.

As illustrated in Table 4.1, the fields that have been judged to meet the qualifying criteria are quantitatively ranked using the preferential criteria. These criteria are technical and economic attributes deemed to be important to storage. The maximum attainable score in each criterion reflects the importance of that criterion relative to the other criteria. For each field, the sum of scores across the criteria represents the final score for storage suitability (maximum attainable score of 100, with additional bonus of 5). The total score for each field establishes the ranking of storage suitability among the fields.

The qualifying methodology was adjusted slightly to account for small fields, which might not make the qualifying cut on their own but offer good storage opportunities as satellite fields or among a cluster of fields in close proximity to each other.

Results of the ranking score are illustrated in Figure 4.9.

The majority, just over half, of all the ranked potential CO_2 storage sites in oil and gas fields were judged to be of good suitability, with ranking scores of between 50 and 75. Oil and gas fields located in Viet Nam and Thailand were estimated to offer the highest suitability for CO_2 storage, with ranking scores between 75 and 100.

Wherever required, the names of the specific oil and gas fields have been withheld in this regional report to protect the confidentiality of the underlying data that were used for the analysis.

In South Sumatra (Indonesia), three of the four highest-scoring fields, representing about 28 Mt

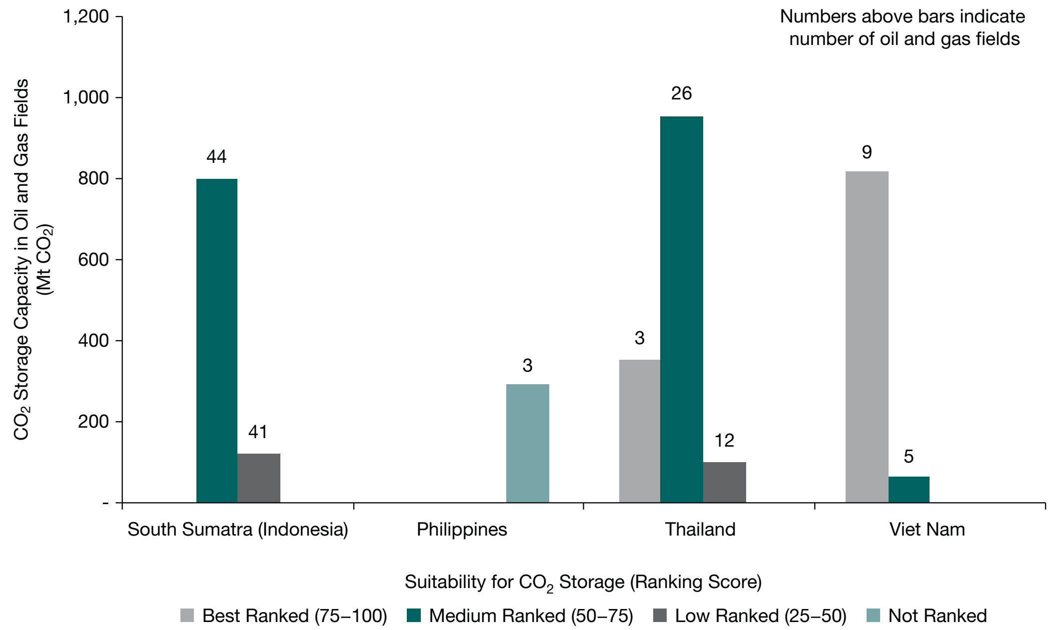
Table 4.1 **Ranking Criteria for Oil and Gas Fields**

Qualifying Criteria	
Capacity	Capacity > 10 Mt CO_2, with exceptions for satellite fields
Injectivity	Injection rate > 100 t of CO_2/day/well
Injectivity and Capacity	Reservoir > 3 m thick
Confinement: Depth	Depth to top of reservoir > 1,000 m
Confinement: Seal	Seal thickness > 3 m
Confinement: Faults	No active faults
Preferential Criteria	
Capacity	CO_2 storage (21)
Injectivity	CO_2 storage/day/well (10) Number of existing production/injection wells (10)
Confinement	Seal thickness (16) No. of abandoned wells (4) Contamination of other resources (4)
Economics	Cost recovery (enhanced oil recovery or other offset) (17) Existing infrastructure (4) Monitoring opportunity (4) Availability (depletion date) (5), plus a bonus of 5 if both oil and gas reservoirs are in single field Willingness of operator (5)

m = meter, Mt = megaton, t = ton.

Note: Number within parenthesis indicates the maximum attainable score in each criterion.

Figure 4.9 **Oil and Gas Fields Ranked by Suitability for Storage**



Note: In the Philippines, only three sinks made the initial cut for the ranking process. Given the limited number of storage sites, these sites were not subsequently ranked for suitability of CO_2 storage as carried out for the other three countries.

CO_2, are oil fields. The high ranking is due to their potential for incremental oil production from EOR. The highest-ranked field also scored highly because of its willingness to engage in CCS; the operator of the field was already planning to apply for an EOR permit. A gas field with an estimated storage capacity of 488 Mt CO_2 was ranked third. All of the fields are onshore.

In Viet Nam, the best storage sites also offer EOR potential. The top three ranked fields all offer opportunities for incremental oil production. These fields are also producing gas. The largest single volume site has an estimated storage capacity of 357 Mt CO_2 with 200 production wells and could be immediately available for EOR. All of the fields are offshore.

Thailand's top three oil and gas fields best suited for CO_2 storage could store as much as 350 Mt CO_2. Two of these three fields are primarily producing gas. Oil is being produced from the fields ranked second and third, with the oil legs offering 25 Mt and 16 Mt of storage, respectively. One field is onshore and the other is offshore. The highest-ranked storage site is also Thailand's largest single volume storage option in an oil and gas field. The site is estimated to be able to hold 240 Mt CO_2, achieving a total storage suitability score of 83 out of 100. This site could become available for storage by 2017.

In the Philippines, only three fields met the qualifying criteria and are located offshore. A detailed ranking of these three fields was not as exhaustively conducted due to lack of data, although a large oil and gas field with a potential storage capacity of 251 Mt CO_2 clearly emerged early as the best site. However, with active production, this leading storage option will not be available for storage until around 2030, another 2 decades from now.

5 Source–Sink Matching

The development of carbon capture and storage (CCS) in Southeast Asia will occur in phases. This will allow additional operational information about potential storage sites, capture sources, and transport links to be generated, which in turn will help to build confidence in the ability to create and sustain commercial-scale CCS projects. Source–sink matching is an essential part of the early planning process. It is designed not only to identify possible combinations of sources for carbon dioxide (CO_2) capture, transport links, and storage sites (sinks) for the pilot and demonstration projects, but also to be used to provide the basis for eventual commercial applications.

A commercial project follows a pilot and demonstration project. However, the pilot project should be selected with the intent of learning more about the commercial opportunity that could ultimately be the basis for the commercial project. The objective of the pilot is to provide information about capture, transport, and storage sink, which can subsequently facilitate the development of commercial applications. The source–sink matching, therefore, should anticipate the needs and benefits of a future commercial-scale project, on the basis of which a pilot should then be subsequently selected.

5.1 Matching Methodology

Potential sources and sinks were assessed in the preceding Chapters 3 and 4. These sources and sinks were scored and ranked for their suitability for capture or storage, though without considering the corresponding source or sink. The methodology for identifying prospective source–sink combinations began with the ranked list of sources and sinks. The methodology to be layered on that list includes additional parameters that are important for identifying suitable source–sink combinations. These parameters included consideration of CO_2 volume, transportation, scaling, CO_2 quality, and storage type.

Volume: The initial pilot for a potential commercial operation should focus either on the capture or storage site. Due to timing and cost, in most cases, the pilot should be designed around the potential commercial storage site. For this study, the CO_2 source was chosen based on storage piloting needs of 50–100 t/day (18,000–37,000 t/yr). In most cases, supply may not be from the potential commercial capture site. If the pilot is successful, a potential commercial capture source able to supply at least 500–2,700 t/day (183,000 t/yr–1 Mt/yr) will have to be developed for the demonstration project. The pilot storage site can then be subsequently developed into a commercial storage project able to absorb 2,700–30,000 t/day (1–11 Mt/yr).

The CO_2 volumes discussed may have to be reconsidered if opportunities for enhanced oil recovery (EOR) are identified. Commercial CO_2-EOR projects can be smaller, even as low as 300 t/day. In such cases, a smaller source gas–processing plant could be adequate for a commercial CO_2-EOR project. If this is transformed into a storage project as the EOR project winds down, this small-scale storage project could be considered commercial. Consequently, there could be two scales of commercial projects: projects that involve less than 2,700 t of CO_2 per day but are based on commercial CO_2-EOR; and projects that are greater than 2,700 t of CO_2 per day designed for depleted gas reservoirs, saline aquifers, and some larger EOR projects.

Transport: For a pilot that typically involves 50–100 metric tons of CO_2 per day, CO_2 transport could be carried out by truck or boat if a pipeline is not readily available. Building a pipeline may not be justifiable for such small volumes and the shorter duration of the pilot project's operation. However, a pipeline for transporting the CO_2 will eventually be required once, following the pilot, the demonstration or commercial project gets under way.

Scaling: To minimize uncertainty, it will be preferable to avoid matching a capture pilot to a storage pilot. Technical delays may occur when piloting new capture technologies and the size of the source may be inappropriate, making the flow of CO_2 uncertain and potentially stranding the storage pilot. To avoid this, the least expensive and reliable CO_2 source should be selected for the storage pilot. Although it will always be desirable to minimize the distance between source and sink, distance is not the presiding criteria. If deemed necessary, the commercial CO_2 capture source would be piloted separately.

CO_2 Quality: For pilots, the capture source ideally offers a pure stream of CO_2 free of other contaminants. This not only helps to minimize the cost of capture during the pilot project, but also allows the pilot to focus on the storage components rather than on capture.

Storage Type: Though saline aquifers and nonconventional storage options are all potential sinks, their estimates and characteristics are significantly more uncertain than oil and gas fields. In addition, storage costs in saline aquifers and nonconventional storage options will be higher because of the lack of infrastructure and also the lack of potential for any cost recovery similar to EOR. Ideally, large depleted oil and gas reservoirs where future storage costs can be offset by increasing oil and gas production from EOR and EGR represent the best initial prospects. However, the location of a storage pilot will need to have a large assessed storage capacity because it will need to have direct relevance to larger-scale commercial operations. The learning from a storage pilot is not readily transferable from one field to another because geological characteristics may differ across the reservoirs. Consequently, the most favored storage pilot will be in oil or gas reservoirs that have commercial storage possibilities but with an inexpensive CO_2 source available.

The process for deriving the source–sink combination was relatively subjective. It first plotted the ranked sink and sources in a map. Distance circles (100–300 km) were then drawn around the sources. The selection process was then conducted in consideration of the parameters identified above and through extensive discussions with assessment teams in each country. The identified combinations reflect not only the influences of the parameters above but also several nuanced localized considerations on the practicability, feasibility, and broad-based support for the specific sites.

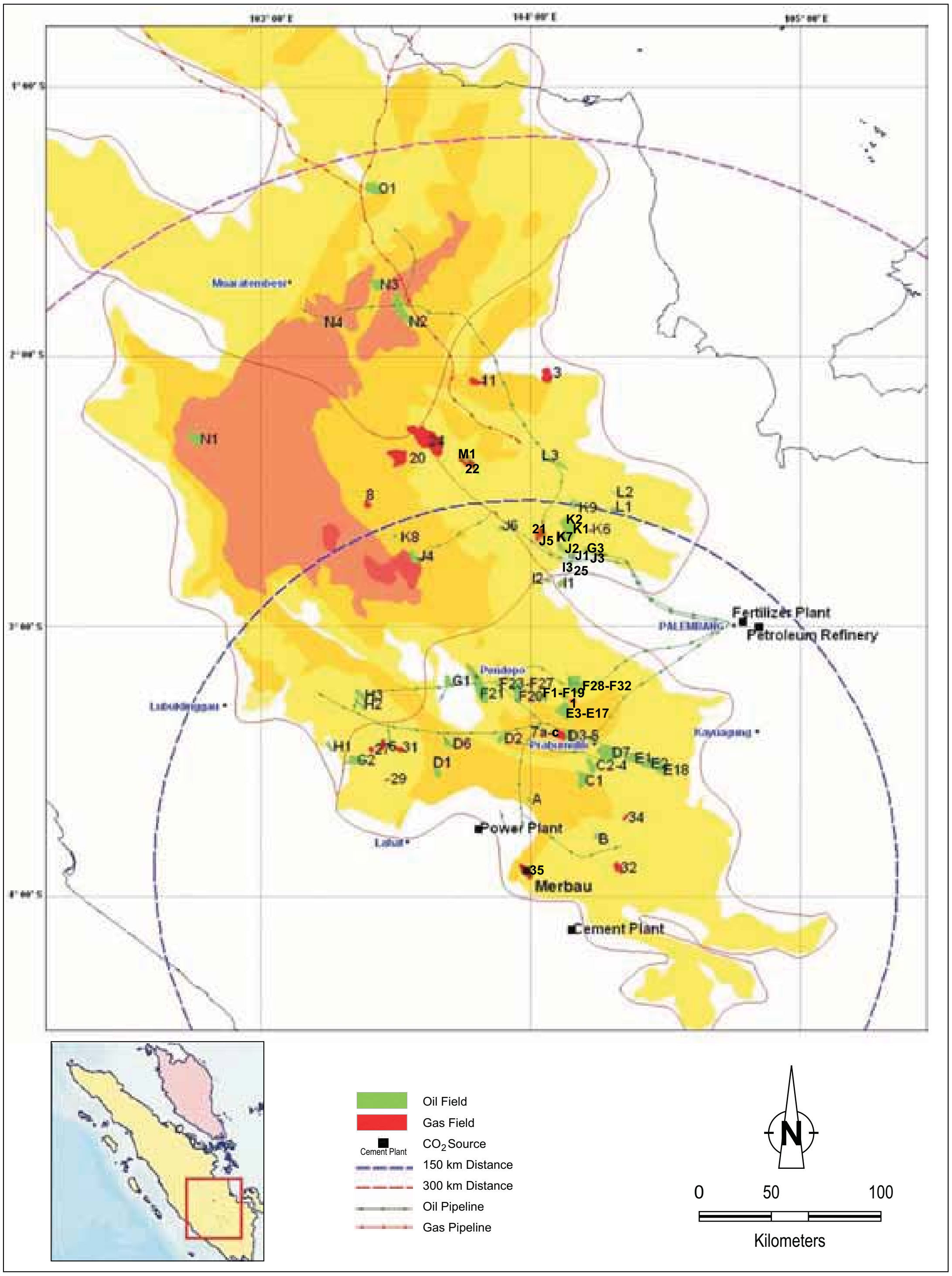
5.2 Indonesia (South Sumatra): Source–Sink Combinations

The results for the source–sink matching for South Sumatra must be read in consideration of data limitation that affected the analysis. Many of the gas-processing plants are located in the central and northern parts of the South Sumatra Basin. Some of these sources, which could have much larger volume, pure CO_2 streams, could be good potential candidates for capture. This capture potential and its potential impact on the most promising source–sink combinations were not evaluated at this time because of data limitations. However, these sources should not be neglected in future evaluations. These sources, along with the sources that were evaluated and sink sites, are illustrated in Figure 5.1.

All of the sources evaluated lie in the southern part of the basin within 150 km of each other. A natural gas–processing plant (0.15 Mt CO_2) was ranked first among the potential sources for which data existed. Regarding suitability for CO_2 capture, a natural gas–processing plant was followed by a coal-fired power plant, a fertilizer plant, a cement plant, and a refinery, in that order. The fertilizer plant currently produces streams of pure CO_2, but it is consumed entirely within the plant in the manufacture of fertilizer. However, since the plant may switch from natural gas to coal for the input fuel, excess CO_2 may become available in future for capture. In addition, the fertilizer plant is located very close to the refinery and the waste CO_2 streams from the two facilities could be integrated for storage.

The top-ranked gas-processing plant discussed earlier is an attractive CO_2 source. It can supply 0.15 Mt CO_2 per year, enough for commercial EOR operations and for a pilot CO_2 storage project. However, on its own, it will not be able to supply the CO_2 required for a commercial storage operation (commercial EOR operations can be done with smaller volumes). To rectify this, it will become necessary to identify some other source of primary CO_2 if the project is to be scaled up to a commercial storage operation. Fortunately, the other sources (as identified earlier)

Figure 5.1 **Source–Sink Matching for Oil and Gas Fields in South Sumatra**



Source: LEMIGAS.

are within 150 km of the gas-processing facility. A number of gas-processing plants, which were not evaluated, lie in the central and northern parts of the basin.

The 20 most attractive sinks are oil fields that have CO_2-EOR potential or gas fields with large storage potential. All of the large gas fields with storage capacities individually exceeding 40 Mt CO_2, barring one gas field, also lie between 150–200 km north of the gas-processing plant in the central part of South Sumatra. These highly prospective storage sites are within 50 km of other gas-processing plants, reconfirming the earlier point that some of the gas-processing plants that were not evaluated in this study because of data limitations should still be evaluated in the future. The most attractive oil fields are 70–100 km from the gas-processing plant and a similar distance from other gas-processing plants in the central part of the South Sumatra Basin.

For South Sumatra, the analysis of this study does not indicate one unambiguous choice for a commercial CO_2 source. Consequently, the recommendation for the best source is based on the individual source rankings. In this way, the coal-fired power plant emerges as the best CO_2 source for the oil reservoirs located in the south and central parts of the South Sumatra Basin. In addition, some of the large gas-processing plants in the central South Sumatra Basin could serve as a good commercial-scale CO_2 source for the large storage capacity in the gas fields.

The most attractive storage pilot in the South Sumatra Basin will be an oil reservoir where the commercial opportunity for CO_2-EOR exists and which could subsequently transition to storage. The four top-ranked fields emerge as the best prospects for a pilot. Three of these sites offer small storage capacity with sufficient commercial scale capture, good injectivity and ample opportunities for EOR. The fourth is a nearby gas reservoir offering a storage capacity of 40 Mt CO_2. The selection of the specific field from this leading list of candidate fields will depend on additional resolution of data on injectivity, EOR potential, and the willingness of the field owners to undertake CCS.

In the absence of CO_2-EOR (if only storage is considered), the gas reservoirs scored higher than the oil reservoirs. Four of the five largest gas reservoirs, each with storage capacity in excess of 40 Mt CO_2, are located in the central part of the South Sumatra Basin within 150 km of the key emission sources. If these gas fields are to be piloted, the gas-processing plant discussed above could serve as the source and CO_2 could be trucked over the 100–200 km between the sink and source during the piloting phase. Alternatively, a gas field could be matched with an oil field, so that the gas field could be used to store the excess CO_2 and act as a buffer for the EOR project when the oil field cannot accept all the CO_2.

Matching Sources to Other Geological Storage Options

Indonesia has a large coal bed methane resource, particularly in South Sumatra. At this time, it is being actively piloted. Once commercial CBM production starts, it may provide CO_2 storage opportunities complementing the oil and gas storage opportunities in the South Sumatra Basin. Saline aquifer storage potential underlies both oil and gas and CBM fields of the South Sumatra Basin.

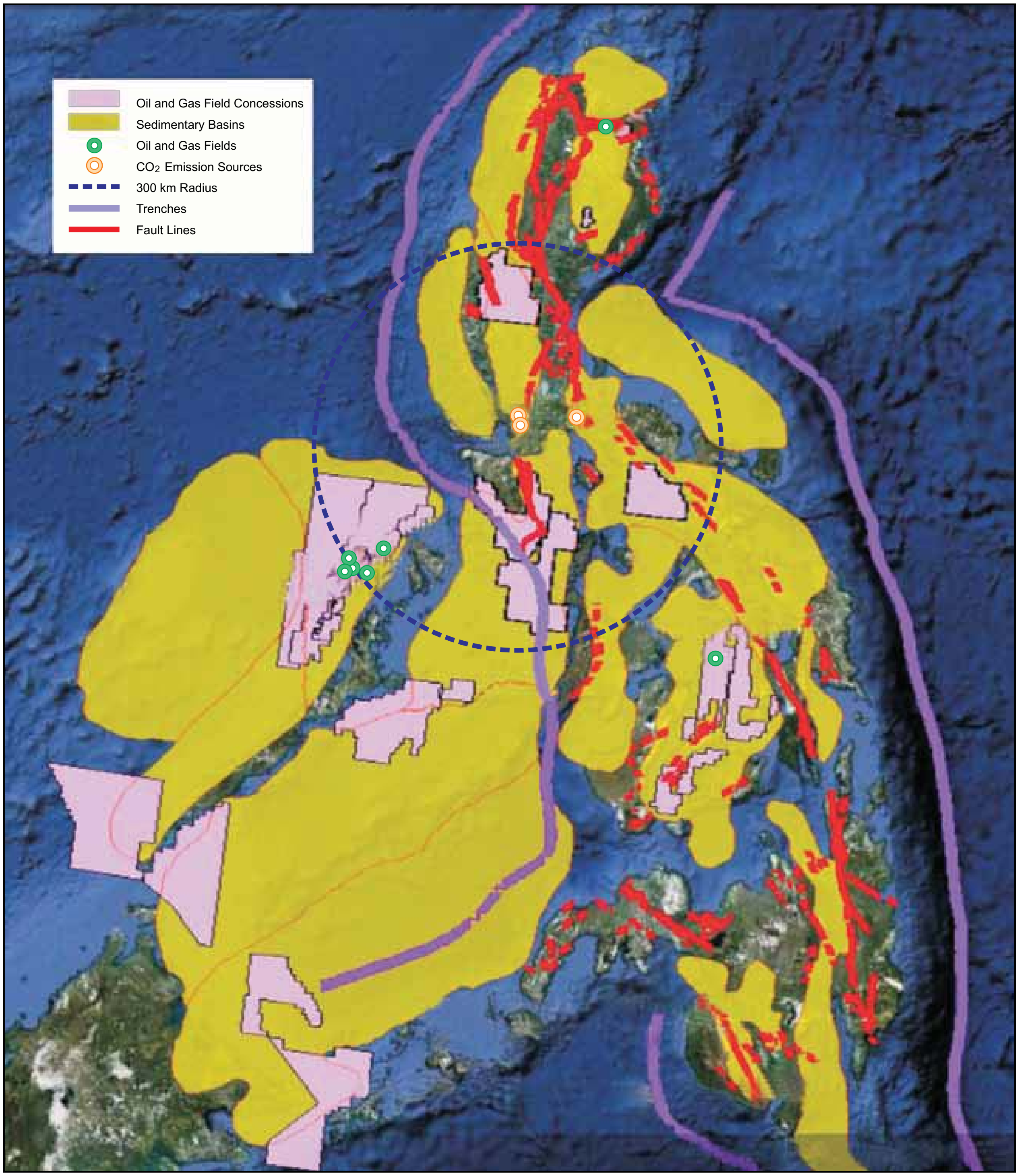
5.3 Philippines (CALABARZON): Source–Sink Combinations

The source–sink matching analysis for the Philippines evaluated storage options for saline aquifers, oil and gas fields, and others. Though the storage options in oil and gas fields emerged as the best option for a pilot and commercial-scale project, it is unlikely that they will be available within the next 20 years. Consequently, a more detailed discussion of other storage options also follows.

Matching Sources to Oil and Gas Fields

The best source–sink combination in the Philippines links the sources in CALBARZON with the storage potential in the currently producing offshore gas fields, as illustrated in Figure 5.2. Three natural gas power plants and one coal power plant were identified as viable candidates for capture. The total emissions from these sources are 10 Mt/yr. From this, the natural gas power plant with annual emissions of 3.3 Mt represents the best capture option. One gas field has the highest storage capacity at 251 Mt CO_2, sufficient to store the CO_2 from all four of the sources for at least 20 years, or the emissions from the largest NGCC power plant for at least 80 years.

Figure 5.2 **Top-Ranked CO_2 Sources and Sinks in the Philippines**



Source: Geoscience Foundation Incorporated.

Relative to other potential oil and gas sites, the offshore gas field is advantageous for several reasons. It is also located in the most geologically stable part of the Philippines. Other oil and gas fields also exist nearby. Having produced oil and gas before, physical characteristics, such as permeability and injectivity of the field, are well understood. It is already connected via pipeline to the gas power plant onshore.

The two critical challenges in using an offshore gas field may include timing and the distance to source. The gas field is located about a 300 km radius from the potential emission sources. If a new high-pressure pipeline dedicated to CO_2 transport must be built specifically for CCS, it would increase costs and make the project more expensive.

The availability of the existing 504 km natural gas pipeline for CO_2 transport is a key assumption that underlies the selection of this storage site as the "optimum" storage site. The premise is that a "reverse" flow would transport CO_2 from the emission sources to the gas fields. The study concluded that the current specifications of the pipeline could "technically" handle the estimated 10 Mt/yr CO_2 from CALABARZON. The analysis suggested that minimal engineering and capital outlay would be needed to receive and transport CO_2 from existing and future sources, though additional studies to define optimal use of the pipeline are still required.

There is some uncertainty about when the pipelines from the gas fields could become available for CO_2 transport. Even under a best-case scenario, it is unlikely to be before 2030. The oil and gas resources in the area are not expected to be depleted until 2030. The contractor for the field has indicated that if no other resources are developed in the vicinity, gas production from the fields will begin to decline by 2015 and be fully depleted by 2024, at which time it could become available for CO_2 transport.

Matching Sources to Saline Aquifers

There are six major CO_2 emission sources located near each other in the CALABARZON area, consisting of coal- and gas-fired power plants and a refinery. The gas-fired power plants receive their gas from offshore fields in Palawan via a 504 km subsea pipeline.

The two sedimentary basins evaluated in this study, Cagayan and Central Luzon, were estimated to have a storage capacity of 23 $GtCO_2$ in saline aquifers that could hold the total CO_2 emissions from CALABARZON for more than 100 years. The Central Luzon Basin was evaluated first for possible storage because it lies within 50 km of CALABARZON and is at lower risk of being affected by fault lines.

One key consideration in the selection of storage site is the high seismic activity in the Philippines. The earthquakes appear to be bounded by the two trenches on either side of the Philippines. CALABARZON is in a particularly active zone, while other potential sinks, such as the Northwest Palawan Basin, have very low seismic activity. Particular attention should be paid to the risk of storing CO_2 in a earthquake-prone zone such as the Central Luzon Basin. Based primarily on distance to the large sources and few other factors, but excluding risk of seismic activity, the Central Luzon Basin emerges as the best candidate for storage in saline aquifers. If seismic activity remains a concern, alternate options, such as the Northwest Palawan Basin, would be preferred.

Matching Sources to Other Geological Storage Options

Of the four countries investigated, the Philippines has the most limited opportunities for developing storage in its oil and gas fields over the next 20 years. Consequently, other possible nearer-term storage opportunities should be assessed. If investigated and developed adequately, geothermal, ophiolites, and coal seams could offer significant storage capacity in the Philippines. These storage options pose less of a long-term storage risk within the tectonically active Philippines. They may even offer distributed storage for many of the plants and emission sources located in the Visayas and Mindanao regions. The technical understanding of these geological storage options is currently very limited and significant pilot and field testing would be required before these sites emerge as real potential candidates.

In the Philippines, there are three *geothermal* areas within 150 km of CALABARZON that could warrant further consideration as potential storage sites:

(i) The Mount Natib geothermal prospect in Bataan is at an advanced exploratory stage. Exploratory work at the site has been under way since 1987. The low reservoir permeability, the existence of two geothermal wells, and the advanced stage of exploration makes this prospect a potential candidate for a pilot.

(ii) The Makiling–Banahaw geothermal field, located 70 km south of Manila in Laguna, is another potential opportunity. Having commenced commercial operation in 1979, it is a mature field and is the largest cumulative geothermal electricity producer over its lifetime. A pilot study on injection wells will need to be performed in the main injection area or on some of the idle wells should this site be considered for further analysis.

(iii) The Mabini geothermal prospect in Batangas has been explored since the 1980s. Though no wells have yet been drilled, the low temperature characteristic of this geothermal prospect is suitable for direct utilization, replacing water injection with CO_2 injection and/or utilizing a binary system technology for power generation. It could potentially use the CO_2 captured from emission sources in CALABARZON as the heat transfer fluid in the binary cycle system, thereby conserving the water or other chemical fluids traditionally used in the process.

In operating geothermal fields, the possibility of using CO_2 instead of water as the heat transfer medium to recover the geothermal energy should be investigated. Depleted or nonproductive geothermal fields can be used as CO_2 storage reservoirs by utilizing existing wells. The original geothermal reservoir pressure in depleted fields can be restored by injecting CO_2 before abandoning the field.

The Philippines also appears to have several opportunities for carbon storage in ophiolites. Since the CO_2 is captured as a carbonate mineral by reaction with the minerals of the ophiolite, it becomes inert and the CO_2 cannot be released by seismic events. Three ophiolite complexes lie within the 150 km radius of CALABARZON and seven more within 300 km. The most promising ophiolite is in Zambales, which is a large ophiolite complex just west of the Central Luzon Basin.

Activities designed to assess coal bed methane are also now under way in the Philippines in collaboration with the US Geological Survey under the project "Potential Coal Bed Methane and Related Coal Resources in the Philippines." However, these activities are currently focusing on Mindoro, Zamboanga del Sur, Cebu, Buug, and Zamboanga Sibugay and are all too far from CALABARZON to be identified as viable prospects.

5.4 Thailand: Source–Sink Combinations

Several of the key sources and sinks in Thailand are well aligned and offer achievable opportunities for CCS. The top ten individual storage sites range in capacity from 40 Mt to 245 Mt CO_2. The cumulative 20-year emissions from the top-ranked emission sources range from 20 Mt CO_2 to 360 Mt CO_2.

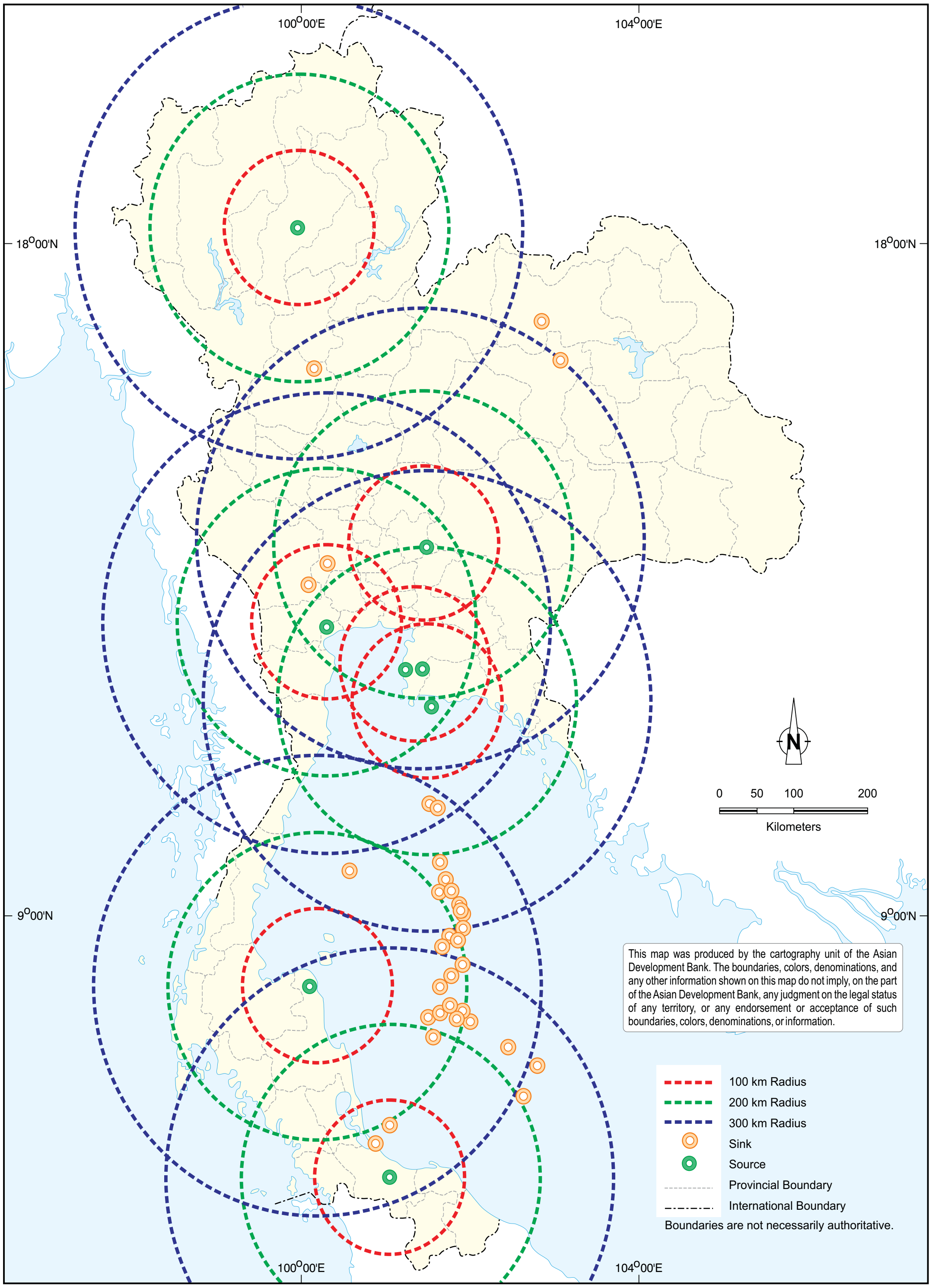
A plot of the sinks and the top ranked sources with 100 km, 200 km, and 300 km with circles indicating distances of 100 km, 200 km, and 300 km distance around the sources is illustrated in Figure 5.3.

Thailand offers a range of onshore and offshore possibilities, though offshore opportunities are more abundant. The coal-fired power plant complex in the north, the largest CO_2 source with 18 Mt CO_2 annually, is within 200 km of the number two ranked storage site and the top onshore storage site with a total estimated capacity of 49 Mt CO_2. This combination is also attractive with regard to EOR since approximately half of that storage capacity is related to oil reservoirs.

However, if all the CO_2 from this coal-fired power plant complex were captured and injected, it would fill the sink in 3 years. Individual units in the power plant complex vary in age, and the ability to capture of all the CO_2 is unlikely. A more realistic approach may be to use repowered units for CO_2 sources that will be associated with CCS. Other onshore possibilities include matching a gas-fired (NGCC) power plant (2 Mt CO_2 per year) with the adjacently located gas field (storage capacity of 22 Mt CO_2) and another gas field (storage capacity of 41 Mt CO_2), which are both within 100 km of the power plant.

There are many more offshore sinks in the Gulf of Thailand available to emission sources situated near the coast. The oil and gas fields in the Gulf of Thailand stretch in a southerly direction for 600 km. The southernmost emission source, a NGCC power plant (1.5 Mt CO_2 per year), has two small oil fields

Figure 5.3 **Key Sources and Sinks in Thailand**



Source: The Joint Graduate School of Energy and Environment.

nearby and is within 200 km of two gas fields with combined storage capacities of 260 Mt CO_2. About 300 km north of this southerly NGCC plant are a natural gas–processing plant (1 Mt CO_2 per year) and another NGCC power plant (2 Mt CO_2 per year). These two sources lie in a "sweet spot" with approximately 200 km separating them from the top ten offshore sinks in the Gulf of Thailand.

Another alternate set of attractive sources are a cluster of power plants near Bangkok (cumulatively about 23 Mt annually) along with a natural gas–processing plant (2 Mt annually). Although these sources are more than 200 km from potential offshore sites, the availability of pipelines connecting the fields to the natural gas–processing facilities could make it an attractive combination. In the longer term, the gas pipelines could be reversed to transport CO_2 from the sources to the offshore storage sites. The cluster of sources around Bangkok, along with the sources around Khanom, would be best placed for the commercial project, with the initial CO_2 coming from the natural gas–processing facilities.

Another potential source of CO_2 to be investigated are the offshore platforms where CO_2 is separated before the purified gas is sent to shore for further processing. While current results do not indicate large or long-lived CO_2 sources from offshore platforms, this situation could change dramatically as Thailand develops its oil and gas reserves.

The best demonstration project option, however, would be to use the oil reservoirs that offer an opportunity for EOR. An onshore field and an offshore field, with a cumulative storage capacity of 41 Mt CO_2, are the best options. With an inexpensive source of CO_2, these sites could serve as the demonstration project. If the offshore storage site is developed, numerous other nearby fields could be used to enhance the storage capacity if needed.

Matching Sources to Other Geological Storage Options

The sedimentary basins in Thailand that host the oil and gas accumulations contain saline aquifers that could host additional CO_2 storage. The 10 of the over 90 basins that have been evaluated show significant opportunities for storage in saline aquifers in the future after the depleted oil and gas fields have been fully utilized.

5.5 Viet Nam: Source–Sink Combinations

The top-ranked sources and sinks in Viet Nam appear evenly matched in size. The top ten ranked storage sites ranged in capacity from 23 Mt to 357 Mt of CO_2. Similarly, emission sources that will produce 2–5 Mt annually over 20 years resulted in cumulative production between 40–100 Mt of CO_2.

Opportunities for CCS in Viet Nam primarily lie in the southern part of the country. North Viet Nam offers few opportunities. The only oil and gas field within the 300 km radius of the top-ranked emission sources in North Viet Nam is too small, less than 2 Mt CO_2, to be considered for commercial scale. This eliminates the northern coal-fired power plant units from further consideration for use in depleted oil and gas fields.

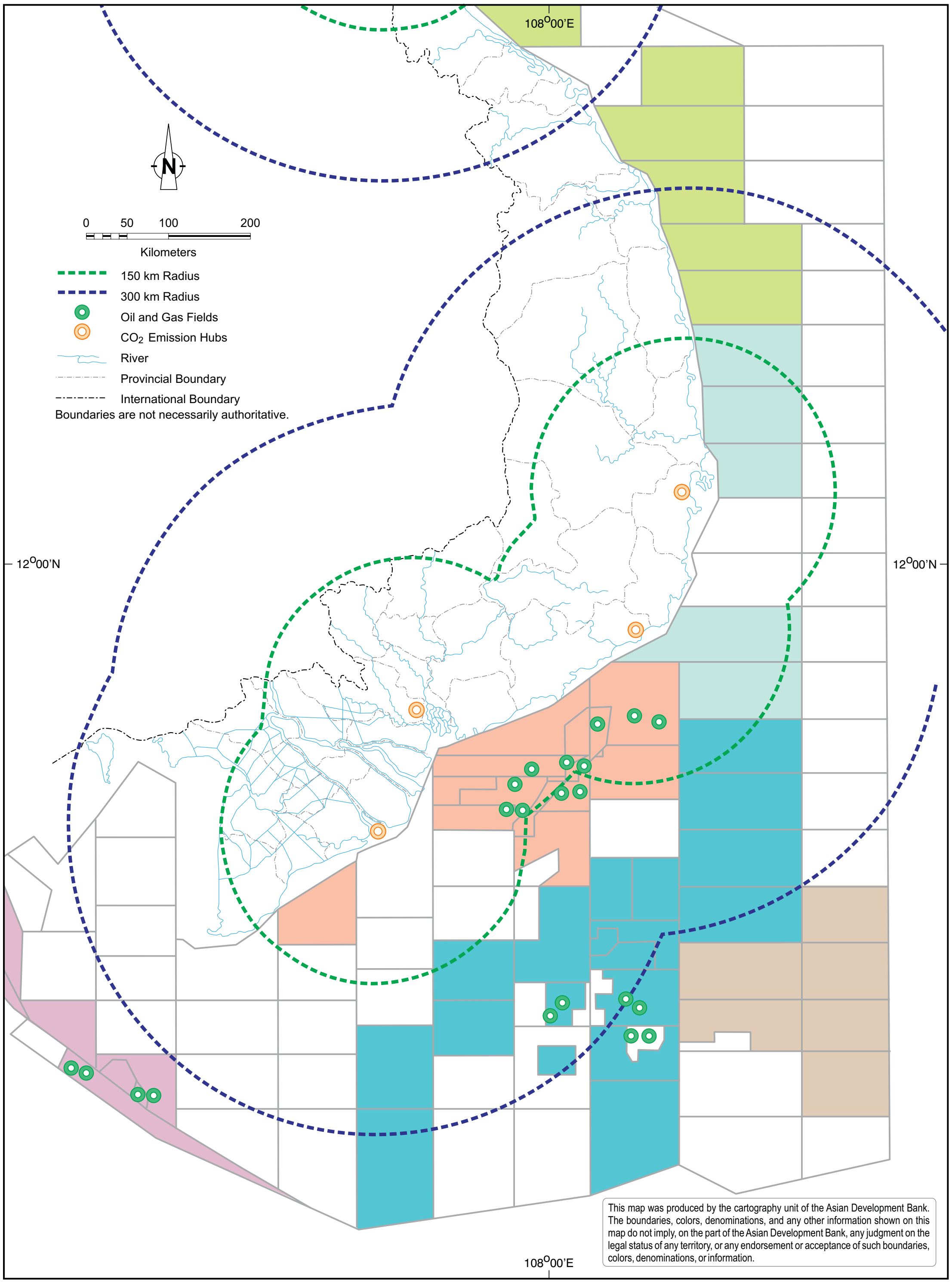
Other coal-fired power plants in North Viet Nam are poorer sources for CO_2 because of their age, reliability, and smaller capacities. This assessment of North Viet Nam may change in the future as the CBM industry develops to tap the theoretical CO_2 storage capacity of 458 Mt in CO_2-ECBM and as new power plants with better capture possibilities are developed.

South Viet Nam offers significant opportunities as illustrated in Figure 5.4. All of the emission sources in South Viet Nam lie within 300 km of a potential oil or gas field.

The most promising oil and gas fields lie in the Cuu Long Basin, which are within 150 km of all key CO_2 sources. The oil and gas fields in the Malay–Tho Chu Basin lie just outside the 300 km circle. The oil and gas fields in the Nam Con Son Basin lie partly within the 300 km circle.

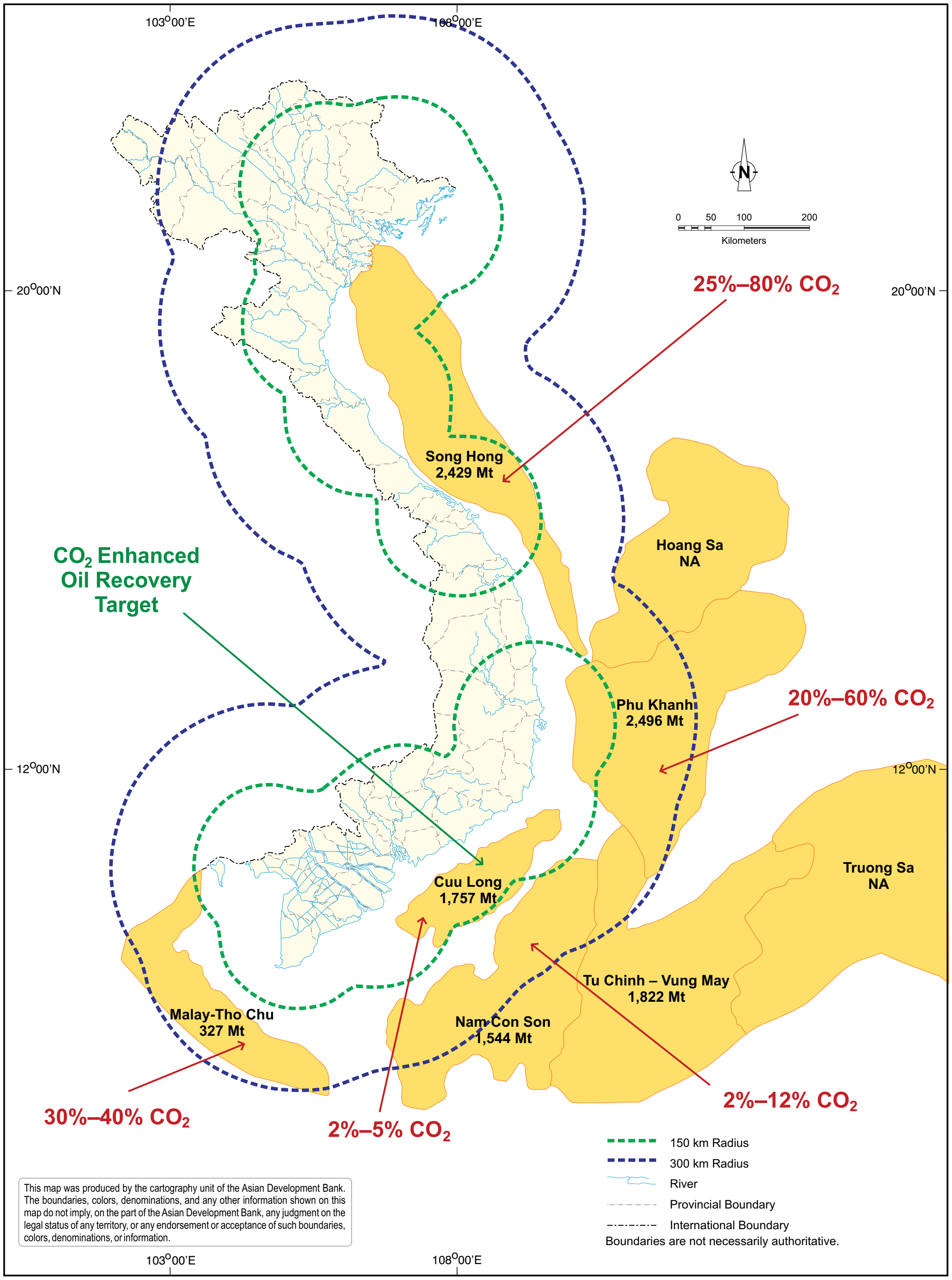
Most emission sources, excluding the two coal-fired power plants in the north, are all within 150 km of a sink in the Cuu Long Basin. These other units, comprising proposed subcritical and supercritical coal-fired power plants and the NGCC plant, are the closest prospective CO_2 commercial sources to the sinks. If needed, the CO_2 capacity of the NGCC power plant could be augmented by the nearby fertilizer plant. The fertilizer plant produces a pure CO_2 stream of 250 metric tons per day, for its internal use. Depending on the season, it may be possible to source CO_2 for pilot operations from this fertilizer plant.

Figure 5.4 **Top-Ranked CO_2 Sources and Sinks in South Viet Nam, 2012–2020**



Source: Institute of Energy.

Figure 5.5 **CO_2 Content in Natural Gas Fields in the Offshore Sedimentary Basins of Viet Nam**



Source: Viet Nam Petroleum Institute.

A cluster of eight offshore oil-bearing fields in the Cuu Long Basin appear the strongest prospects for storage. As EOR will remain a key focus, more precise ranking of the specific fields within the cluster will depend on more detailed information about the field depth and API gravity of the oil to determine the miscibility pressure for CO_2 flooding. Storage sites that have a pressure limit that supports CO_2 miscible flooding should be favored.

This analysis identified three emission hubs and one storage hub in South Viet Nam. The CO_2 emission hubs are the NGCC power plant, and the proposed supercritical and subcritical coal power plants. The CO_2 storage hub consists of the eight oil fields in the Cuu Long Basin. If the first commercial demonstration is a success, this will allow long-term planning for developing multiple CO_2 sources in South Viet Nam and multiple storage sites in the Cuu Long Basin, possibly justifying the construction of a CO_2 backbone pipeline in South Viet Nam.

Larger gas-processing sources of pure CO_2 may become available in the future. As illustrated in Figure 5.5, most of the natural gas produced in Viet Nam currently comes from the Cuu Long and Nam Con Son basins where the CO_2 content is low (generally less than 5%) and acid gas rejection to produce sales gas is currently not required.

As gas reserves are developed in other basins, much higher acid gas content, ranging from 20% to 80% CO_2, will be encountered. When commercial gas is produced from these basins and acid gas separation is required, large pure sources of CO_2 will become available from gas processing. This could offer large pure CO_2 sources and lower the supply cost of CO_2, and thus become the preferred option over power plants as emission sources for future CO_2-EOR projects.

Matching Sources to Other Geological Storage Options

Viet Nam has a large coal bed methane resource that is being actively piloted. Once commercial CBM production starts, it may provide CO_2 storage opportunities onshore that complement the oil and gas storage opportunities offshore. Saline aquifer storage potential underlies both oil and gas, and CBM fields.

5.6 Summary of Source–Sink Options for Pilot Project

The key source–sink options across the four countries are listed in Table 5.1 below.

Table 5.1 **Summary of Leading Source–Sink Match Options for Pilot Project**

CO_2 Source	CO_2 Storage	Distance	Advantages	Disadvantages
Indonesia				
Natural gas processing facility (Other gas processing plants in central and northern part of Sumatra not specifically evaluated for this study)	Oil fields onshore in the South Sumatra Basin If pure storage or larger capacities are desired, gas fields onshore in the South Sumatra Basin Saline aquifers and coal bed potential for storage	< 100 km (other gas processing are < 150 km)	Inexpensive small source of pure CO_2, though it might be enough for pilot or demonstration Onshore storage—eases cost and complexity compared to offshore Offers CO_2-EOR potential	Source may not provide enough CO_2 for commercial-scale development
Power plant followed by fertilizer		< 100 km	Larger and more consistent volume	Relatively expensive source of CO_2 capture Coal plant is not high efficiency, supercritical

continued on next page

Table 5.1 *continued*

CO_2 Source	CO_2 Storage	Distance	Advantages	Disadvantages
Philippines				
Three natural gas-fired power plants in CALABARZON	Offshore gas fields off Palawan Saline aquifers potential for storage	Approximately 300 km (or 500 km by existing subsea pipeline)	Distance between source–sink, but could be overcome because of existing pipeline if flow could be reversed and used for CO_2	Earliest gas fields will become available in 2024, realistically unlikely before 2030 Expensive capture and transport
Though speculative at this stage, there are potentially interesting opportunities for storage at geothermal fields and ophiolites with ample prospective CO_2 sources in the vicinity of those storage possibilities. These opportunities, however, need to be studied much more than the oil and gas fields before a better estimate of storage and capture potential can be estimated.				
Thailand				
Repowered units in the coal-fired power plant complex	Onshore oil and gas field Saline aquifers potential for storage	< 200 km	Entirely onshore (eases cost and complexity) Storage capacity enough to support 1–2 commercial projects Thailand's best EOR opportunity	Pilot CO_2 source may be distant Proposed coal-fired CO_2 sources lignite-based and subcritical—not ideal with high power loss for post-combustion CO_2 capture
CO_2 source gas-processing facilities; a second gas processing facility is also an option	Oil and gas field in the Gulf of Thailand Saline aquifers potential for storage	200+ km	Proximity to NGCC provides commercial-sized CO_2 source for longer term Other large CO_2 sources nearby Existing pipeline infrastructure EOR opportunity for one project Several depleted gas reservoirs could support multiple commercial CCS projects	By itself, gas-processing facility can only supply a small commercial-sized project Source–sink distance is large New subsea pipeline would be expensive if required
Viet Nam				
Natural gas combined-cycle power plant (Other two potential coal-fired power plant CO_2 sources, which were identified as potential capture sources, are low efficiency subcritical units)	Multiple offshore fields in Cuu Long Basin in South Viet Nam Most fields offer CO_2-EOR potential Saline aquifers and coal bed potential for storage	< 150 km	EOR has been studied previously (i.e., Rang Dong, White Tiger) Recent actual pilot CO_2 injection activities Likely a number of sources and sinks could be used Other very large non-EOR storage opportunities nearby	Pilot CO_2 source may be distant
Offshore CO_2 removal from prospective high-CO_2 fields (size unknown; assume 1 Mt/yr for demonstration)		< 100 km	Public interaction with the facilities would be minimized by the offshore location Source–sink pipeline will be short	CO_2 separation costs from natural gas are higher offshore due to equipment weight limitations Not currently within Viet Nam's petroleum development plans

CALABARZON = CAvite, LAguna, BAtangas, Rizal, and QueZON; CCS = carbon capture and storage; EOR = enhanced oil recovery; NGCC = natural gas combined-cycle.

6 Carbon Capture and Storage Cost Analysis

6.1 Introduction

This chapter discusses the incremental costs of implementing carbon capture and storage (CCS) in Southeast Asia and evaluates several financing options. The analysis employs standard analytical methods widely used in evaluating investment options in power and process plants and is structured in three segments: costs, sensitivities, and cost offset.

Cost: For power plants, the cost impacts are measured using the levelized cost of electricity (LCOE). The LCOE represents the all-in cost for electricity generation in dollars per megawatt-hour ($/MWh, or equivalent) and is the parameter best suited for the comparisons selected for this analysis.

The LCOE of power plants with CCS is compared against plants without CCS. Delta LCOE illustrates the incremental cost per unit of electricity relative to a reference plant (business as usual) without CCS. The analysis also compares the LCOE of power plants with CCS against the prevailing wholesale power prices, which offers a perspective on the potential impacts on electricity prices that consumers may face.

For natural gas–processing facilities, impacts are measured in terms of the incremental levelized costs in dollars per metric ton ($/t) of net carbon dioxide (CO_2) injected.

Sensitivities: The cost impacts reflect several underlying technical and economic assumptions. Sensitivities were conducted to evaluate the variations in costs resulting from changes in those underlying assumptions.

Cost Offset: The analysis contrasts cost against revenue options from enhanced oil recovery (EOR), along with subsidies or grants designed to defray incremental costs.

6.2 Assumptions

A comprehensive set of economic and technical analyses characterizing CCS for power and natural gas–processing plants was developed. The assumptions reflect the input of a wide range of experts, stakeholders, and insights from technical literature.

Financing assumptions were developed specifically for each country. As described in Table 6.1, these assumptions involve parameters associated with the cost of capital. These assumptions included the judgment that the financing parameters for introducing CCS in Southeast Asia would be different from conventional financing practices for other technologies, including a higher cost of capital due to the technical risk of CCS in a first-of-a-kind plant. As a result, the study team, for example, assumed that some low-cost concessional debt financing would be available.

For ease of exposition, the analysis is presented for a reference set of assumptions, though country-specific assumptions were slightly different. Country-specific analysis, as presented in the country reports and executive summary in Appendixes 1–4, uses assumptions specific to that country. A reference point is used here only for ease of exposition. For power plants, the Philippines was used as the reference point. For natural gas processing, Thailand was used as the reference. These reference points were selected merely because they approximated a midpoint in the range and do not represent an effort to develop generic assumptions that would be representative for all four countries.

Table 6.1 **Financial Assumptions** (%)

	Reference	Indonesia	Philippines	Thailand	Viet Nam
Owner's cost	23	23	23	23	23
AFUDC	9.0	10.4	9.0	8.4	10.4
Debt share	40	40	40	40	40
Debt cost (real)	4.5	8.0	4.5	3.0	8.0
Equity share	60	60	60	60	60
Equity cost	12	12	12	12	12
Income tax rate	30	25	30	30	25
WACC (real, after tax)	8.5	9.6	8.5	8.0	9.6

AFUDC = allowance for funds used during construction, WACC = weighted average cost of capital.

A comprehensive set of technical and engineering assumptions was also developed. It included assumptions for power plants with and without CCS, natural gas–processing facilities, transportation, storage, and fuel costs. For power plants, the study assessed a supercritical pulverized coal (SCPC) plant and a natural gas combined-cycle (NGCC) plant both with and without CCS. For natural gas processing, the study assumed that the CCS on these facilities would require only dehydration or compression along with transport and storage or the use of CO_2 in EOR. The assumptions were based on inputs from a wide range of technical experts, including country-specific national teams, and findings from relevant international technical literature.

The assumptions did not seek to represent partial CO_2 capture options, which may occur in a pilot or demonstration project. At the demonstration stage, partial CO_2 capture will cause the unit costs of CO_2 capture to be higher.

The base data for technical and engineering costs of power plants were taken from the NETL (2010b) report. The costs were updated to 2011 dollars using the US inflation rate. Pipeline and storage engineering cost data were derived from a report by Alstom (2011). Technical engineering cost estimates for compression and dehydration components of natural gas processing, along with the assumptions for EOR-related costs, were taken from NETL (2008). Unless otherwise noted, all dollars are in real 2011 dollars at a US location as a proxy to local engineering and labor costs.

The technical and engineering assumptions for power plants are described in Table 6.2.

When the economic assumptions are applied to technical-engineering costs, the resulting financing costs vary in countries. Rather than discuss all of the results for each of the countries, for ease of exposition, this regional report uses a reference point. The country-specific economic discussions are presented in country summaries in the appendix.

Accordingly, for the discussion on power plants, the Philippines is used as the reference point. This does not mean that the Philippines is used to characterize the costs of the region; rather, it is used as a reference point for the discussion merely because it fell approximately in the middle of the costs range. Similarly, for natural gas processing, Thailand is used as the reference point because this opportunity was not assessed for the Philippines, due to the latter's limited opportunities for natural gas production. Capital and operating costs vary by country, though this variation is relatively minor. The resulting country-specific capital and operating costs for power plants, along with the assumptions for natural gas–processing facilities and fuel prices, are presented in Table 6.3. Cost variations across the countries fall within the range of sensitivities that were considered.

Many of the technical and engineering assumptions were derived from technical literature that reported costs in US locations. The study did seek to localize costs by examining the potential cost differences

Table 6.2 **Reference Technical Assumptions for Power Plants**

	SCPC Power Plant		NGCC Power Plant	
	Without CCS	With CCS	Without CCS	With CCS
Gross capacity (MW)	580	663	570	570
Net capacity (MW)	550	546	560	482
Net generation (GWh)	4,095	4,066	4,170	3,589
CO_2 captured (Mt/yr)		4.2		1.4
CO_2 avoided (Mt/yr)		2.8		1.2
Power Plant Capital Costs ($/kW)				
Power plant and capture	2,846	5,113	1,055	2,137
CO_2 transport and storage costs		568		377
Incremental CCS capital costs ($/kW)		2,835		1,459
Power Plant Operating Costs ($/kW-yr)	**405**	**645**	**400**	**508**

CCS = carbon capture and storage, CO_2 = carbon dioxide, GWh = gigawatt-hour (1,000 MWh), kW = kilowatt, Mt = million metric ton, MW = megawatt, NGCC = natural gas combined-cycle, SCPC = supercritical pulverized coal, yr = year.

Table 6.3 **Power Plant, Natural Gas Processing, and Fuel Costs by Country**

	Reference	Indonesia	Philippines	Thailand	Viet Nam
Incremental capital cost for SCPC w/ CCS ($/kW)	2,835	2,845	2,835	2,806	2,902
Incremental capital cost for NGCC w/ CCS ($/kW)	1,459	1,464	1,459	1,444	1,493
CCS on Natural Gas Processing for 1 Mtpa					
Total capital cost (M$)	165	167	N/A	165	171
Annual operation cost (M$/yr)	14	12	N/A	14	11
Fuel Prices					
Coal prices ($/t)	120	70	120	120	100
Gas prices ($/GJ)	7.0	5.7	7.0	7.0	5.7

CCS = carbon capture and storage, M = million, NGCC = natural gas combined-cycle, Mtpa = million tons per year, SCPC = supercritical pulverized coal, yr = year.

between the United States and Southeast Asia. However, the study team judged that, in general, there was unlikely to be significant differences in overall costs, despite Southeast Asia having some lower labor costs.

For power plants, transportation and storage costs are not a large factor in overall CCS costs. Although distance between source and sink will vary by location, the study centered the transport costs assumptions using estimates for onshore pipelines 150 km long with a diameter of 18 inches for SCPC power plants, 14 inches for NGCC power plants, and 10 inches for natural gas processing—the latter to accommodate different flow rates of CO_2. These onshore pipeline costs were also used as a proxy for offshore installations on the basis that in three of the countries studied, offshore natural gas pipelines currently exist that could be refurbished at a lower cost to handle a reverse flow of CO_2 for an offshore demonstration or commercial CCS project. The costs assumed for storage wells in all cases assumed higher offshore costs reported in the published literature (Alstom 2011) for the installation of new infrastructure, even though in some cases existing wells could be adapted at a much lower cost. For this analysis, CO_2-EOR costs were based on onshore experience using information presented in the NETL 2008 report.

6.3 Results

6.3.1 Power Plants

As discussed earlier, costs for power plants are expressed in LCOE. A higher LCOE from CCS results chiefly from (i) higher capital and operating costs, (ii) higher fuel costs due to additional energy requirements for CCS, and (iii) CO_2 transport and storage costs. Figure 6.1 contrasts the LCOE for representative coal and gas power plants with and without CCS.

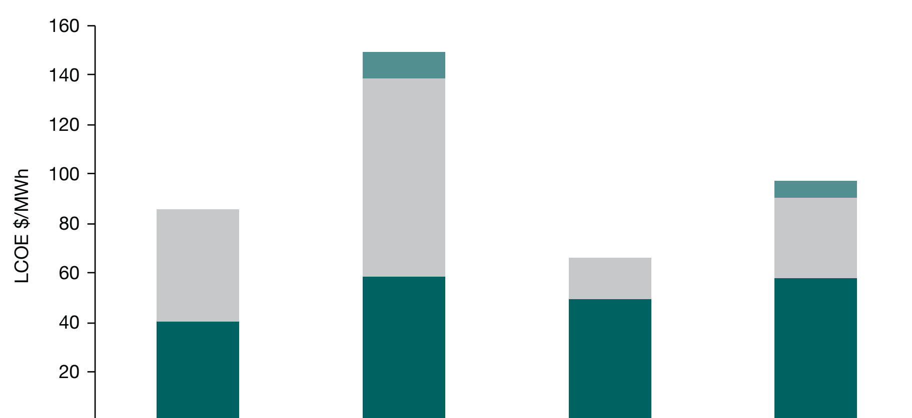
As illustrated in Figure 6.1, the LCOE of a SCPC plant with CCS increases 74% from $86/MWh to $150/MWh, against the equivalent plant without CCS. Similarly, relative to a NGCC plant without CCS, the LCOE of a NGCC plant with CCS increases approximately 50%, from $66/MWh to $97/MWh. As indicated earlier, these estimates report on the reference assumptions that are based on the Philippines. Across the four countries, the incremental LCOE relative to a plant without CCS varies between $57/MWh and $66/MWh for coal, and between $30/MWh and $32/MWh for gas.

Capital costs account for the dominant share of the LCOE in a SCPC plant, while fuel is the largest cost component in a NGCC plant. Nevertheless, in both cases, the increases in LCOE due to CCS are driven primarily by capital cost. With respect to LCOE from CCS, capital plus operations and maintenance (O&M) account for 55% of cost increase for a SCPC plant, and 52% of the cost increase for a NGCC plant. Almost all of that is from capital and very little is from O&M.

Incremental capital costs are the biggest driver of the increase in LCOE for CCS plants. A SCPC power plant with CCS faces a nearly 100% increase in capital costs relative to the reference plant without CCS, while CCS more than doubles the capital cost for a NGCC plant. Transport and storage are a relatively small part of the incremental costs. In terms of increase in LCOE, transport and storage account for approximately 17% of the increase in a SCPC plant with CCS, and 23% of the increase in a NGCC plant with CCS.

The loss in power plant efficiency, resulting from the need to use energy for CO_2 capture, accounts for almost a quarter of the incremental LCOE. In a SCPC

Figure 6.1 **Levelized Cost of Electricity of Power Plants with and without Carbon Capture and Storage**



	Supercritical Pulverized Coal		Natural Gas Combined-Cycle	
	w/o CCS	w/ CCS	w/o CCS	w/ CCS
Transport and Storage	–	11	–	7
Capital and O&M	45	81	16	32
Fuel	41	58	50	58

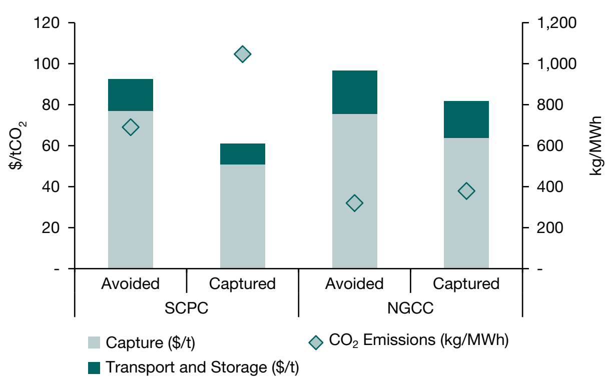
CCS = carbon capture and storage, LCOE = levelized cost of electricity, MWh = megawatt-hour, O&M = operations and maintenance.

power plant, efficiency drops by 31% when CCS is added to the power plant. Similarly, in a NGCC plant with CCS, the resulting efficiency loss is 14%.

The cost impacts of CCS are discussed as abatement costs in terms of the dollar cost per metric ton ($/t) of CO_2 captured or avoided, with the latter calculated relative to emissions anticipated from a "business-as-usual" reference plant without CCS. Such measures allow comparisons with other potential GHG options and help place a value on GHG reductions. Figure 6.2 illustrates the $/t$CO_2$ avoided and captured for coal and gas power plants with CCS, along with the CO_2 emissions captured and avoided per unit of generation.

Comparing the LCOE of CCS power plants against existing wholesale power prices is also an important indicator of the overall cost impacts. The wholesale power price represents the revenues that the generators receive for the electricity they sell.

Figure 6.2 **Abatement Costs for Carbon Capture and Storage in Power Plants**



CCS = carbon capture and storage, kg = kilogram, MWh = megawatt-hour, NGCC = natural gas combined-cycle, SCPC = supercritical pulverized coal, t = ton.

Note: Abatement costs for avoided emissions ($/t$CO_2$ avoided) denotes the cost of removing 1 ton of CO_2 not including any increase in emissions from incremental efficiency losses (or energy use) in CCS. Similarly, the avoided emissions rates (kg/MWh) denotes the amount of CO_2 per MWh of generation not including the emissions from incremental CCS efficiency losses. The abatement cost for emissions captured through CCS ($/t$CO_2$ captured) denotes the cost of removing 1 ton of CO_2 including the higher emissions from incremental efficiency losses of CCS. Similarly, the capture emissions rate (kg/MWh) denotes the amount of CO_2 per MWh of generation including the higher emissions from incremental efficiency losses of CCS.

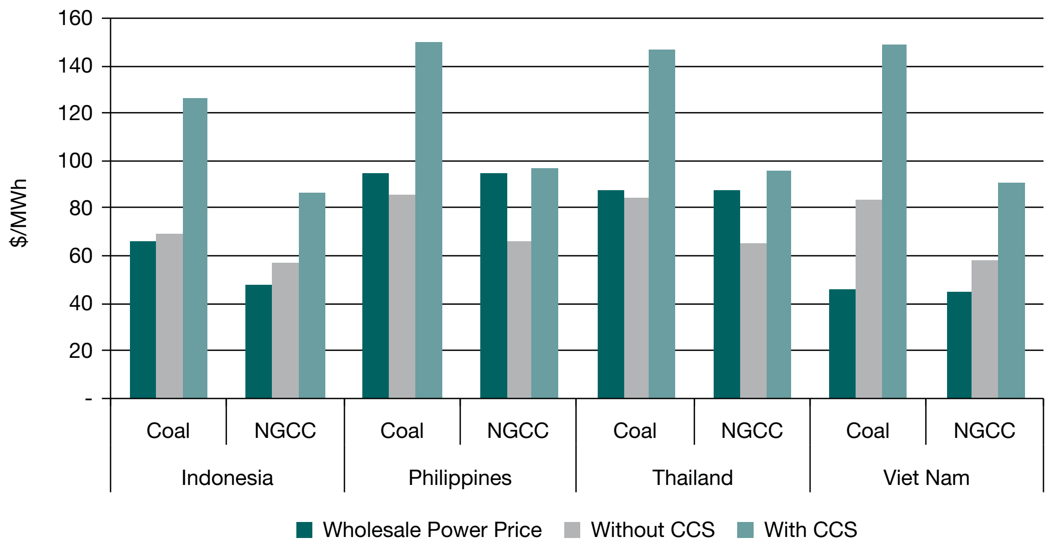
In the absence of any other financing mechanism, distribution utilities will need to shift the higher wholesale power price from CCS to their consumers to cover their increased costs. The comparison of LCOE against the prevailing wholesale power price provides an indication of the impact on power prices faced by consumers. The comparison is not an indicator of whether it provides power developers enough of an incentive to build power plants with CCS. In the absence of any mandated requirement for CCS, developers will not be motivated to build plants with CCS simply because the wholesale price is high enough to cover the LCOE of a CCS plant. Plant owners will compare the margins they receive from plants with and without CCS to make a determination of which plant to build. Consequently, plant owners may still need to be compensated for the loss in margin from the CCS plant, even if the power price is high enough to cover the LCOE of CCS.

Wholesale power prices vary across the four Southeast Asia countries. Indonesia and Viet Nam maintain separate wholesale power prices for coal and gas in a negotiated process with the government. The Philippines and Thailand have active electricity markets that provide power plants with one prevailing price for all generators. For Thailand, the average wholesale power price for 2008/2009 has been used for the comparison. The Philippines operates a mandatory pool market, which over the last few years has been characterized by high prices and significant volatility. Consequently, to avoid the influences of short-term variations that often reflect system constraints, this analysis used the long-run marginal cost of a coal plant as the benchmark price for the comparison in the Philippines.

Figure 6.3 contrasts the wholesale power prices (i.e., tariffs paid to generators) against the LCOE of coal and natural gas power plants with and without CCS.

Across the four countries, the LCOE for CCS coal plants is higher than prevailing wholesale prices by $58/MWh–$103/MWh. Similarly, the LCOE for NGCC plants is higher than prevailing wholesale prices by $2/MWh–$45/MWh. In the case of the Philippines and Thailand, the LCOE of a NGCC power plant with CCS is only marginally higher than the wholesale power price. In addition, in Viet Nam, the current wholesale power price is not high enough to cover the LCOE of new power plants. Consequently in

Figure 6.3 **Comparison of Wholesale Power Prices against Levelized Cost of Electricity of Power Plants with and without Carbon Capture and Storage**



MWh = megawatt-hour, NGCC = natural gas combined-cycle, SCPC = supercritical pulverized coal.

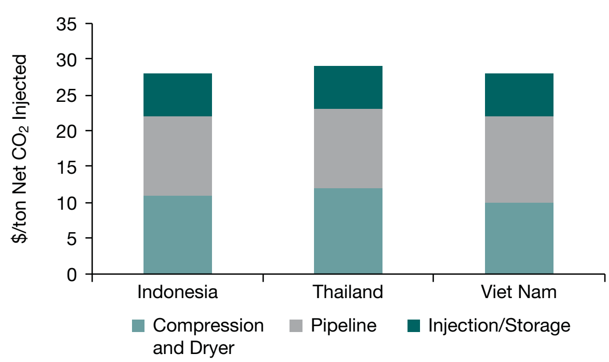
Viet Nam, the LCOE of new power plants relative to existing wholesale power price also includes the support needed to build any type of new power plant.

6.3.2 Natural Gas Processing

For natural gas processing with CCS, the levelized costs are reported per unit of net CO_2 injected. There is very little variation in the resulting levelized cost across the countries, as illustrated in Figure 6.4. The levelized cost is approximately $29/t net CO_2 injected without EOR. With EOR, the oil producer picks up the injection/storage costs, and the incremental levelized cost to the natural gas–processing facilities drops by $6/t net CO_2 injected.

Natural gas–processing facilities offer an exciting low-cost opportunity for CCS in Indonesia, Thailand, and Viet Nam. These facilities could provide the initial entry point for CCS by offering a steady stream of low-cost CO_2 with the added potential benefit of being exploited for EOR. Furthermore, new gas fields with high CO_2 content are likely to enter production in the future. This will require mandatory CO_2 removal to meet the sales gas specifications. Such CO_2 capture offers a steady flow of large volumes of pure CO_2 at low cost.

Figure 6.4 **Levelized Cost of Natural Gas–Processing Facility with Carbon Capture and Storage**



Note: Natural gas processing was not evaluated for the Philippines due to limited opportunity. Assumes availability of pure, vented CO_2 in the cost analysis for all countries.

6.4 Sensitivities

The results discussed reflect several economic, technical, and engineering assumptions that are inherently uncertain and could change significantly in the future. To capture this uncertainty, sensitivities were developed for key parameters to examine how the LCOE of the power plants might respond to changes in the underlying assumptions. Sensitivities were conducted by increasing and decreasing the following three parameters by 50%: (i) incremental capital costs for CCS, (ii) fuel prices, and (iii) interest rates. These sensitivities are not intended to suggest that all possibilities are equally probable. Rather, it is designed to indicate the influence that the three key parameters have on the results and to offer a reasonable bound for the uncertainty in the results.

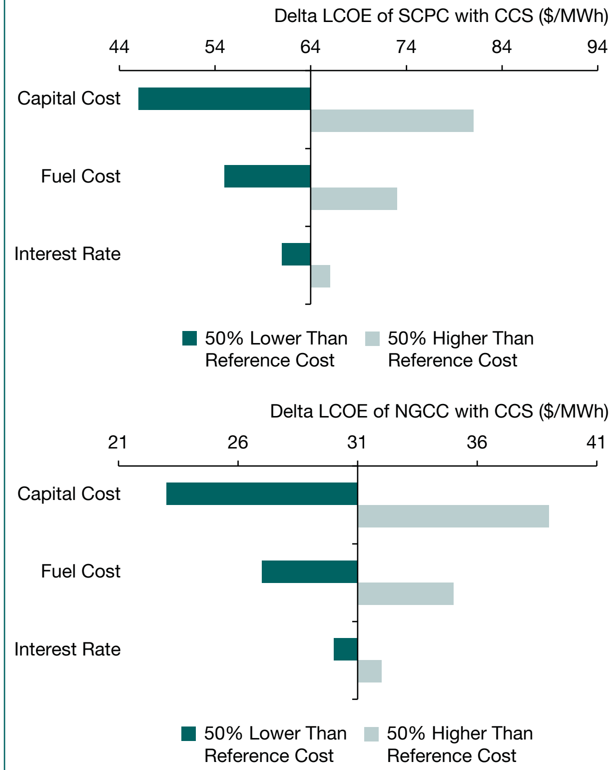
Figure 6.5 illustrates the range of results across the sensitivities for both SCPC and NGCC.

Variations in the incremental capital cost have the largest impact on the resulting LCOE. A 50% change in the incremental capital of coal CCS changes the delta LCOE by 26% relative to the reference delta LCOE. Similarly, in the case of NGCC, a 50% variation in the incremental capital cost changes the delta LCOE by 25% against the reference delta LCOE. The results suggest that gains from technological or other improvements that lower the incremental capital cost will have large impacts on the affordability of CCS. Programs that specifically target the incremental capital costs are likely to be most effective in making CCS more affordable.

Variations in fuel prices and interest rates have a more moderate impact on delta LCOE. A 50% change in coal price changes the delta LCOE of a coal plant with CCS by 15% against the reference delta LCOE. For the NGCC plants, a 50% change in gas price changes the delta LCOE of NGCC plants with CCS by 13% against the reference delta LCOE. This variation largely reflects the energy needed for CCS. Technological changes that enhance the energy efficiency of CCS will help to shrink that delta LCOE.

Changes in interest rate have very limited impact on the delta LCOE. Against the reference delta LCOE, a 50% variation in the interest rate changes the delta LCOE of SCPC plants with CCS by 5%, and of the NGCC plants with CCS by 3%. The study assumes that the plants with CCS and without CCS are leveraged at 40% and that the share of debt does not change with changes in interest rate. In reality, changes in interest rates could alter the debt–equity capital structure of a project. However, the study is not seeking to offer insight into the optimal capital structure for CCS plants. Rather, the insight from this sensitivity is intended to estimate the potential impact of changes in interest. The results clearly indicate that the impact of interest rate variation will be small, suggesting that financing programs seeking to provide grants to cover interest costs of CCS, or to provide concessional lending rates, will themselves have rather limited impact on reducing the delta LCOE of CCS.

Figure 6.5 **Sensitivity Results**



CCS = carbon capture and storage, LCOE = levelized cost of electricity, MWh = megawatt-hour, NGCC = natural gas combined-cycle, SCPC = supercritical pulverized coal.

Note: Delta LCOE represents differences between LCOE of a plant with and without CCS.

6.5 Financing

Several financing options are available to support the development of CCS. This analysis focused on the mix of revenues and grants that are typically discussed for CCS, in addition to programs that could potentially involve domestic and international funding. The objective of the analysis was to illustrate how much of the delta LCOE could be offset by a financing scheme. For power plants, the delta LCOE was contrasted against EOR revenues, targeted subsidies, and preferential (renewable style) tariffs. For natural gas processing, the financing analysis compared the incremental levelized cost of CCS only against revenues from EOR because the incremental cost was likely to be recovered from EOR revenues.

The cost evaluations and financing mechanisms for CCS have been conducted in the context of considerable uncertainty over an international climate regime. These costs, and proposed measures to finance these costs, could be significantly influenced by international climate agreements and even domestic regulations within the four countries.

Enhanced Oil Recovery: Where available, revenues earned through EOR are one of the best funding opportunities for CCS. The analysis reviews three scenarios for EOR: oil prices at $80/bbl, $100/bbl, and $120/bbl. With EOR, the oil producer shares with the CO_2 producer a certain portion of the gains from the incremental oil production after retaining production costs and a 40% pretax profit margin. The revenues from EOR are converted to $/MWh equivalent for power plants, and $/t net CO_2 injected for natural gas–processing facilities.

Targeted Subsidy: Three targeted subsidy programs are considered: a 50% waiver of the incremental capital cost, a 50% subsidy of fuel cost, and a 50% waiver of interest cost. The impact of the targeted subsidies is illustrated in terms of $/MWh. Each subsidy component can be evaluated in isolation or in combination with the other subsidies.

Preferential Tariff: These tariffs borrow from the feed-in tariff and other generation incentives available to renewable energy programs. Although the amount of renewable energy generation will be smaller than from CCS, the tariffs provide an indication of potential willingness for a preferential tariff. As a simple reference, the analysis uses the incentive for wind generation in Thailand.[10] In the analysis, the preferential tariff is presented as the difference between Thailand's tariff for wind and the LCOE of the reference plant without CCS.

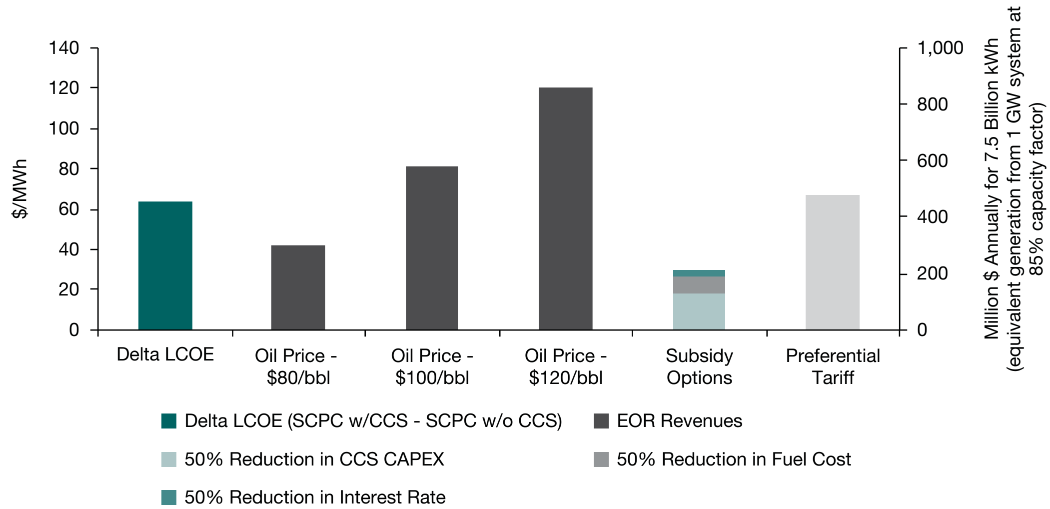
Figure 6.6 and Figure 6.7 illustrate the results of the financing analysis for power plants. In the illustrations, the primary (left, y, vertical) axis represents the delta LCOE and financing options in $/MWh, while the secondary (right, y, vertical) axis represents the delta costs and financing options in million dollars annually for equivalent generation of 1 GW system running at 85% capacity factor (7.5 billion kWh).

Without financing support, a SCPC power plant with CCS would incrementally cost $64/MWh. Revenues from EOR could offset those costs by $42/MWh with oil prices at $80/bbl. At oil prices above $100/bbl, the implied EOR revenues of $81/MWh would fully cover the incremental costs of CCS. Subsidies targeting CCS capital expenditures (CAPEX), fuel, or interest collectively offset up to $30/MWh. A preferential tariff of 40% of the Thailand wind tariff at $67/MWh could entirely cover the incremental cost of CCS. However, the total financing requirement at $500 million from the use of renewable-based tariffs (such as 40% of the Thailand wind tariff applied to equivalent generation from a 1 GW system) could be much higher for CCS than renewable energy because it would cover a larger volume of generation than is currently applicable for renewable energy.

As illustrated in Figure 6.7, a NGCC power plant with CCS will incrementally cost $31/MWh. Revenues from EOR could offset the costs by $15 to $44/MWh for oil prices ranging from $80/bbl to $120/bbl. At oil prices of approximately $100/bbl, the entire incremental cost of a NGCC plant with CCS could be recovered. Subsidies targeting CCS capital expenditures, fuel, or interest collectively offset up to $13/MWh. A preferential tariff of 20% of the Thailand wind tariff at $33/MWh could entirely cover the

[10] Incentives for wind vary across the four countries in Southeast Asia. In Thailand, the feed-in tariff for wind is $167/MWh and is used as the illustrative reference for this analysis. In Indonesia, the tariff for wind is $110/MWh and in Viet Nam $85/MWh. The Philippines recently approved a feed-in tariff for wind of $196/MWh, which will be effective for 2 years.

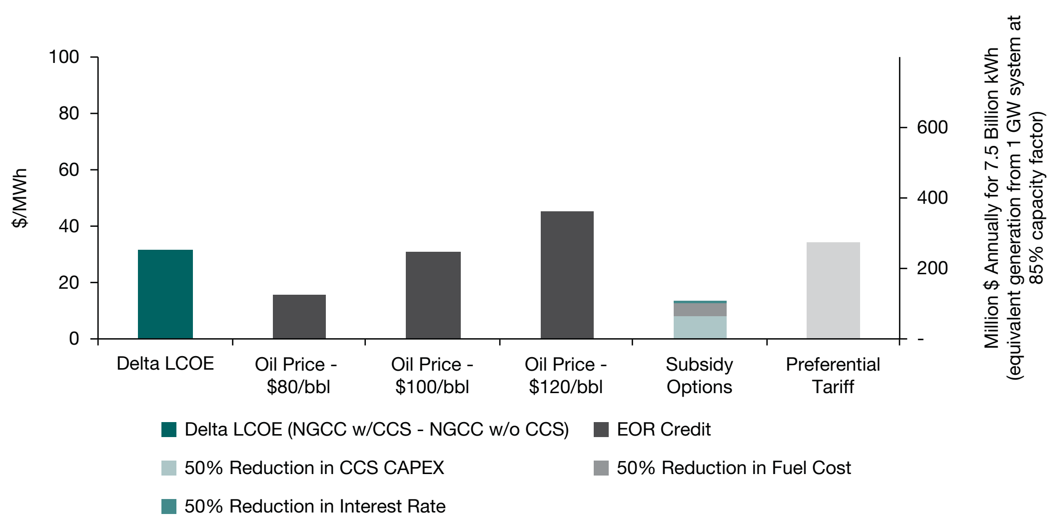
Figure 6.6 **Incremental Cost and Financing Options for Supercritical Pulverized Coal Power Plant with Carbon Capture and Storage**



bbl = barrel of oil, CAPEX = capital expenditures, CCS = carbon capture and storage, EOR = enhanced oil recovery, GW = gigawatt, kWh = kilowatt-hour, LCOE = levelized cost of electricity, MWh = megawatt-hour, SCPC = supercritical pulverized coal.

Notes: Delta LCOE represents differences between LCOE of a plant with and without CCS. The preferential tariff is illustratively based on the wind tariff from Thailand.

Figure 6.7 **Incremental Cost and Financing Options for Natural Gas Combined-Cycle Power Plant with Carbon Capture and Storage**



bbl = barrel of oil, CAPEX = capital expenditures, CCS = carbon capture and storage, EOR = enhanced oil recovery, GW = gigawatt, kWh = kilowatt-hour, LCOE = levelized cost of electricity, MWh = megawatt-hour, NGCC = natural gas combined-cycle.

Note: Delta LCOE represents differences between LCOE of a plant with and without CCS.

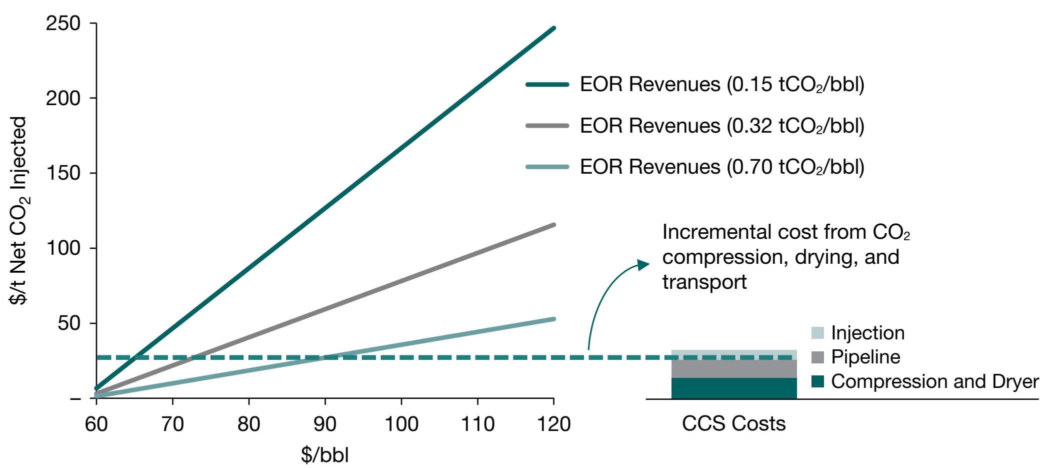
incremental cost of CCS. The financing requirement for this preferential subsidy at $250 million (applied to equivalent generation from a 1 GW system) would also be lower than that required for the equivalent coal plant with CCS.

The case of natural gas processing is different from that of power plants. Natural gas–processing plants with CO_2 separation already occurring as part of routine operations can produce a low-cost stream of CO_2 and are well suited for EOR because they are often also located close to oil and gas wells. The analysis evaluated financing for natural gas processing with CCS using only expected revenues from EOR, as illustrated in Figure 6.8. The analysis included three sensitivities on efficiency of incremental oil production from CO_2 in EOR.

Even under the lowest efficiency of oil production per metric ton of CO_2 (i.e., 0.7 tCO_2/bbl), the incremental costs of CCS in natural gas processing can be recovered at implied EOR with oil prices at $90/bbl. When injection/storage costs are not considered, that oil price could be lower. At higher productivity of oil production per metric ton of CO_2, oil prices as low as $65/bbl could entirely offset the incremental CCS cost.[11]

This analysis of EOR revenues from natural gas production is based on the assumption that oil producers will share the value creation of CO_2 with the CO_2 producer. This may not always be the case. An oil producer may instead choose to compensate the natural gas producer for the incremental cost rather than for the value creation. Also, the natural gas producer may want to have a steady CO_2 market, requiring the EOR operator to design the injection of the CO_2 so that a constant amount of purchase (net) CO_2 is utilized in the oil recovery scheme. The consideration will also be guided by various factors including the production-sharing arrangements, applicable tax regime, and ownership structure, as well as other parameters. The stylized illustration in this analysis clearly does not reflect many of these complexities and is intended rather to provide an indicative view of how EOR could serve as a source for financing CCS. With EOR revenues, suitably located and

Figure 6.8 **Incremental Cost and Financing for Natural Gas Processing with Carbon Capture and Storage**



bbl = barrel of oil, CCS = carbon capture and storage, EOR = enhanced oil recovery, t = ton.

11 EOR revenues were developed assuming oil production costs of $35/bbl and that the oil producer would retain a 40% pretax margin for every additional barrel of oil produced. The three EOR revenue scenarios vary the amount of CO_2 required for 1 bbl of oil to be produced.

sized natural gas–production facilities could serve as one of best entry points for CCS development in Southeast Asia.

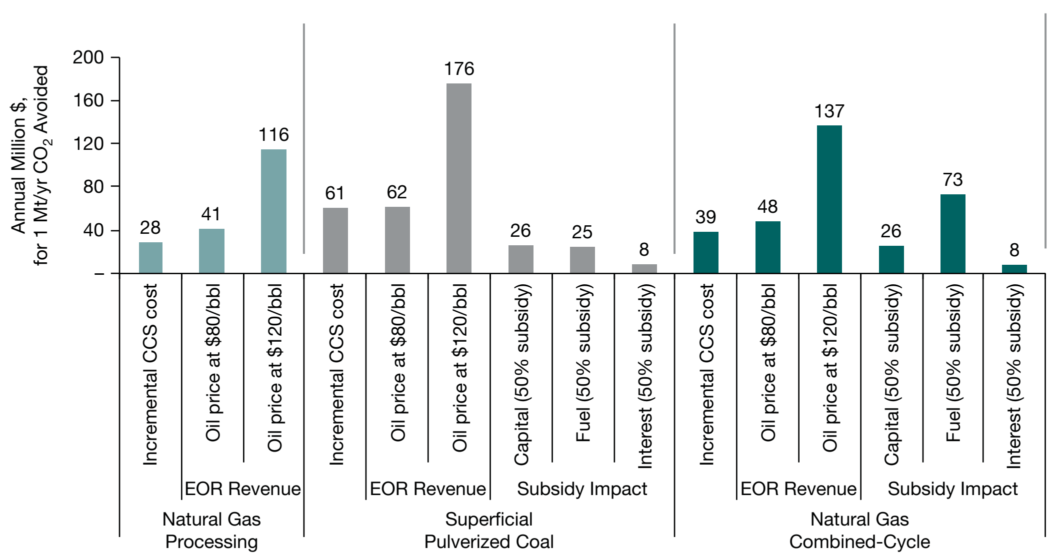
The analysis clearly reveals that CCS at natural gas–processing facilities offers the best gateway for broader deployment of CCS, followed by CCS at NGCC and SCPC facilities. The summary presentation of costs, EOR revenues, and subsidy impacts for each of the four countries is presented in the figures that follow.

In Figures 6.9–6.12, in the case of power plants, the cost associated for 1 Mt/yr of avoided CO_2 is based on the financing gap between the wholesale power price received by the generator and the LCOE of the power plant with CCS. This is because the cost of capture or abatement for the full CCS is based on the delta LCOE relative to the plant without CCS, which then reflects the true costs without any in-built market subsidy. By incorporating the market tariff that the power plant operator receives for electricity (for a plant without CCS) in calculating the delta LCOE of a plant with CCS, the analysis provides a better reflection of the actual costs (with the equivalent in-built market advantage) for a more even comparison with the gas-processing cases. However, this thinking does not of course incorporate any extra profit margin over that for a base plant (without CCS) that the power operator should take for a plant with CCS, which could be an issue for a policy debate and/or policy action.

For the gas-processing plants that emit pure CO_2, the capture (separation) units are already built into the plant and the cost is already included (more precisely, recovered) in the sales price of the natural gas. Consequently, for CCS, only the cost to dry, compress, pipeline, and inject (as relevant) the CO_2 underground are considered as incremental costs. In the illustrations, the cost for 1 Mt/yr CO_2 avoided refers to the net CO_2 injected.

These illustrations are for EOR revenues based on 0.32 tCO_2/bbl of incremental oil production. The analysis uses a reference of 1 Mt/yr CO_2 avoided as an illustrative reference, although the avoided CO_2 volume of the reference coal plant with CCS (546 MW net) is 2.8 Mt/yr and the CO_2 emissions

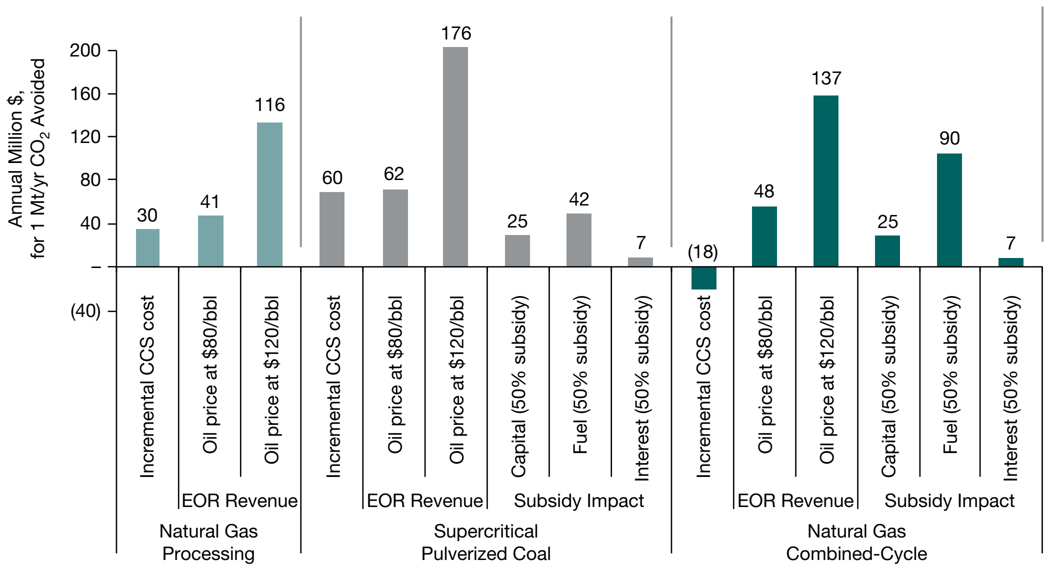
Figure 6.9 **Annual Costs, Enhanced Oil Recovery Revenues, and Subsidy Impact of 1 Mt/yr CO_2 Carbon Capture and Storage System in Indonesia**



bbl = barrel of oil, CCS = carbon capture and storage, EOR = enhanced oil recovery, Mt = megaton.

Note: For natural gas processing, the cost for 1 Mt/yr CO_2 avoided refers to cost for 1 Mt/yr net CO_2 injected. Incremental CCS costs are relative to the wholesale power tariff in the case of power plants.

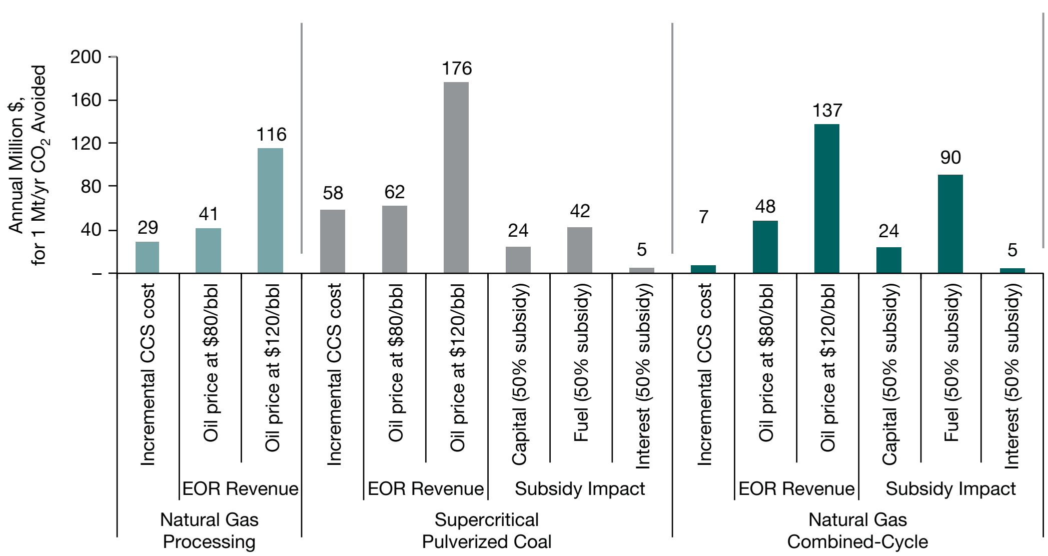
Figure 6.10 Annual Costs, Enhanced Oil Recovery Revenues, and Subsidy Impact of 1 Mt/yr CO_2 Carbon Capture and Storage System in the Philippines



bbl = barrel of oil, CCS = carbon capture and storage, EOR = enhanced oil recovery, Mt = megaton.

Note: For natural gas processing, the cost for 1 Mt/yr CO_2 avoided refers to cost for 1 Mt/yr net CO_2 injected. Natural gas-processing options were not specifically evaluated for the Philippines. However, this option is presented as an illustrative option should one emerge in the future. Incremental CCS costs are relative to the wholesale power tariff in the case of power plants. The negative incremental cost means that the incremental CCS is lower than the applicable wholesale prices.

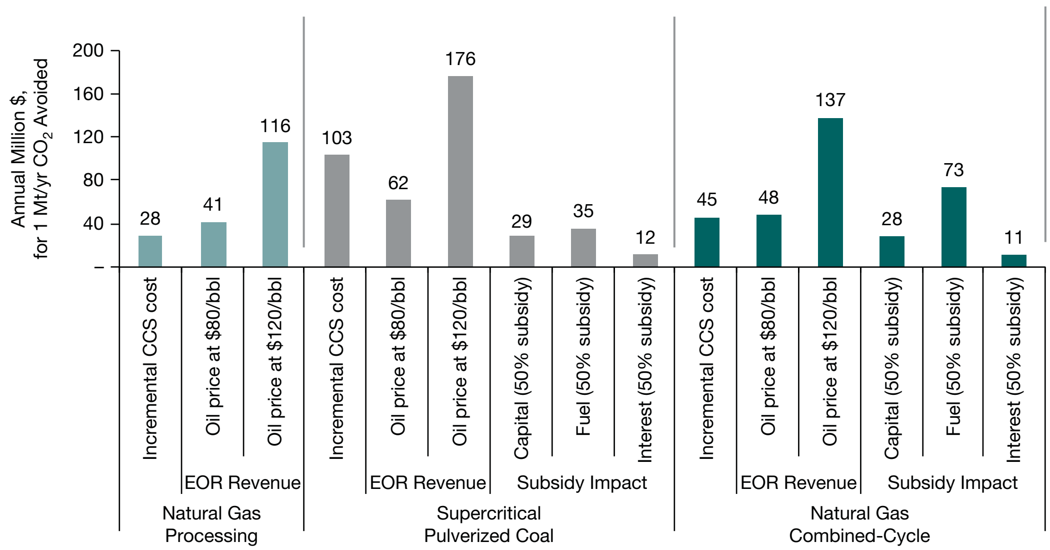
Figure 6.11 Annual Costs, Enhanced Oil Recovery Revenues, and Subsidy Impact of 1 Mt/yr CO_2 Carbon Capture and Storage System in Thailand



bbl = barrel of oil, CCS = carbon capture and storage, EOR = enhanced oil recovery, Mt = megaton.

Note: For natural gas processing, the cost for 1 Mt/yr CO_2 avoided refers to cost for 1 Mt/yr net CO_2 injected. Incremental CCS costs are relative to the wholesale power tariff in the case of power plants.

Figure 6.12 **Annual Costs, Enhanced Oil Recovery Revenues, and Subsidy Impact of 1 Mt/yr CO_2 Carbon Capture and Storage System in Viet Nam**



bbl = barrel of oil, CCS = carbon capture and storage, EOR = enhanced oil recovery, Mt = megaton.

Note: For natural gas processing, the cost for 1 Mt/yr CO_2 avoided refers to cost for 1 Mt/yr net CO_2 injected. Incremental CCS costs are relative to the wholesale power tariff in the case of power plants.

for the reference NGCC with CCS (482 MW net) is 1.1 Mt/yr.

Incremental CCS costs at natural gas processing plants (including injection costs) are generally lower than those of power plants and could be recovered through EOR revenues when oil prices are below $80/bbl (assuming 0.32 tCO_2/bbl). The exception to this is CCS in NGCC power plants in Thailand and the Philippines, where this power plant option becomes favorable due to the high electricity market tariffs available in these countries. The study recommends pilot CCS on natural gas–processing facilities in South Sumatra (Indonesia), Thailand, and Viet Nam.

With the exception of the power plant cases noted above for Thailand and the Philippines, NGCC and SCPC plants offer the next two highest CO_2 avoided costs. CCS on NGCC plants is the better of the two options because it requires lower revenues and subsidies. EOR revenues could help offset a large part of the CCS costs, though this will require oil prices of approximately $80/bbl–$100/bbl or higher, particularly for coal-fired power plants, to fully offset the costs. Subsidies targeting reductions in capital, fuel, or interest costs could help to offset some portion, but in themselves will not be able to defray a large portion of the CCS costs. In the case of the Philippines, where natural gas processing is not available and where the prevailing electricity market tariff is favorably high, NGCC power plants could be an early, economically viable option as a source of CO_2 for CCS.

The analysis unambiguously reaffirms the potential of EOR revenues in defraying CCS costs, independent of the capture source. In many instances, this EOR revenue may not entirely accrue to the CO_2 producer. It could instead flow to the government because of an oil production–sharing arrangement, or could be withheld by the oil producer depending on the exact nature of the production-sharing arrangement or other contractual arrangements in place. However, from a broader economic perspective, it is clear that no matter who is contractually entitled to the EOR benefits, EOR should be used wherever available to defray the initial costs and help build the basis for longer-term transition to storage. Consequently, for South Sumatra (Indonesia), Thailand, and Viet Nam where EOR opportunities were identified, the study recommends developing storage sites that are likely to offer EOR benefits.

It is important to recognize that the findings of this analysis could be influenced by a wide range of policy, cost, and technical developments. Some of the uncertainties regarding cost have been assessed in the sensitivities. However, other issues could have significant bearing as well. The timing of deployment could be impacted by a range of different policy considerations, for example cost–benefit of different mitigation technologies and rate of development of CCS technologies (especially the ongoing and anticipated cost reductions), which could in turn be impacted by the experiences of other countries. International and even domestic policy development could have a direct bearing on the cost economics. All of these could influence the overall recommendations on the timing and deployment of CCS options.

7 Legal and Social Issues in Carbon Capture and Storage

The development of carbon capture and storage (CCS) will require a supportive legal and regulatory framework that covers all aspects of CCS projects. Such a framework must provide an enforceable legal regime defining investment, ownership, CCS development activities, site operation, closure, post-closure, monitoring, reporting, remediation, health, safety, liability, and legally acceptable long-term stewardship of stored carbon dioxide (CO_2). None of the four countries covered in this study currently have such a comprehensive framework in place, though all of them have a wide variety of existing laws governing energy, resource exploration, and development which could be adapted for CCS.

The development, implementation, and enforcement of a legal and regulatory framework for CCS will require the engagement of a number of different agencies, entities, and stakeholders from within and outside of government. Such a comprehensive legal and regulatory framework is unlikely to evolve within a short time. However, such a framework is not essential to initiating a pilot project or perhaps even a demonstration project. These regulations could be developed in parallel with the pilot and demonstration projects so that a framework is ready by the time a commercial-scale project is under way.

The development of CCS also requires supportive public perception and social acceptability for the technology. These days, all large-scale energy projects routinely plan for broad-based stakeholder support and general public acceptability. For CCS, managing the social environment may be more challenging than other comparable large energy projects because it involves a wider array of issues that persist over a longer period of time. In contrast to power plants or oil and gas fields, for instance, CCS often requires public and private property for geological storage and for the storage to remain in place across generations. Public perception and social acceptability, therefore, must be a key consideration in the development of CCS.

7.1 Legal and Regulatory Framework

7.1.1 Stakeholders

Indonesia, the Philippines, Thailand, and Viet Nam have different political and legal systems with varying degrees of regulatory powers devolved to the local levels. Indonesia is a democratic, republic system in which regional governments have broad powers to make laws relating to public order, governance, and development. The Philippines is a democratic, republican state in which the political subdivisions of provinces, cities, municipalities, and autonomous regions enjoy considerable local autonomy in the development and exercise of local laws. Thailand is a constitutional monarchy under a democratic government. The country is divided into 77 provinces but the provincial governments have limited autonomy in making locally relevant legislation. Viet Nam is a single-party socialist country with government at both the local and central levels. The local governments are mainly charged with implementing regulations that are crafted and approved by the center.

Although the specifics will vary by country, CCS development within these countries will entail four broad clusters of state and non-state actors, as illustrated in Figure 7.1.

Leadership in the development of a regulatory and legal framework for CCS must come from the executive branch of government, which will involve several

Figure 7.1 **Key Participants in the Development of Carbon Capture and Storage Regulations**

NGA = nongovernment agency.

ministries in addition to higher levels of government, such as the cabinet. Although the specific responsible ministry varies across the four countries, and jurisdiction of the specific ministries may also vary, the process will broadly entail the list of ministries identified in Figure 7.1. Developing the regulatory and legal framework must also be supported by several government and nongovernment agencies. In several of the countries, government agencies are in the control of ministries, though many of them also operate independently. Relevant industries that will also need to play a role include oil and gas, power, and other energy-intensive industries (cement, iron and steel, fertilizer, and mining).

7.1.2 Existing Climate Change Policy

Indonesia, the Philippines, Thailand, and Viet Nam are all parties to the United Nations Framework Convention on Climate Change (UNFCCC) and the Kyoto Protocol. They are all non-Annex I countries and currently have no international obligation to reduce greenhouse gas (GHG) emissions. All four countries, however, have adopted several domestic policies aimed at enhancing mitigation and adaptation–related activities within their own countries and are active in international negotiations promoting the adoption of a long-term framework for GHG reductions. Key domestic GHG activities in the four countries are summarized in the following. In addition, they all have well evolved local processes to endorse, support, and promote projects under the Clean Development Mechanism (CDM) of the Kyoto Protocol.

- **Indonesia** announced its intention to reduce GHG emissions by 26% by 2020 relative to a business-as-usual case and offered to reduce emissions by up to 41% with international support. In September 2011, Indonesia adopted the National Action Plan on Climate Change through Presidential Decree 61, 2011. The action plan offers an integrated development strategy aimed at achieving the emission reduction targets announced by the president in 2009. In the energy sector, the plan proposes the use of geothermal and other renewables, and contemplates the deployment of CCS. It is estimated that CCS could account for 40% of the reduction from the power sector.

- **The Philippines** enacted the Climate Change Act of 2009, which requires government to systematically integrate climate change considerations in policy formulation, development plans, poverty reduction, and other development strategies. The law recognizes the vulnerability of the Philippine archipelago to climate change and calls upon the government to cooperate with the global community in addressing climate change.

- **Thailand** adopted a National Strategy for Climate Change Management in 2008. The strategy identified seven priority areas for emission reductions through efficiency improvements, increased use of renewable energy, and other means in electricity production, transportation, alternative energy sources, waste management and disposal, industrial processes and efficiency, agriculture, and cleaner production technologies. A National Climate Change Action Plan is currently being drafted by the Office of Natural

Resources in coordination with other ministries. In addition, the Ministry of Energy has adopted several policy instruments designed to promote the adoption of energy efficiency and increase the penetration of renewable energy electricity generation.

- **Viet Nam** has adopted the National Target Program to Respond to Climate Change (NTP-RCC). The prime minister chairs the national steering committee and the initiative is coordinated by the Ministry of Natural Resources and Environment (MoNRE). A key focus area within the NTP-RCC is the development of measures to enhance the adoption of energy efficiency. GHG mitigation efforts are focused on emission reduction opportunities in the power sector, and through greater use of natural gas. In transportation, the initiative seeks to improve public transport along with energy efficiency and conservation. MoNRE is currently developing a national strategy for climate change focused on low-carbon technologies and the development of low-carbon strategies supported by technology transfer.

7.1.3 Laws and Regulations Applicable to Carbon Capture and Storage

A comprehensive legal and regulatory framework for CCS will require a large number of issues to be well defined, including structure, operations, ownership, management, and monitoring, and especially starting with the definition for CO_2. None of the four countries currently have laws that specifically address the requirements for CCS. However, developing a CCS regulatory regime does not need to start from scratch: the countries all have existing laws and regulations that can be adapted to meet the requirements for CCS. In addition, emerging examples of fully developed regulatory regimes, such as in Alberta, Canada, could also be illustrative.

Regulations necessary to support the commercial development of CCS are outlined in Table 7.1. The table also highlights existing regulations that may be applicable and how those could be adapted to meet the requirements for CCS. Please note that relevant terms are defined at the bottom of the table.

Table 7.1 **Legal and Regulatory Framework for Carbon Capture and Storage**

<table>
<tr><th>Issue</th><th></th><th>Indonesia</th><th>Philippines</th><th>Thailand</th><th>Viet Nam</th></tr>
<tr><td rowspan="3">Classification of CO_2</td><td rowspan="2">Current status</td><td colspan="4">No legal definition of CO_2 as a pollutant currently exists, although it is referenced in some areas.</td></tr>
<tr><td>Oil and gas operators required to maintain CO_2 emissions inventory</td><td>Recognized as GHG but not as an “air pollutant”</td><td>Defined only as “by-product of petroleum”</td><td>No definition</td></tr>
<tr><td>Required for CCS</td><td colspan="4">Environmental protection laws and water regulations that include definition of “waste” and “pollution,” which could be used to classify CO_2.</td></tr>
<tr><td rowspan="3">Surface and subsurface rights for CO_2 transport and storage</td><td rowspan="2">Current status</td><td colspan="4">No laws for ownership, grant, or lease of surface or subsurface pore space for CCS currently exist. Only the government has power to grant mineral rights (including oil and gas), which are typically provided through production-sharing contracts.</td></tr>
<tr><td>Several types of land ownership rights are defined (freehold and right of use); typical duration of current rights for production sharing may be too short for CCS</td><td>Only Filipino citizens are allowed private ownership of land, though it can be leased to foreigners; subsurface rights are defined and can be obtained by private persons through lease, permit, license, or contract for a maximum of 25 years</td><td>Civil and land code offer conflicting definition of subsurface rights arising from land ownership; however, mature legal structure on existing mineral rights, with clear interpretation that state owns subsurface rights</td><td>Land use approval for industrial use currently provided for 50 years, extendable to 70 years</td></tr>
<tr><td>Required for CCS</td><td colspan="4">CCS will require long-term access through ownership, grant, lease, or contract to surface and subsurface rights, including access to pore space for storage.</td></tr>
</table>

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Table 7.1 *continued*

Issue		Indonesia	Philippines	Thailand	Viet Nam
Legal liability of CCS operations and for stored CO_2	Current status	No current framework for legal liability exists for CCS.			
		Liability defined through environmental regulations affecting upstream oil and gas production	Existing environmental liability funds (EGF, EMF, MRF) could be extended to CCS; tort law, which provides liability for damages, and Clean Water Act, which also provides for damages, can also be adapted	Government-managed NEF to environmental costs arising from CCS; Petroleum Act contains financial security requirement for decommissioning; defray costs	Law on Land holds land owners responsible for protection of land; recovery for environmental costs covered under oil-gas production-sharing contracts
	Required for CCS	Short-term and long-term liability can arise. Short-term liability relates to operations (environment, health, safety). Long-term liability could relate to environmental and health risks from leakage, contamination, or migration. Liability for CCS can be addressed by adapting existing liability rules for minerals.			
Environmental protection	Current status	No environmental protection rules are currently in place for CO_2 capture process, transport, injection, or storage.			
	Laws that may be relevant to CCS	Environmental Protection and Management (2009), Water Resources, Environmental Impact Assessment	Environmental Protection, Water Resources, (Clean Water Act, Code on Sanitation, Fisheries Code, Marine Pollution) Environmental Impact Assessment requirements	Environment Protection and Promotion Act, Groundwater Protection Act, Industrial Waste Regulations, Environmental Impact Assessment	Environmental Protection (2005), Water Resources, Environmental Impact Assessment
CO_2 transport	Current status	No existing regulator for CO_2 pipeline.			
		Upstream pipelines under jurisdiction of BPMIGAS under Law 22/2001 and MEMR Regulation No. 300 and Oil Gas Standard	Will require clearance under PICCS for transport; rules governing natural gas transmission, distribution and supply under Department of Energy may apply	Upstream pipelines covered by Petroleum Act under Department of Mineral Fuels (Ministry of Energy); downstream distribution pipelines regulated by ERC	MoIT governs siting of natural gas pipelines; MoNRE governs environmental standards related to pipeline
	Required for CCS	Clear regulatory and legal framework defining who can build, own, and operate pipelines (or other means) used to transport CO_2 for CCS.			
Health and safety	Current status	Standards for general occupational health and safety, as well as health and safety specific to oil and gas, are available. No standards specific to CCS currently exist.			
		MEMR Regulation No. 300 covers work health in oil and gas distribution pipeline and could apply to CO_2 transport	Occupational safety and health standards through DoLE	Occupational health and safety governed by Department of Mineral Fuels (Ministry of Energy)	Applicable occupational health and safety through MoL; safety issues in oil and gas covered by MoIT
	Required for CCS	A clear definition of health and safety for workers and of operations in CCS will be required, some of which will be adapted from existing rules.			

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Table 7.1 *continued*

Issue		Indonesia	Philippines	Thailand	Viet Nam
Enhanced oil recovery (EOR)	Current status	Limited regulations for CO_2-EOR are available in some countries.			
		Oil and gas exploration and production regulated under Law 22/2001 and GR 35/2004; awarded competitively through production-sharing contracts of 30–50 years	No EOR laws applicable to CCS; CO_2-EOR must be prespecified in work program or development plan for costs to be recovered; if CO_2 is only for storage, new law would be required	Ministry of Energy has jurisdiction over petroleum-related CO_2 streams since CO_2 is defined as a by-product under the Petroleum Act; Petroleum Act governs all aspects of oil and gas, and could be extended to cover CCS	No clear regulatory framework on EOR though permits to conduct test injections have been requested; several regulations governing EOR and enhanced gas recovery have been promulgated
	Required for CCS	A clear approach to how CO_2-EOR will be integrated into the production-sharing arrangement and built into oil-gas field development programs will be required.			
Foreign direct investment for CCS	Current status	Some controls on foreign investment in mineral exploration and production.			
		Foreign direct investment is governed by Law 25 (investment) and provides foreign-owned companies a 30-year period to operate, which can be extended by another 60 years	Generally open investment policy with some restrictions on sensitive areas; land ownership is restricted to Filipino citizens	Electricity, oil and gas, and mining are subject to foreign ownership restrictions	Projects with capital requirement greater than $1.75 billion require approval from National Assembly; investment in coal, oil, and gas must be approved by prime minister
	Required for CCS	A clear investment climate that supports foreign direct investment will be necessary for raising international funding for commercial-scale CCS projects.			

BPMIGAS = Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi (Indonesian Oil and Gas Upstream Regulatory Body), CCS = carbon capture and storage, DoLE = Department of Labor and Employment (Philippines), EGF = Environmental Guarantee Fund, EMF = Environmental Monitoring Fund, ERC = Energy Regulatory Commission, GHG = greenhouse gas, MEMR = Ministry of Energy and Mineral Resources, MoIT = Ministry of Industry and Trade (Viet Nam), MoL = Ministry of Labor (Viet Nam), MoNRE = Ministry of Natural Resources and Environment (Viet Nam), MRF = Mine Rehabilitation Fund, NEF = National Environment Fund, PICCS = Philippine Inventory of Chemicals and Chemical Substances.

Source: ADB analysis.

7.2 Public Perception and Social Acceptability of Carbon Capture and Storage

Projects with a large footprint invariably attract local and global attention. Experiences from several prior projects clearly show that public perception plays an important role in the success of the project. The influence of public perception and social acceptability on CCS is likely to be much higher. CCS projects require significant amounts of land for storage, involves the handling of a “pollutant,” and the project (i.e., storage) remains forever. All of these are issues that play readily into public perception and raise concerns about local, national, and international impacts.

The objective of encouraging public engagement on CCS is not merely to manage perceptions so that the project can move forward. Rather, the objective is to allow for meaningful processes to involve local and other stakeholders who will bear the direct and indirect impacts of project implementation. All four countries of this study require impact assessments to review the impact of large projects. Some countries, like Thailand, go further. The Thai constitution ensures the right of local government and civil society to participate in decisions regarding natural resources and the environment.

Studies conducted across many countries (e.g., Reiner et al. 2006, Ashworth et al. 2009) show that public awareness of CCS is low. Analysis performed by the study team confirms this in each of the focus countries. The analysis included an informal survey of stakeholders and review of the popular press on these issues. Broadly, public perception in the four countries suggests that people recognize that climate change and global warming are important challenges facing the world. They also recognize that CO_2 emissions are the key cause of climate change, that reductions of CO_2 emissions will help to mitigate climate change, and that action is required quickly on these fronts.

A review of the press coverage of environmental concerns in the local mainstream press indicates that these issues resonate readily with local communities. In several of these countries, the press was vocal and reported extensively on several large impacts. Most reports typically contrast positive (often economic) impacts with concerns about land availability; land, air, and water quality; livelihood; and economic empowerment. Organized and informal network groups are also active locally on these issues and offer a gateway to working with local communities on raising awareness and managing public perceptions.

However, the public in these countries knows little or nothing about CCS and has no clear appreciation of its advantages or disadvantages. In many instances, the fact that CCS is expensive and could lead to higher energy costs, particularly electricity, is the key concern. In addition, the lack of clear policies on CCS, the perceived environmental risks, low public understanding of the technology, and the absence of locally available capacity remain critical challenges to social acceptability of CCS.

The technical, commercial, and economic development of CCS in the four countries must be accompanied with a robust communication and engagement strategy that seeks to address why CCS is locally relevant. CCS is one of many climate mitigation options and policies, and recommending its adoption must be framed within this broader context, including various energy and development imperatives.

From the very onset, the communication strategy for CCS must seek to provide clear and reliable information to facilitate an understanding of the technology and issues involved in a way that is locally relevant. It must clearly characterize CCS's role in GHG mitigation, discuss its cost and technology impacts, and continually communicate information and seek input during the planning and implementation of pilot and demonstration projects.

CCS project development must also seek to engage, involve, collaborate with, and empower local communities where the projects will be located. Engagement must be at several levels: nationally with policy makers and industry; locally with local stakeholders likely to be affected by the physical footprint of the project; and broadly within scientific, social, and civic communities. The engagement process must allow for active consultation at all levels and across all stakeholders, and the development of legal and regulatory frameworks must actively solicit input from these communities. The economic and business models that will be used to finance CCS must be heavily influenced by local conditions, and ultimately contribute greater social, economic, and environmental (and collectively sustainable) development.

8 Road Map for Carbon Capture and Storage Development

Several past studies, particularly in Indonesia and Viet Nam, have advanced the discussion on the potential for carbon capture and storage (CCS) in Southeast Asia. This report acknowledges the foundation provided by these previous studies and seeks to build toward a more detailed and actionable road map for a pilot project in Indonesia, the Philippines, Thailand, and Viet Nam.

This chapter discusses main barriers and drivers to CCS development, followed by an outline of the proposed road map with recommended key activities, time line, and investment requirements for a pilot project that can be subsequently scaled up to a demonstration project and offer the basis for full commercial-scale CCS.

8.1 Barriers and Drivers for Carbon Capture and Storage

This study has identified 54 gigatons (Gt) of potential carbon dioxide (CO_2) storage capacity in four focus countries of Southeast Asia. Of these, 3 Gt are located in oil and gas fields, where knowledge of the storage potential is much more advanced and where many of the fields offer significant opportunities for CO_2-enhanced oil recovery (EOR). The study has also identified 200 megatons per year (Mt/yr) of emissions that can be captured from large point sources from a broad inventory sweep of sources. Based on the understanding and analysis of sources and sinks, the report has identified several future commercial and initial pilot CCS projects, which were discussed extensively in Chapter 5.

While opportunities for CCS clearly exist, the context for CCS in the four countries is more complex than merely identifying possibilities. Efforts to pursue a development strategy must be framed within this larger context recognizing the economic, social, legal, and political complexities that will surround the development of CCS. Key issues are highlighted in the following and have also been discussed more extensively in previous chapters.

The region has **limited technical experience** in operating reservoirs with CO_2-EOR or any other kind of subsurface CO_2 storage. Technical capacity will therefore need to be built up to support large-scale CCS development. More widely, the technology and its associated benefits and risks are poorly understood, and there is very little appreciation of it within the policy-making framework.

Energy costs are already **high**, relative to average per capita income. Proposals for projects that could raise energy prices due to the currently higher capital costs of plants with CCS will be met with stiff political and social resistance.

The four countries are **highly dependent on imports for energy**. This extends beyond dependence on oil (with the exception of Indonesia, which has abundant coal and gas reserves). The Philippines and Thailand are already dependent on imported coal and are expected to become increasingly dependent on natural gas. Viet Nam's indigenous coal resource is anthracite, which is not well suited for power generation. Future power plants in Viet Nam are expected to use imported coal. Similarly, locally available lignite coal in Thailand is not well suited to its use in advanced supercritical power plants. There is a risk that CCS with higher energy losses could increase the cost of imported fuels for power generation. Some of that will, however, depend on how future global prices for coal and gas are driven by increased supply and demand from recent discoveries of potentially large unconventional gas resources worldwide.

No clear legal and regulatory framework for CCS currently exists. Large-scale CCS applications are unlikely until a clear legal and regulatory framework is first in place. However, projects that are pilot scale could be conducted using existing laws and regulations.

Despite several programs to promote the use of clean energy, enhance energy efficiency, and adopt clean technologies, all four countries have **no obligation to reduce GHG emissions** under a climate change protocol.

Against the challenges of CCS development is the fact that Indonesia, Thailand, and Viet Nam are well positioned for CCS with their potentially inexpensive large sources of CO_2 from natural gas–processing facilities. This is likely to increase in the future as gas fields with higher concentrations of CO_2 come into production. Unlike the other three countries, the Philippines does not possess a ready CO_2 source from natural gas processing, though there are other strong emission candidates in coal and natural gas power plants. Furthermore, all countries could benefit from CCS if the global prices for coal, gas, or both decline as a result of the large supply from recently discovered unconventional gas resources, which in turn increases the use of coal or gas in power generation.

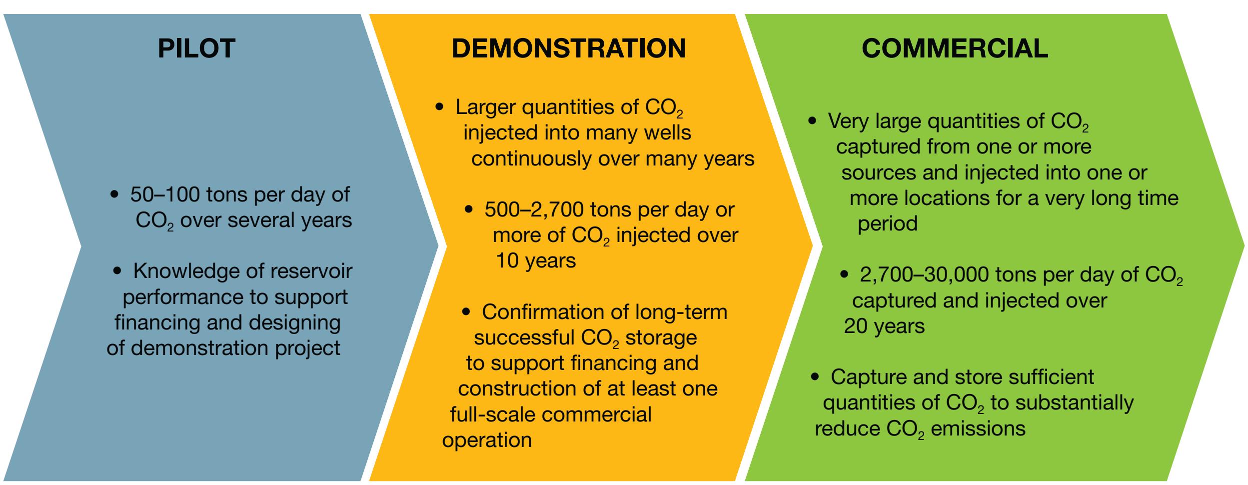
Indonesia, Thailand, and Viet Nam also possess strong opportunities for CO_2 storage through CO_2-EOR. In Indonesia and Viet Nam, some testing and additional studies are already taking place in this area. Efforts to accelerate the development of CO_2-EOR will also facilitate a closer look at CCS.

Each of these four Southeast Asian countries is extremely vulnerable to the impacts of climate change. There is already solid appreciation of the need to act locally on efforts to mitigate and adapt to climate change, while also supporting efforts to achieve a global consensus on climate action. A CCS development strategy that offers financing and economic support to defray costs, provides capacity building and technical support, supports local imperatives, and provides a narrative on CCS as an important mitigation strategy within a portfolio of national options could resonate well publicly and politically.

8.2 Carbon Capture and Storage Development Strategy

A strategy to develop CCS will generally evolve over three phases, starting with a pilot, progressing into a demonstration, and finally growing to commercial-scale projects (as illustrated in Figure 8.1). Though the evolution increases the CO_2 volume from one stage to another, there are several other important parameters regarding technological, financing, legal, regulatory, and social issues that need to be aligned to build the basis for eventual commercial-scale application.

Figure 8.1 **Stages of Carbon Capture and Storage Development**



The key elements in the evolution of the strategy are discussed in the following.

Stages of Carbon Capture and Storage Development: CCS development, irrespective of country, will broadly trace the following path:

(i) Pilot-scale operation of at least the storage portion of the project, at a location assessed to have long-term storage potential. The first choice for CO_2 storage operations would ideally be where there is an opportunity for EOR. Pilot operations may include two subphases: single-well and multi-well.

The single-well is typically designed as a "huff and puff" pilot where data are collected during different stages (i.e., injection, soak, and production periods) to measure reservoir response to injected CO_2. These data are matched with a reservoir simulator model which is then used to predict the long-term response of the reservoir to CO_2 flooding (Gunter et al. 2008).

The multi-well phase is typically a five-spot arrangement with either four injection wells plus a central production well, or four production wells plus a central injection well. The pilot would run until the expected response for the predicted enhanced recovery is seen at the production wells, followed by an injection-only storage, then followed by a shut-in stage. Other configurations are possible depending on the access to existing wells (Hitchon 2009).

(ii) Single-project demonstration, at or near commercial scale, of 500–2,700 metric tons CO_2 per day captured and stored. A commercial source of CO_2 will be required in time for the storage demonstration.

(iii) Widely applied CCS operations at commercial scale (2,700–30,000 metric tons per day, per project).

(iv) In the case of CO_2-EOR transitioning to CO_2 storage, there may be an opportunity for smaller CO_2 commercial storage projects due to the existing infrastructure and offset provided by the income generated from the oil production.

A small pure CO_2 stream is the ideal source for a storage pilot. The ideal source of CO_2 for pilot-scale operations is either an existing industrial manufacturing facility or an onshore gas-processing plant that produces a stream of almost-pure CO_2.

A storage pilot should not be made dependent on a CO_2 source pilot. CO_2 capture technology could be piloted in parallel with storage pilot operations. The success of the storage pilot should not be made dependent on the success or timing of a CO_2 capture pilot.

For capture, a new base power plant will be preferable to retrofitting an old one. For post-combustion CO_2 capture sources from power plants, a new power plant would be preferable. Failing that, the next best alternative may be the repowering of older equipment. Retrofitting operating plants would be the least preferred option. If the source is a coal-fired power plant, a supercritical unit should be preferred to subcritical steam cycles. For open cycle natural gas turbines, retrofitting CCS should be supported by repowering in a combined-cycle mode.

Pipelines would be the preferred option for transporting CO_2. Transporting CO_2 by pipeline is the most likely means of moving large quantities of CO_2 from source to sink for demonstration and commercial projects. Pipeline CO_2 transport is assumed to be technically proven. Nonetheless, nontechnical socioeconomic and regulatory barriers may need to be overcome before CO_2 transport becomes feasible, particularly if the pipeline is onshore for any part of its length.

Funding support will be necessary to support CCS development. Early application will require substantial financial assistance from developed countries or from domestic support mechanisms to meet increased capital requirements and operating costs for CCS enabled plants.

CCS development will require inputs in at least five areas:

(i) **Technical:** capture, transport, and storage; identifying and implementing promising opportunities at both pilot and commercial scale.

(ii) **Regulatory:** establishing the regulatory framework for CCS from pilot to commercial scale.

(iii) **Socioeconomic and environmental:** public outreach/education, and environmental and socioeconomic impact assessment.

(iv) **Financing:** putting in place the required funds and business structural provisions to enable first-of-a kind and commercial CCS projects.

(v) **Public stakeholders:** activities of nongovernment organizations that represent public stakeholders and support the development of broader public acceptance of CCS.

CCS development must emphasize capacity building and local ownership. Local personnel must be present and actively involved throughout the project development cycles. This will provide opportunities for capacity building and minimize the need for international technical assistance by the time of the demonstration project.

In addition, a key aspect of the CCS development process is the learning that must transfer from CCS project developments in other parts of the world and on local capacity building. Companies engaged in CCS—oil and gas companies, for example—must be able to learn from ongoing project developments in other parts of the world. Capacity building of local stakeholders must occur across all of the different aspects of project development: technical, financial, environmental, community engagement, regulatory, and legal. Capacity building is also required on the institutional mechanisms to develop and implement the appropriate regulatory and legal framework for CCS. The road map proposed in this report provides an opportunity for capacity building across all of these areas.

8.3 Road Map for Carbon Capture and Storage

This section discusses the specific road map for CCS. The road map has two broad sections: activities related to pilot project plus subsequent follow-up activities leading to demonstration and finally commercial-scale projects. Both are discussed in turn. Although the implementation of this road map may vary slightly across the countries to account for the specifics of each project and context, the recommendation is that CCS development in any of the four countries follow this development pathway.

8.4 Pilot Project Activities

The key consideration for a pilot is that it must yield information that will enable the accurate prediction of conditions in a larger demonstration or commercial operation. While a pilot operation may produce some incremental oil, its primary purpose is to gather information. In addition, conventional hydrocarbon production, e.g., oil or gas production, might even be temporarily impaired during the piloting process.

The integrated road map, covering all of the aspects required for CCS pilot, demonstration, and commercial activities, is outlined in Table 8.1. The road map broadly extends over 15 years, at which point there should be enough of a basis for commercial-scale CCS to begin. The total investment outlay to support the pilot and demonstration project (the latter injecting 1 Mt CO_2/yr for 5 years) is expected to be around $1 billion (covering a 15-year period per country), inclusive of the administrative, feasibility, technical studies, and project costs, though these costs could vary significantly based on project specifics. The cumulative investment cost of $1 billion breaks down into $54 million over the first four years of the pilot, $407 for the demonstrating project (years 5–9) leading up to start of the CO_2 injection of 1 Mt/yr in year 10, and the remainder for 5 years of injection in the demonstration project (years 10–15). The biggest sensitivity in these costs is the price charged by the CO_2 producer. Table 8.1 is designed to provide a high-level illustrative view, including a broad assessment of costs.

Growing the pilot phase along the road map guidelines will be controlled by five stage gates. These gates are in place to ensure that progress to the next stage occurs only if the previous stage produces an outcome that can then serve as the basis for the next. Broadly speaking, the five gates are the following:

Gate 1: Pilot CO_2 source and storage site have been identified; owners/operators are contracted.

Gate 2: Pilot funding has been secured; proper permits have been secured.

Table 8.1 **Illustrative Road Map for Carbon Capture and Storage Development**

	PILOT					DEMONSTRATION			COMMERCIAL	
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8–9**	**10–15**	**15+**
	Gate 1: Pilot identified; parties contracted	**Gate 2: Pilot funding secured**	**Gate 3: Pilot construction completed**	**Gate 4: CO_2 Injection of 50–100 tons/day successful**	**Gate 5: Case for demonstration project established; business relationship secured**		**Demonstration funding secured**	**Demonstration construction completed**	**CO_2 injection of 1 Mt/yr successful**	**Commercial project development**
CAPTURE TECHNICAL	Identify CO_2 pilot and commercial sources	Detailed capture pilot design	Pilot construction	Capture CO_2	Confirm demonstration project for CO_2 sourcing	Commence detailed design of CO_2 capture demonstration project	Complete detailed CO_2 capture design and cost estimate	Construct demonstration project	Start up and operate demonstration project	Depending on the success of demonstration project, modify demonstration capture plant to provide a commercial CO_2 supply
TRANSPORT TECHNICAL	Identify transport needs (pipeline for on-shore and off-shore commercial project)	Design pilot transport system	Construct or procure pilot transport system	Transport CO_2 for pilot	Confirm CO_2 transport demonstration system	Commence detailed design for CO_2 pipeline	Complete detailed design and cost estimate	Construct CO_2 pipeline	Start up and operate CO_2 pipeline	Pipeline for demonstration project should have been sized for commercial throughput
STORAGE SITE	Plan storage site (screening and selection)	Design, site characterization, monitoring plan, risk assessment planning	Pilot construction, pilot injection and production plan, monitoring baseline, risk assessment planning	CO_2 injection, data collection and modeling, monitoring and interpretation, risk assessment	Pilot shut-in, pilot assessment and prediction, monitoring and interpretation, risk documentation	Commence detailed design for storage demonstration	Complete detailed design and cost estimate	Construct demonstration project site	Start up and operate demonstration project site	Depending on success of demonstration project, initiate commercial project discussions
LEGAL/ REGULATORY	Develop approach to regulate storage pilot (identify specific laws and regulations that would be involved and propose modifications)	Obtain permits to construct and operate pilot	Pilot project reporting	Pilot project reporting	Draft demonstration-specific regulation and legislation (for demonstration, including subsidies/tariffs)			Apply for permits to operate, if applicable	Reporting	Draft full CCS legislation and regulations
SOCIOECONOMIC/ ENVIRONMENTAL	Information, educational, and communications; and advocacies for CCS, preliminary risk and environmental impact assessments (EIAs)	Public consultations at pilot sites (press releases on detailed risk and EIAs for offshores)	Obtain environment permit to operate pilot(s)	Provide pilot project report to environmental agencies and the public	Define scope and EIA for demonstration project	Prepare EIA that promotes extensive public engagement for demonstration project	Reporting to public	Reporting to public	Reporting to public	Reporting to public

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Table 8.1 *continued*

	PILOT				DEMONSTRATION				COMMERCIAL	
	1	2	3	4	5	6	7	8–9	10–15	15+
	Gate 1: Pilot identified; parties contracted	Gate 2: Pilot funding secured	Gate 3: Pilot construction completed	Gate 4: CO_2 Injection of 50–100 tons/day successful	Gate 5: Case for demonstration project established; business relationship secured		Demonstration funding secured	Demonstration construction completed	CO_2 injection of 1 Mt/yr successful	Commercial project development
FINANCING	Plan design and cost estimates	Detailed pilot cost estimate, including pilot CO_2 sourcing	Engage and train pilot project/ operation staff	Engage potential funding partners (donors, private sectors, etc.) and operators (if different from pilot project)	Define business partnership for overall CCS demonstration project	Develop pro-forma business reporting mechanism with partners	Funding available for construction of demonstration project	Funding available for operation (including staff)	Reporting and payback	Will require worldwide consensus on CCS that makes it intrinsically less expensive to proponents than other alternatives in their control
ADMINISTRATIVE AND STUDIES COSTS— ANNUAL ($ million)	1.5	3	1.5	3	3	1	1	1	1	TBD
PROJECT COSTS — ANNUAL ($ million)		5	20	20	5	20	175	100	80	TBD
CUMULATIVE COST ($ million)	1.5	9.5	31	54	62	83	259	460	947	TBD
GOVERNMENT AND OTHER (as necessary)	Conceptualize specific demonstration and commercial development paths and incentive packages	Commitment and support of government for CO_2 reduction (policy intervention, government incentive programs on CCS)		Government support for CCS demonstration projects in the form of subsidies, incentives, and legislation			Finalize concessions/ incentives			Established policy that supports CCS on a wide scale and/or penalizes non-performance on greenhouse gas reduction

CCS = carbon capture and storage.

Gate 3: Pilot construction has been completed.

Gate 4: Injection of 50–100 metric tons of CO_2 per day has been successful.

Gate 5: Case for a storage demonstration is approved based on a successful pilot assessment; business relationship for demonstration project secured.

A discussion of these elements of the road map follows.

Technical Assessment for Storage with or without EOR: This study has identified several attractive oil and gas field storage sites that have sufficient capacity for EOR and/or commercial storage operations. These sites must undergo a detailed reservoir characterization and assessment based on existing information from the operator. Reservoir simulators will have to be calibrated by matching historical data from existing primary and secondary production data. The data can then be used to design the pilot phases, including injection rate. If additional data are required to enhance the model and provide a sufficient basis for an adequate risk assessment, a data collection plan should be undertaken. During the active pilot phase, data will be compared to model predictions and the simulator recalibrated if necessary. The final result will be a calibrated simulator that can be used to predict the attractiveness of an EOR and/or storage demonstration in the piloted oil or gas reservoir.

Storage Site Development: There are several alternatives for the piloting process based on the technical assessment. The most expensive parts of the pilot will be the purchase of CO_2 and the drilling of new wells. Consequently, the pilot site should depend on both the availability and suitability of the oil or gas reservoir and the existing well spacing. If the wells are not close enough for a reasonable response time from an injection–production well pair, then a decision should be made whether to drill a new well between the two existing wells. The decision should be based on broader considerations such as planned future infill drilling. If no more drilling is planned, and the existing wells are too far apart, then the pilot could become a short-term single well "huff and puff" CO_2 injection/soak/production test, with the option of a multi-well pilot if the single-well test is successful.

Based on the above discussion, existing infrastructure for the storage site will need to be assessed. This should include drilling new wells if needed, and/or using existing wells. Transporting the CO_2 by truck or boat for the pilot may also necessitate the procurement of a bullet for CO_2 storage and a compressor to inject the CO_2.

Monitoring: A monitoring plan will have to be developed based on preliminary predictive modeling. This plan will determine periodic monitoring activities and choose monitoring tools with sufficient sensitivity to collect data relating to reservoir conditions and characteristics. The selected measurement tools will need to be procured and located appropriately on the surface and in the subsurface, and baseline information will need to be collected before injecting the CO_2. The tools will be used to continuously collect data during the active pilot phase, and also after the active pilot phase (shut in). The collected data will be used to model fluid movement and risk assessment. Monitoring will be hierarchical in space and time and organized around key risk events, and the tools can change with time in response to the type, complexity of technical concerns, and the most cost-efficient monitoring methods. Monitoring will be carried out before any injection, during injection, and during the final shut-in period.

Risk Assessment: A risk management plan will have to be created based on existing data. The main focus of this activity should be storage. Based on modeling, a technical storage risk assessment plan will be created which identifies, assesses, and ranks key risks and associated uncertainties, their monitoring, and/or mitigation. It will also be necessary to establish performance metrics and set triggers that signal required actions for minimizing risk. During the active pilot phase, the likelihood of the risks occurring will be monitored, and the risk assessment plan can be adjusted as necessary to allow further action to be taken where required. During the final stage of the pilot, the risk assessment plan will be further modified and documented for use in any future activity in the reservoir. If the review identifies risks or uncertainties that are still not properly addressed or documented, then some actions will be necessary to update or complete the project risk catalog.

Capture Site Development: A relatively inexpensive source of CO_2 offering several hundred metric tons per day needs to be identified. An agreement for procuring the CO_2 supply has to be reached with the operator/owner. This will determine the relevant equipment needed to condition the gas for transport. To produce transport-ready CO_2, requirements for additional supporting equipment must be identified and installed. Toward the conclusion of a successful pilot, a CO_2 source capturing up to 2,700 metric tons of CO_2 per day must be procured to supply the demonstration project.

Transportation Development: Considerations in conditioning the gas suitable for transport and injection are discussed under "Capture Site Development" and "Storage Site Development." At this stage, an assessment is required to select the most appropriate transportation mode—truck, boat, or pipeline—to supply the CO_2 to the pilot storage site.

Toward the conclusion of a successful pilot, the construction of a pipeline should be proposed to link and/or cluster a larger CO_2 source to the potential storage site, which will have a capacity of over 2,700 metric tons per day.

Financing: A preliminary project costing analysis will have to be evaluated, and seed funding will need to be secured to enable site characterization and pilot design. This should be followed by final project costing and securing the necessary funds for constructing and executing the pilot. A similar exercise will need to be carried out for the demonstration phase. If the storage is integrated with EOR, the operator will also need to evaluate the implications of any profit sharing contracts and taxation regimes on project cost (if any), and engage accordingly with the relevant authorities.

Legal/Regulatory: It will be necessary to identify existing laws that can play a role in executing the pilot project. For those areas of the pilot not covered, a regulatory pathway still needs to be negotiated, possibly under an "experimental" classification. Based on this, the pilot plans will be submitted to the regulators to obtain an operating permit. This permit application should describe the reporting that will be carried out during the active pilot stage. At the conclusion of the pilot, the results should guide the development of the regulations necessary for the demonstration and commercial phases.

Socioeconomic/Environmental: On the regulatory side, an environmental impact assessment (EIA) will need to be performed. The execution of EIA documents must proceed in parallel with managing social issues and monitoring the public's perception of CCS. There must also be appropriate social engagement on the project, including direct meetings with stakeholders at all levels as appropriate.

Government: Project development should include a dialogue with policy makers on the potential role of CCS in achieving deep reductions in CO_2 emissions.

Capacity Building: A program for capacity building for the implementation of CCS should be developed for stakeholders. This outreach should be to all stakeholders, with specific programs tailored to address the different needs of the research and development, technical community, regulators and government agencies, the financial community, academia, and the public.

8.5 Implementing the Road Map: Carbon Capture and Storage Working Groups

Implementing this road map cannot be led by any one agency or ministry alone, and instead requires the engagement of a wide group of authorities. As part of this regional technical assistance project, a working group on CCS was established in each of the four countries. These working groups reflect broad-based representation, including from the relevant ministries (energy, environment, finance, industry, planning, and investment), industry groups, nongovernment organizations, technical experts, financial institutions (domestic and international), and academics.

This working group, or its successor, must be institutionally integrated within government, empowered with budgets and decision-making ability so that it can lead and manage the evolution of CCS effectively.

9 Conclusion and Recommendations

Carbon capture and storage (CCS) has a clear role to play in the national energy strategies of Indonesia, Thailand, and Viet Nam, while in the Philippines, its role is less clear. Nevertheless, CCS technology offers a development pathway that can help meet the region's swiftly growing energy demand while simultaneously reducing the carbon dioxide (CO_2) emissions produced in these countries.

Evidence regarding expected growth, energy use trends, and development imperatives clearly suggests that over the next 2–3 decades, these countries will remain dependent on fossil fuels even as they continue to increase their use of renewable energy and energy efficiency, and earnestly begin to transition toward low-carbon economies. As part of a broader strategy on energy and climate, CCS facilitates this eventual transition by removing large volumes of CO_2 emissions from the use of fossil fuels, and therefore plays an essential part of an evolving low-carbon economy.

9.1 Carbon Capture and Storage Opportunities Are Available

The study establishes that applying CCS is technically feasible in all of the four focus countries. The four countries have abundant CO_2 sources and storage sites, though in the Philippines, CCS relying on conventional storage opportunities only exists in the longer term, if at all, while near-term opportunities for storage may be limited to nonconventional storage sites, which will need further analysis and review over the next 5 years. The ranked emission sources, which met the qualifying criteria and were located in the regions of focus (i.e., South Sumatra in Indonesia, CALABARZON in the Philippines, Thailand, and Viet Nam), collectively offered about 170 megatons (Mt) of CO_2 annually. The best existing capture sources are natural gas processing and power plants (supercritical pulverized coal [SCPC] and natural gas combined-cycle [NGCC]). Natural gas–processing facilities in Indonesia and Thailand offer the cheapest source of capture, followed by CCS in NGCC and SCPC plants. The region is also building several new power plants, which are strong prospective candidates for capture. In addition, future gas production in Viet Nam is likely to involve high-CO_2-content natural gas which must be stripped and will offer the lowest-cost, steady stream of CO_2 for CCS. The Philippines currently has no identified prospects for exploiting high-CO_2-content natural gas resources.

The study has identified CO_2 storage potential of approximately 55 gigatons (Gt) that could be accessible to emission sources in the four countries. The bulk of this storage potential is only determined as a resource (i.e., theoretical storage potential based on porosity estimates) found in saline aquifers and coal beds. This estimate of storage includes approximately 4 Gt of effective storage potential (i.e., a potential reserve number) in oil and gas fields, several of which offer the potential for CO_2-enhanced oil recovery (EOR).

The best storage sites are within 300 kilometers (km) of potential CO_2 sources and often within 150 km. The exception to this is the Philippines, where the leading candidate for CCS contains a source and sink combination that is over 300 km apart. However, the large distance between the source and sink in the Philippines could be offset by the availability of an existing pipeline network. Similarly, potential CCS applications in the other three countries could take advantage of existing transport networks that are currently being used for the oil and gas fields, but which could later be deployed to transport CO_2.

9.2 Recommendations for Pilot Projects

In each of the four focus countries, the study has identified specific capture sources and sink sites that could be suitable for a pilot project. The pilot project sites were pointedly selected to facilitate the eventual development of demonstration and subsequently commercial projects. Consequently, the recommended pilot storage sites have been selected because they would be appropriate as initial commercial storage sites. The pilot capture sources could also transition into demonstration and commercial-scale applications, but could also be supplemented or replaced with other sources as the CCS project development moves into the demonstration or commercial phases.

In South Sumatra (Indonesia), the CCS pilot recommendation is to match a particular natural gas–processing facility with onshore oil and gas fields in the South Sumatra Basin.

Similarly, in Thailand, the appropriate starting pilot may be to match a particular natural gas–processing facility with the oil and gas fields in the Gulf of Thailand, or to match a particular repowered coal-fired power plant in the north with onshore oil and gas fields.

In Viet Nam, the proposed pilot is to match a NGCC power plant with the offshore fields in the Cuu Long Basin off the coast of South Viet Nam.

In the Philippines, the best pilot project option would be to match the power plants in CALABARZON with the gas fields off the islands of Palawan. Unlike the other countries, the pilot in the Philippines is unlikely to start for 20 years because the proposed gas fields will not be available for CO_2 storage prior to that time. Consequently, some promising prospects in geothermal and ophiolite sites have also been identified for preliminary investigation as potentially novel forms of geological storage.

9.3 This Study Offers a Road Map for Carbon Capture and Storage Development, Starting with a Pilot Project

The study has outlined a detailed road map stretching over 15 years which aims at piloting CCS, developing a demonstration project, and building the basis for the commercial application of CCS. The road map outlines the schedule for all activities related to project development, with the most amount of detail directed at the pilot phase. The pilot process is governed by five milestone-based gates to help manage pilot progress in the project development cycle. A detailed plan for the demonstration phase, including a commercial supply of CO_2, can be developed later based on results from the pilot.

A pilot project, achieving about 50–100 metric tons of CO_2 injected per day, is estimated to require a capital outlay of about $50 million–$60 million and then transition into a demonstration-scale project in the sixth year. Building on the pilot, a demonstration project injecting about 2,700 metric tons of CO_2 per day is expected to require an additional $900 million and be operational between years 10 and 15.

The study recommends that a pilot and subsequent demonstration be selected with future commercial projects in mind. The pilot should be primarily designed to provide information about the storage site. This means that the pilot should be based on the storage site where the first commercial-scale CCS project will eventually be located.

9.4 Natural Gas Processing Offers the Best Entry Point

The best entry option for CCS is through natural gas–processing facilities. These facilities offer a cheap source of CO_2, at levelized cost of approximately $30/t net CO_2 injected. In comparison, the abatement costs of CCS on supercritical pulverized coal plant and natural gas combined cycle plant are approximately $93/t and $97/t$CO_2$ avoided, respectively. However, in the case of power plants, the prevailing electricity tariff could change this relative ranking and could favor capture from an NGCC power plant over that from a supercritical pulverized coal plant. This is particularly the case when NGCC receives a higher wholesale power tariff as is the case in some countries.

The study recommends that whenever possible, a natural gas–processing facility should be used in the pilot, demonstration, and early commercial-scale projects. Natural gas processing with CO_2 suitable for capture is available in every country except the Philippines. Some of the new gas fields in Indonesia and Viet Nam are likely to involve high CO_2 content and could provide a reliable source of CO_2 for capture well into the future. Capture of at least 1 Mt of CO_2 per year is possible from these facilities. As CCS develops and larger volumes of CO_2 are required for commercial applications, coal and natural gas power plants may need to be developed for their larger CO_2 volumes, but will entail substantially higher costs than from natural gas processing.

9.5 CO_2-Enhanced Oil Recovery, When Available, Represents a Good Financing Option for Initial Carbon Capture and Storage Projects

CCS will entail higher costs than those for plants without CCS. The LCOE of a SCPC plant with CCS exceeds the LCOE of a reference SCPC plant without CCS by \$57/MWh–\$66/MWh across the four countries, while the LCOE of a SCPC plant with CCS also exceeds the generation power tariff for coal by \$55/MWh–\$103/MWh.

Similarly, the LCOE of a NGCC plant with CCS exceeds the LCOE of a reference NGCC plant without CCS by a range of \$30/MWh–\$32/MWh. The LCOE of NGCC with CCS exceeds the generation power tariff for gas by a range of \$2/MWh–\$45/MWh. In the Philippines and Thailand, the LCOE of a NGCC plant with CCS is higher than the generation power tariff by a much lower increment of \$2/MWh and \$7/MWh, respectively. In all four countries, the lower incremental power cost of a NGCC plant with CCS suggests that this option is more favorable than a coal-fired SCPC plant with CCS.

Where applicable and feasible, CO_2-EOR provides a good entry point for CCS, especially in the context of uncertainties of a global climate regime. It provides strong first-step financial support by providing a revenue stream against the CO_2. Assuming CO_2-EOR productivity of 0.32 tCO_2/bbl, an oil price of approximately \$70/bbl could provide the implied revenues from EOR (assuming that onshore and offshore production costs for EOR are similar) to fully defray the incremental cost of CCS in natural gas–processing facilities. At the same CO_2-EOR productivity levels, oil prices of \$80/bbl–\$100/bbl could defray the additional costs of CCS from coal and natural gas power plants, being at the lower end of this range for NGCC with CCS power plants.

When EOR revenues and other CO_2 support credit prices are either not available or not adequate, a mix of domestic and international financial support measures will be required to defray the incremental costs for CCS. Domestic financial support will typically involve specialized tax incentives that reduce import costs, lower taxes, and speed up depreciation. It can also involve extension of incentives, such as feed-in tariffs or adders, risk guarantee, and credit extensions that are afforded to renewable energy generation or energy efficiency programs. However, these domestic programs on renewable energy and energy efficiency are small relative to generated volume of a plant with CCS. Extending the same level of benefits will impose a higher cost on consumers or public finances if the program is being publicly subsidized.

A key source of funding support will likely need to come from international sources, including development agencies, multilateral agencies, and commercial-level borrowing. The support measures could be packaged as concessional debt, capital grants, risk guarantees, or other instruments that defray the initial cost outlay.

9.6 Existing Legal and Regulatory Frameworks Could Be Expanded for Carbon Capture and Storage

None of the four countries have any specific regulations or legal frameworks governing CCS. Most countries have yet to define CO_2 in a way that will allow subsequent regulations to be framed. However, all of the countries have existing regulatory frameworks covering surface and subsurface rights and environmental concerns, including land, air, water, and impact assessments. These regulations can be adapted to apply to CCS. In addition, several other key regulations will need to be framed to cover health and safety, liability, investment, ownership, and CO_2 transport, most of which can also be adapted from existing regulations.

Developing a comprehensive regulatory framework for CCS will involve several ministries, agencies, and nongovernment stakeholders. The study recommends that the framework be developed in parallel with the pilot and demonstration projects so that it is in place by the time a commercial-scale CCS project is ready for deployment. The pilot and demonstration project can proceed with changes to a few select regulations that are just enough for these specific projects at the same time as the broader framework is being prepared.

9.7 Communication and Engagement Strategies Must Play an Essential Role in Developing Carbon Capture and Storage

Public perceptions are often the most understated challenges to developing and deploying new technology. In this case, there is little public awareness about CCS. An effective communication strategy and campaign will be needed to ensure appropriate awareness building about CCS technology. The study recommends that such communication strategies be developed and deployed in parallel with the pilot project, before commencing with commercial CCS. The study also recommends undertaking comprehensive impact assessments of potential CCS pilots with the participation of different stakeholders, particularly local stakeholders. Local governments and communities must also be invited as stakeholders in the CCS development process, starting from the initial preparation phase and continuing through project construction, operation, and post-operation.

9.8 An Enabling Environment Is Required for Carbon Capture and Storage Development

This study clearly points out that the presence of techno-economic possibilities alone without secure, actionable progress on the ground will cause CCS implementation to fail. Many disparate elements including technology selection, financing, technical capacity, project leadership, public support, and an enabling regulatory framework must all come together before real progress on CCS can be achieved. The CCS development pathway proposed in this study, therefore, builds progressively from a pilot project toward a demonstration project, and eventually full commercial-scale application. This phased approach to CCS development will enable

- a broad-based coalition of stakeholders on CCS to emerge;
- confidence building in the technology;
- capturing and storing significant amounts of CO_2 in geological reservoirs;
- increased social awareness about CCS and partnerships with communities to build strategies that minimize the local environmental impacts of the project;
- financing structures, business plans, and commercial models to take shape;
- a legal framework to be developed; and
- leadership on CCS to emerge that is institutionally integrated within government, and empowered with budgetary and decision-making authority.

9.9 Carbon Capture and Storage Working Groups Should Be Continued to Advance Development

The development of CCS requires engagement across a wide range of stakeholders. This study recommends the continuation of the CCS working groups that were formed in each of the four countries under this regional technical assistance program. Each working group could provide effective leadership on CCS and help steer the development of a pilot and demonstration project. The study also recommends that the working group should be institutionally integrated within government and empowered with budgetary and decision-making authority so that it can coordinate with the government, policy makers, industry, and the public in managing the CCS development process.

APPENDIX 1

Indonesia Executive Summary

Carbon Capture and Storage Has the Potential to Achieve Deep Emission Reductions

Carbon capture and storage (CCS) is the only technology that can achieve deep reductions in carbon dioxide (CO_2) emissions from fossil fuel use in power plants and other industries. The CCS process involves four key components:

(i) Capture stage: capturing, dehydration, and compression of CO_2 from large stationary emission sources

(ii) Transport stage: transporting CO_2 by tankers, pipeline, or ship to a suitable storage site

(iii) Storage stage: injecting CO_2 deep underground for secure and permanent storage

(iv) Measurement, monitoring, and verification (MMV): for secure and permanent storage underground

Although CCS is yet to be widely deployed, several of its process components are commercially available and proven at a scale required for technology deployment. Globally, 74 large-scale integrated CCS projects are actively under consideration, of which 15 are operational or in advanced stages of development.

Much of the global effort on CCS has been limited to developed countries. For the potential of CCS to be fully realized, CCS must be increasingly deployed across developing Asia, where many new power plants and industrial facilities will be built. CCS is consistent with Indonesia's broader integrated national strategy of balancing economic growth and environmental stewardship.

This Study Offers a Road Map for Carbon Capture and Storage Deployment in Indonesia

The report addresses several existing information gaps on CCS in Indonesia by

(i) creating an inventory of CO_2 emission sources;

(ii) creating an inventory of possible storage sites using secondary data and explicit screening criteria, for geological storage of captured CO_2;

(iii) ranking capture and storage sites and undertaking source-sink matching of capture and storage opportunities;

(iv) identifying a promising CCS pilot project or projects in conjunction with CO_2 enhanced oil recovery (EOR); and

(v) developing an internal network of agencies and personnel (CCS Working Group) with the capacity to carry projects forward.

The study was prepared by a team of national and international experts. It builds on previous Indonesia-specific CCS studies, Understanding CCS Potential in Indonesia, prepared by the Indonesia CCS Working Group in 2009, further examines sources, sinks, and transport options with the intent of offering an actionable and implementable road map for CCS development in Indonesia.

Increasing Energy Use Will Be a Key Driver of Greenhouse Gas Emissions Growth in Indonesia

Indonesia has had a decade of sustained economic prosperity, with annual real gross domestic product (GDP) growing an average of 5% annually between 2000 and 2010. Indonesia's medium-term development plan is pegged to an annual average economic growth rate of 6.5% over 2010–2014.

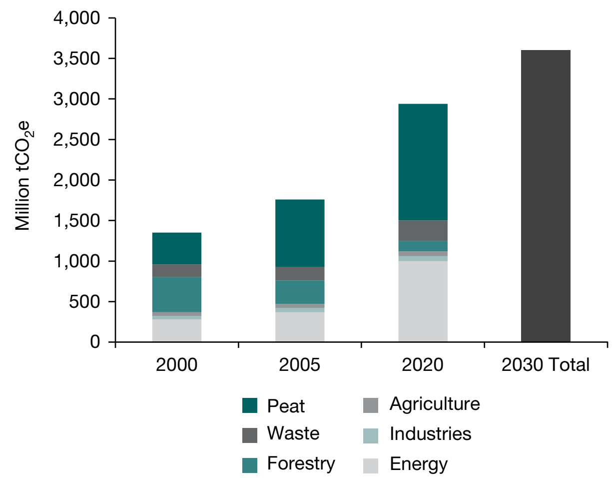
These levels of economic growth will have direct implications on Indonesia's energy sector. Final energy consumption could grow to between 2.5–2.9 million barrels of oil equivalent (mboe) by 2030, implying an annual average growth rate of approximately 5% from current levels (Suryadi 2011). The Indonesian Ministry of Energy and Mineral Resources (MEMR) projects electricity demand to increase more rapidly, from nearly 180 terawatt-hours (TWh) in 2010 to over 700 TWh in 2030.

Indonesia's power generation mix is exceedingly fossil fuel–intensive, accounting for approximately 85% of generation in 2010. The dominance of fossil fuel, reflecting the country's rich abundance of coal resources, is likely to be extended into the future. Coal-fired power generation is projected to experience a fourfold increase in capacity between 2010 and 2030.

Growth of fossil fuel consumption has already had a significant impact on the country's greenhouse gas (GHG) emissions. Although peat and forestry currently represent a sizable part of total emissions, the energy sector will be a key driver of emissions growth. Emissions from the energy sector are projected to grow from 20% of the total emissions in 2000 to 35% by 2020 (Figure A1.1). The expected increase in emissions from the power sector is visibly starker, with a projected sevenfold growth over the next 25 years from 110 megatons (Mt) in 2005 to 750 Mt by 2030.

Indonesia has announced its intention to reduce GHG emissions by 26% by 2020 relative to a business-as-usual case and offered to further reduce emissions by up to 41% with international support. In September 2011, Indonesia adopted the National Action Plan on Climate Change through Presidential Decree 61, 2011. The action plan offers an integrated development strategy aimed at achieving the emission reduction targets announced by the president in 2009. In the energy sector, the plan proposes the increased use of geothermal and other renewables, and contemplates deployment of CCS. CCS could account for 40% of reductions from the power sector.

Figure A1.1 **By 2020, Indonesia's Greenhouse Gas Emissions Will Double from 2000 Levels**



Source: UNFCCC and Republic of Indonesia (2009).

South Sumatra Was Selected as the Focus Region for This Study

South Sumatra is a province located in the southern part of Sumatra Island, Indonesia, with Palembang as the capital. The region is well suited to support this initial assessment on CCS.

A previous study by the Indonesia CCS Working Group in 2009 recommended South Sumatra for demonstrating future CCS projects. Within the South Sumatra Basin are several deep, uneconomic coal resources, mature oil fields with enhanced oil recovery (EOR) opportunities, gas fields, and unidentified saline aquifers with the potential to store relatively large volumes of CO_2. It also has many large stationary sources of CO_2 from power generation and industrial activity that can be captured. The region has existing pipeline infrastructure, which could be leveraged for CCS transport, and a relatively low population density.

Although this study is specific to South Sumatra, many of the insights and lessons will be relevant more broadly across Indonesia. The remainder of this report discusses the data, analysis, and findings based on the specifics of South Sumatra.

South Sumatra Has Approximately 8 Megatons of Annual CO_2 Emissions from Power, Oil Upstream Activities, Oil Refining, Gas Processing, Coal Mining, and Cement and Fertilizer Production

This study assembled a detailed inventory of facility specific information from the sectors listed, except oil upstream activities and coal mining. The data inventory was developed through a questionnaire, requesting information on the plant, operations, and flue gas characteristics. The data collected from the questionnaire were then subjected to validation and assurance. Processes were put in place to ensure confidentiality.

Emissions estimates across the source sectors are listed in Table A1.1.

Following the data inventory of sources, a ranking methodology was developed to assess the suitability of CO_2 capture. The source ranking methodology used 14 criteria that measure the suitability and compatibility with available CO_2 capture technologies.

All criteria are not equally important. Each criterion was given a weight that reflects its relative importance among the set of criteria. The prospective CO_2 sources were then measured against each criterion. They were provided a score, ranging from 0 (least desirable) to 10 (most desirable), indicating how well it measured on that particular criterion.

For each potential source, a composite index value was developed by (i) first, multiplying the score on each criterion with the weight for that criterion (i.e., weighted score); and (ii) second, for each source, the weighted score achieved against each criterion

Table A1.1 **CO_2 Emission Sources**

CO_2 Source	Method	CO_2 (tons/year)
Power plant (multiple sources)	Fuel combustion (IPCC [2006] and Data Survey [2012])	1,786,062
Oil upstream activities* (multiple sources)	Fugitive emission (IPCC [2006])	1,857,410
Petroleum refinery (single source)	Data Survey (2012)	619,527
Natural gas processing facility (single source)	Data Survey (2012)	132,754
Natural gas processing facility** (single source)	Estimation from limited data	390,676
Coal mining (multiple sources)	Fuel combustion (IPCC 2006)	2,879
Cement plant (single source)	Data Survey (2012)	500,760
Fertilizer plant (single source)	Data Survey	2,506,652
Total		**7,796,721**

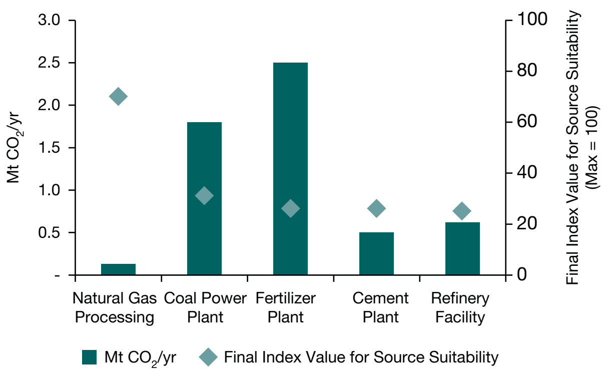
* Includes emissions from flaring and venting from oil field, while emissions from natural gas were not accounted.

** Estimate was made from CO_2 produced in the gas-processing unit not taking into account emissions from fuel consumption. Data source withheld for confidentiality.

is totaled to obtain the total weighted score for that source. This total weighted score was then normalized to 100 and represents the final index value that was used to rank the sources.

The summary source ranking and final index value for source suitability are presented in Figure A1.2. An index value of 100 (maximum value) indicates the highest CO_2 capture suitability.

Figure A1.2 **Source Ranking and Final Index Value for CO_2 Capture Suitability**



Mt CO_2/yr = megaton of carbon dioxide per year.

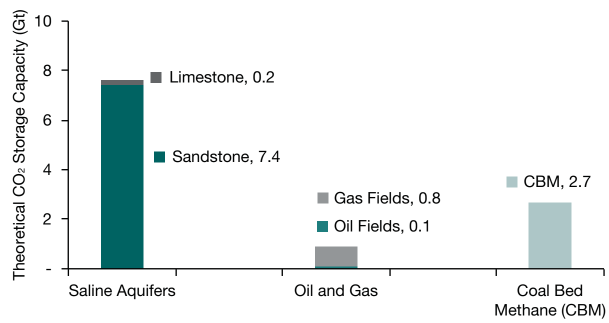
A natural gas–processing facility emerged as the most desirable capture source, with a score more than double that of the second-most attractive source. The facility's high ranking appears to have been the result of its (i) proximity to storage, (ii) high purity CO_2 stream from the exhaust, (iii) relatively new facility, and (iv) sufficient availability of CO_2 to support a pilot project, which can be further increased to meet the requirements for larger demonstration project (500–2,500 tons per day of CO_2) by reducing the temperature of the raw gas feed to the amine absorber to the plant's original design specifications.

The ranking analysis revealed that many of the existing limitations on CO_2 capture from the sources could be overcome in the future with changes to their operations, retrofit, or modernization. This reconfirmed the hypothesis that South Sumatra would continue to have good availability of CO_2 capture sources into the future.

South Sumatra Appears to Have Sufficient Storage Potential to Store the CO_2 Emissions of All Its Point Sources

Preliminary estimates were established for conventional (saline aquifers and oil and gas fields) and unconventional (coal bed methane [CBM] reservoirs) geological storage. The analysis suggests that South Sumatra could have as much as 11 gigatons (Gt) of theoretical CO_2 storage capacity, enough to store the 8 Mt CO_2 of annual stationary source emissions. Figure A1.3 describes the estimated CO_2 storage capacity by category.

Figure A1.3 **Estimated CO_2 Storage Capacity by Category**



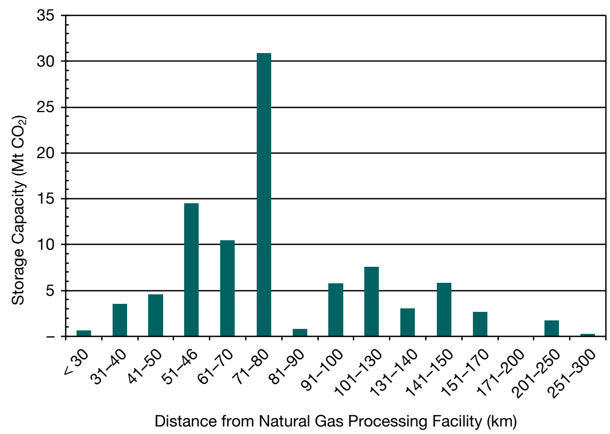
Gt = gigaton.

The vast majority of the theoretical storage capacity is located in saline aquifers. The basins of South Sumatra can be divided into four subbasins: South Palembang, Central Palembang, North Palembang, and Jambi. The sandstone-hosted saline aquifers have a much larger capacity compared to the carbonate saline aquifers. Most of the carbonate aquifers occur in the South Palembang subbasin while the sandstone aquifers, except for North Palembang, increase steadily in volume from the south to north. These estimates reflect resources below 1,000 meters over burden. Although these estimates will improve with better geology and hydrogeology data, the saline aquifers of South Sumatra are large enough to justify further quantification of the region's geological storage potential.

CO_2 storage potential in CBM resources, estimated to be approximately 2.7 Gt, should be considered speculative at this stage. CBM production is still at relative infancy in Indonesia. However, the preliminary estimate suggests a good potential for CO_2 storage worth further consideration if commercial development of CBM is successful.

The CO_2 storage in oil fields is based on the pore space made available through primary recovery and additional recovery due to CO_2-EOR on a reservoir basis. Both primary and tertiary recoveries were used in calculating the total CO_2 storage. This method results in much more storage certainty (i.e., effective storage capacity assessment), compared to the two other methodologies used in the saline aquifers and CBM resources (i.e., a theoretical storage capacity assessment). Most of the oil fields individually have small storage capacities, with only one field exceeding a storage capacity of 10 Mt CO_2. When grouped together by proximity to each other, the largest cumulative capacity was approximately 55 Mt CO_2 in an area within 30 kilometers (km) of each other, out of a total capacity of 92 Mt for the oil fields examined. These oil fields contain 59% of the original oil in place (OOIP) in South Sumatra. Figure A1.4 illustrates the storage capacity from depleted oil fields clustered together by proximity to each other.

Figure A1.4 **Storage Capacity from Depleted Oil Fields**

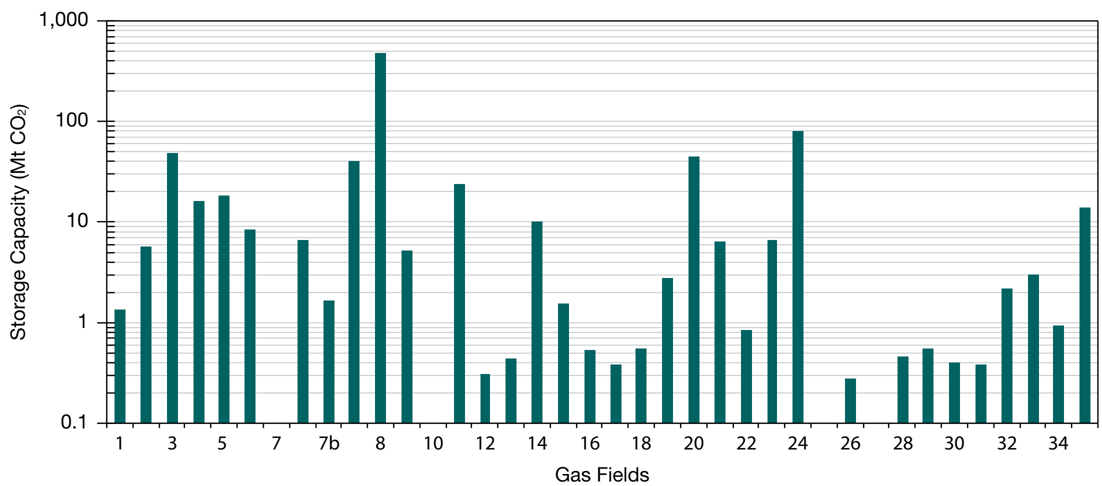


km = kilometer, Mt = megaton.

Gas fields offer 10 times more storage volume than oil fields in South Sumatra. Cumulative storage capacity for all 35 gas fields at depletion was estimated to be 831 Mt CO_2. Ten of the gas fields have capacities greater than 10 Mt, five greater than 40 Mt, and two greater than 80 Mt CO_2. One of the fields (Field No. 8) has a capacity of approximately 500 Mt CO_2—more than five times greater than any of the other gas fields examined. These gas fields contain 47% of the original gas in place (OGIP) in South Sumatra. Figure A1.5 highlights the estimated storage capacity for gas fields.

Recovery factors were used to estimate the storage capacity in gas fields, instead of the cumulative production and reserves data used for oil fields. This

Figure A1.5 **Estimated Storage Capacity for Gas Fields**



method produces a more uncertain estimate than the method used for oil fields.

The H3 Oil Field Achieved the Highest Score on Storage Ranking, Though F21 Is the Suggested Storage for a Pilot

Oil and gas fields offer the best initial storage options. The effective total storage volumes in these fields are sizable, exceeding 90 Mt CO_2 for the fields examined. Availability of production data for the oil fields offers a higher degree of assurance on the storage assessment. Most importantly, the possibility of revenues from EOR makes the oil fields particularly attractive.

Data of the 133 oil and gas fields were analyzed in a ranking assessment to establish which fields were better suited for storage. The ranking methodology used a two-stage approach of qualifying and preferential criteria, as illustrated in Table A1.2. The fields were quantitatively scored using the preferential criteria. The maximum attainable score in each criterion reflects the importance of that criterion relative to the other criteria. For each field, the sum of scores across the criteria represents the final score for storage suitability (maximum attainable score of 100, with additional bonus of 5). The total score for each field establishes the ranking of storage suitability among the fields.

The methodology was adjusted slightly to account for small fields, which might not make the qualifying cut on their own but offer good storage opportunities as satellite fields when in close proximity to larger fields. The results of the ranking analysis are presented in Figure A1.6.

H3 and I2, the two highest-scoring fields, are both oil fields. The high ranking is due to their potential for incremental CO_2-EOR recovery. I2 has the highest injectivity of any oil field, while H3 is the only oil and gas field with a willing partner at the present time. The operator has planned to apply CO_2-EOR in this field. Gas field No. 8 is ranked third with a total storage capacity of 488 Mt CO_2, while the two highest-ranked

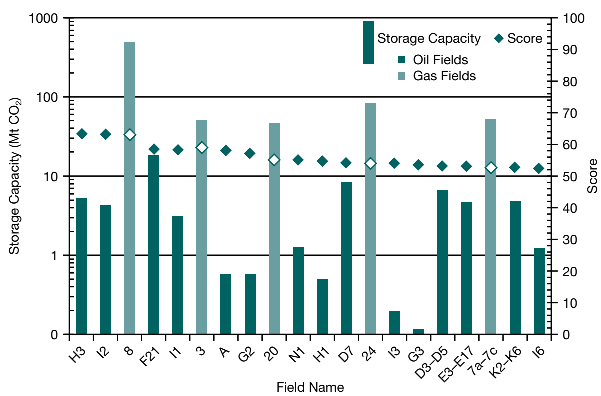
Table A1.2 **Two-Stage Criteria Process to Rank Oil and Gas Fields for CO_2 Storage Suitability**

Qualifying Criteria	
Capacity	Capacity > 10 Mt CO_2, with exceptions for satellite fields
Injectivity	Injection rate > 100 t of CO_2/day/well
Injectivity and capacity	Reservoir > 3 m thick
Confinement: Depth	Depth to top of reservoir > 1,000 m
Confinement: Seal	Seal thickness > 3 m
Confinement: Faults	No active faults
Preferential Criteria	
Capacity	CO_2 storage (21)
Injectivity rate	CO_2 storage/day/well (10)
Injectivity and capacity	Number of existing production/injection wells (10)
Confinement	Seal thickness (16) No. of abandoned wells (4) Contamination of other resources (4)
Economics	Cost recovery (enhanced oil recovery or other offset) (17) Existing infrastructure (4) Monitoring opportunity (4) Availability (depletion date) (5), plus a bonus of 5 if both oil and gas reservoirs are in single field Willingness of operator (5)

m = meter, Mt = metric ton, t = ton.

Note: Number within parenthesis indicates the maximum attainable score in each criterion.

Figure A1.6 **Analysis Ranking of Top 20 Oil and Gas Fields**



oil fields have storage capacities of approximately 5 Mt CO_2 each.

The largest storage capacity in an oil field is for F21 at 18 Mt CO_2 and is ranked fourth. Its storage capacity is three times larger than H3 and I2 and is also closer to the CO_2 source at the natural gas–processing facility. There is a difference in scoring between the H3 and F21 oil fields because the H3 oil field is the only oil or gas field evaluated that had a willing industry partner at the present time.

The Study Recommends Selecting a Source–Sink Match for a Pilot Project

Preliminary work toward a pilot CCS project in South Sumatra is expected to begin in 2012, with detailed design work commencing in 2013. The key initial step will be to identify the source–sink for the pilot project.

A pilot must yield information that will allow predicting the incremental oil production and CO_2 storage expected in a larger demonstration or full commercial operation. While incremental oil in the case of combined CO_2-EOR and CCS project is possible, the essential imperative is to gather information about reservoir performance.

A typical pilot project involves injecting around 50–100 tCO_2/day over several years. A storage demonstration is larger, namely approximately 500–2,700 tCO_2/day and injecting CO_2 over a longer period (10 years). For the pilot, the CO_2 transport could be by truck or boat as the construction of a pipeline will not be justifiable for these low quantities of CO_2. If a demonstration project is subsequently justifiable, a pipeline will be required to transport the CO_2.

Dependency of the source is a key issue. It is not advisable to match a capture pilot to a storage pilot. Technical delays in piloting new capture technologies could make a dependable constant flow of CO_2 for the storage pilot uncertain. To avoid this, the least expensive source of existing CO_2 should be selected. Having sources and sink close to each other is desirable but is not the most critical condition.

For pilots, the source should ideally be pure CO_2 or close to it. The sink should ideally be a large depleted oil or gas reservoir, where in the future the storage costs can be offset by increased production of oil and gas from the reserves. The learning from a storage pilot is not readily transferrable from one field to another. Different geological parameters exist in each field, resulting in different geological models and different reservoir behaviors. Therefore, the study recommends conducting the storage pilot in an oil or gas reservoir that has the possibility of commercial storage potential and matching it with a CO_2 source that offers inexpensive capture.

There are several alternatives for the piloting process. The cost of the pilot would be low if drilling new wells can be avoided. Consequently, the decision should be based on broader considerations, such as planned future infill drilling. If no more drilling is planned, and the existing wells are too far apart, then the pilot could become a short-term CO_2 storage pilot (Phase A) focusing on the injection well with the option for a longer-term multi-well CO_2-EOR pilot (Phase B).

Phase A of the pilot has been conceived as a “long-term well test” or a “micropilot” (Gunter et al. 2008) in the past. The micropilot is designed as a “huff and puff” single-well pilot where data are collected during the injection stage, the soak stage (i.e., shut-in), and the production stage from a single well to measure the reservoir response to injected CO_2. The data history is matched with a reservoir simulator, which is then used to predict the long-term response of the reservoir to CO_2 flooding and storage.

Phase B pilot is intended to be a multi-well CO_2-EOR pilot, potentially in a five-spot arrangement with either four injection wells and a central production well, or four production wells and a central injection well. The pilot would run until the expected response for the predicted enhanced recovery is seen at the production wells, followed by an injection-only storage stage then a shut-in stage. The information from the pilot will determine whether a large demonstration is warranted both technically and economically.

For a Pilot Carbon Capture and Storage Project, a Gas-Processing Plant, Matched with a Storage Site in a Nearby Oil Field, Appears to Be the Best Option

Of the CO_2 sources evaluated, a gas-processing plant was ranked first, followed by a coal-fired power plant. The fertilizer plant was ranked third followed by the cement plant, and finally the refinery. The study did not evaluate sources for which data were not available. For most of the other gas-processing plants, except for the one evaluated, data were not available and could not be assessed. However, these sources should not be neglected in future updates to the analysis.

The gas-processing plant is an attractive CO_2 source for a pilot. It can supply 0.15 megatons of CO_2 per year, which is barely enough for a commercial EOR operation and more than enough for a pilot CO_2 storage project with a typical injection of rate 50–100 tCO_2/d. Some of the other sources discussed have to be identified as the primary source if this CCS project is to be scaled up to a commercial storage operation of at least 1 Mt CO_2 stored annually. Fortunately, other emission sources are within 150 km of the gas-processing plant.

The most attractive oil fields (H3, I2, F21, and I1) are 70–100 km from the gas-processing plant, and are a similar distance from other gas-processing plants in the central part of the South Sumatra Basin and within 150 km of other larger CO_2 sources. All the large gas fields, except field No. 7c, with storage capacities individually exceeding 40 Mt CO_2, lie between 150–200 km north of the gas-processing plant in the central part of the South Sumatra Basin and within 50 km of other gas-processing plants. The other large gas field No. 7c lies within 60 km of the gas-processing plant and is close to oil field F21.

The most attractive storage pilot in the South Sumatra Basin would be in an oil reservoir where the commercial opportunity for CO_2-EOR exists, and which therefore could subsequently transition to storage. Field H3 achieved the highest score for storage suitability because it was the only oil or gas field with a willing industrial partner. If F21 had a willing partner, it could have been ranked more favorably than H3 since it is closer to all the major CO_2 sources relative to H3 and has a larger storage capacity.

If storage is the only consideration, then the gas reservoirs score higher than the oil reservoirs. The largest gas reservoirs (each with storage capacities exceeding 40 Mt CO_2) occur in the central part of the South Sumatra Basin, within 150 km of the larger industrial CO_2 sources. The gas-processing plant could serve as source for these storage sites with a trucking distance between 150 km and 200 km for CO_2. Gas field No. 7c, with a trucking distance of 60 km from the gas-processing plant, would be more attractive due to the smaller distance between sink and source.

Carbon Capture and Storage Adds \$28/ton of CO_2 Captured to the Levelized Cost of Natural Gas Processing without Enhanced Oil Recovery (EOR) and \$22/ton of CO_2 Captured with EOR

The economic analysis evaluated an existing onshore natural gas–processing facility that is separating and subsequently venting at atmospheric pressure a stream of pure, water-saturated CO_2 to reduce CO_2 levels in the gas that is sold. The cost of CO_2 separation (capture) from natural gas is borne by the gas producer as part of normal operations. Such a plant would require only CO_2 dehydration/compression equipment to produce a stream of pure dry CO_2 at supercritical conditions and piping suitable for transport and storage or use for EOR. In the absence of EOR, the costs of CO_2 storage must be borne by the natural gas–processing facility.

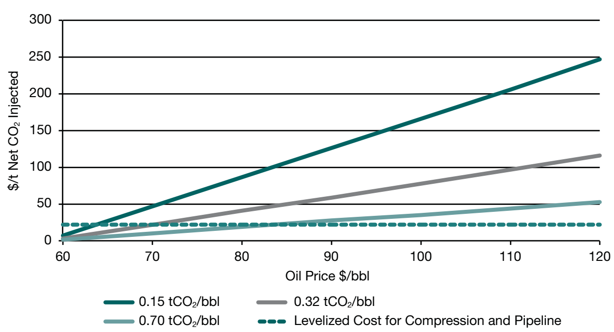
The compression and dehydration cost assumptions were sourced from a 2011 study by the Global

CCS Institute (2011a); EOR cost assumptions were from the United States National Energy Technology Laboratory (NETL 2008). The pipeline and storage cost assumptions were sourced from another report (Alstom 2011). For this illustrative analysis, a nominal gas-processing case of 1 Mt/yr CO_2 captured was selected.

The total incremental capital costs inclusive of allowance for funds during construction and including storage costs were approximately $167 million. Incremental operating costs were approximately $12 million per year. The weighted average cost of capital (WACC), reflecting the financing parameters, was assumed to be 8.64%.

Figure A1.7 illustrates the levelized cost of capture with EOR, along with the implied CO_2 credit price and related oil prices.

Figure A1.7 **Levelized Cost of CO_2 Capture with Enhanced Oil Recovery**



bbl = barrel, t = ton.

The levelized cost for a natural gas–processing facility capturing CO_2 without EOR (i.e., when storage costs are included) is $28/t of CO_2 captured. This levelized cost is composed of compressor plus dryer of $11/t$CO_2$ captured, pipeline of $11/t$CO_2$ captured, and injection wells of $6/t$CO_2$ captured. With EOR, the levelized cost drops to $22/t$CO_2$ captured since the storage costs are borne by the EOR operator. This implied credit price translates into an oil price of $70/bbl (at a CO_2 net utilization of 0.32 tCO_2/bbl). At higher oil prices, the natural gas–processing plant would be more than able to offset its CCS-related costs through EOR revenues.

Several Financing Options Must Be Explored to Offset Incremental Carbon Capture and Storage Costs

A wide variety of funding sources, comprising government, multilateral, and bilateral development assistance, multilateral, and bilateral climate-specific funds, and the private sector, could be available to offset the incremental costs of CCS.

Domestically, the Low-Emission Development Financing Facility (LEDFF) could be an option. LEDFF seeks to coordinate private funding by matching it with large-scale capital requirements. CCS investments could be supported by LEDFF activities. The Indonesian Climate Change Trust Fund (ICCTF) offers another source for financing support for CCS. Established in 2009, ICCTF provides access to finance from international sources for climate-related adaptation and mitigation expenditures. One possible financing structure could be to leverage ICCTF to generate supplemental funding required for CCS beyond the EOR revenues. Additionally, tax incentives, such as the Incentive Package 1992 and 1994, which provide an investment credit for EOR could be extended to cover CCS investments.

Existing Laws Could Be Expanded to Provide the Legal and Regulatory Framework for Carbon Capture and Storage

There are no existing laws in Indonesia that are specific to CCS. The wider deployment of CCS will require a legal and regulatory framework that, at a minimum, provides the following: (i) classifies CO_2; (ii) defines surface and subsurface rights for CCS; (iii) specifies long-term stewardship and liability for CO_2; and (iv) develops regulations on environmental protection (including impact assessments), transport, health and safety, public participation, and foreign investment.

In many instances, the legal requirements for CCS could be developed by expanding or adapting existing regulations to cover CCS. One way of approaching this may be to initiate a law and policy reform process sponsored by Ministry of Energy and Mineral Resources, Ministry of Environment, Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas

Bumi (Indonesian Oil and Gas Upstream Regulatory Body), and Badan Pengatur Hilir Minyak dan Gas Bumi (Indonesian Executive Agency for Downstream Oil and Gas Activity), along with other relevant regulatory bodies.

One of the key aspects of readying the legal and regulatory framework for CCS will be to review concession agreements on grant or retention of pore space. This could be used to develop the framework for pore space ownership for inclusion in future concession agreements.

An Effective Communication and Engagement Strategy Must Parallel Carbon Capture and Storage Deployment

Public perceptions are often the most understated challenge to development and deployment of new technology. There is little public awareness about CCS. An effective communication strategy would ensure that there is an awareness-building campaign about CCS technology prior to deployment or even a pilot. In addition, the deployment of CCS in Indonesia must be accompanied by a comprehensive impact assessment. These studies should have broad participation, particularly of local stakeholders.

Local governments and communities should be invited as stakeholders to the CCS development process starting from the preparation phase, and continuing through construction, operation, and into post-operations.

Report Proposes a 7-Year Road Map for the Pilot Project That Builds the Pathway for a Larger Carbon Capture and Storage Deployment in 20 Years

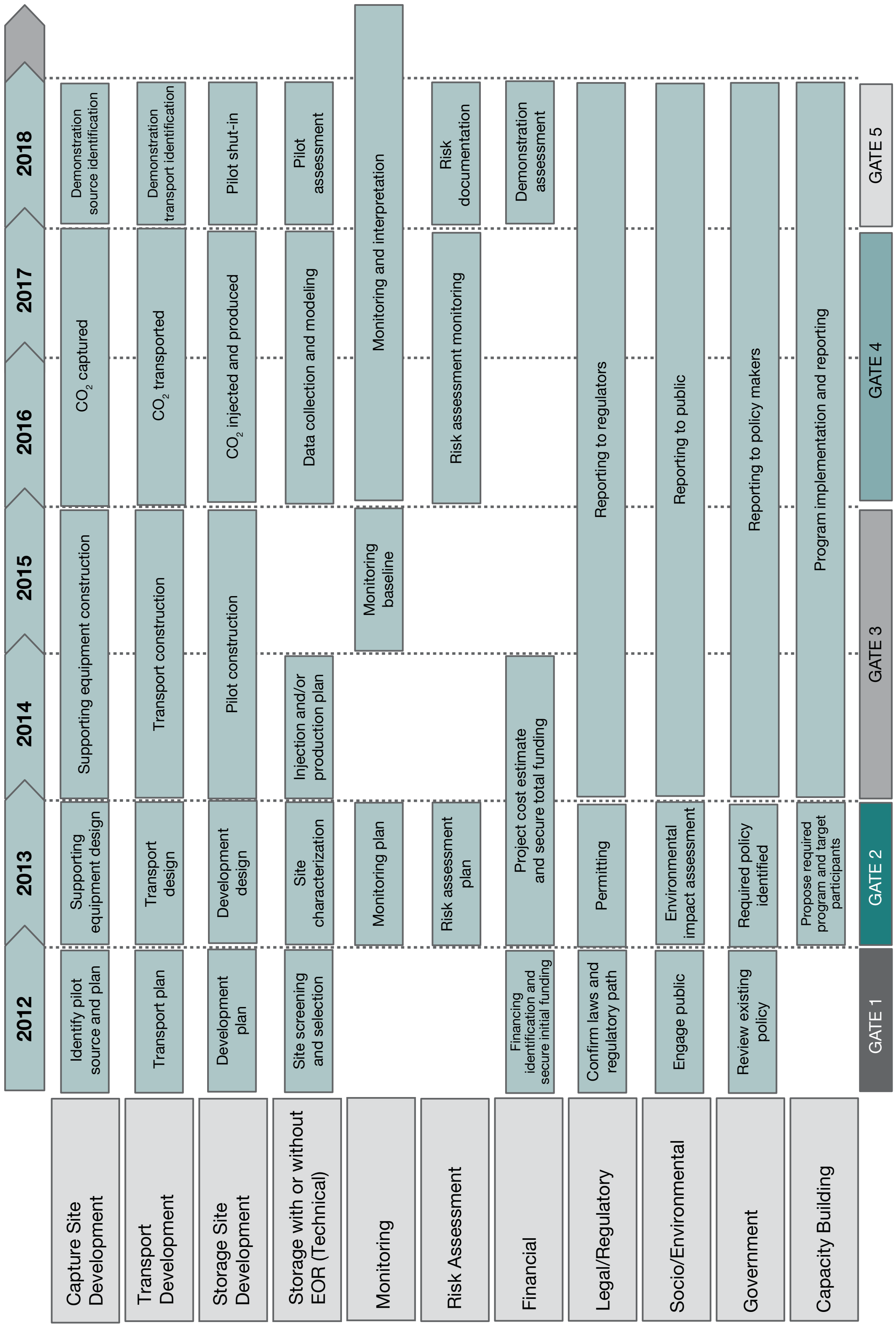
The developmental pathway from a pilot to commercial application must evolve by building on the learning, data, and experiences gained at each subsequent step. The proposed road map is modeled on a three-stage approach to commercial development, as outlined in Figure A1.8.

The proposed road map for the pilot is illustrated in Figure A1.9. It is an integrated road map that identifies key action items for the CCS pilot project and provides guideposts on schedule and activities on a year-to-year basis.

Figure A1.8 **Three-Stage Approach to Carbon Capture and Storage Application**

STAGE 1	**PILOT** • 50–100 tons per day of CO_2 over several years • Knowledge of reservoir performance to support financing and designing of demonstration project
STAGE 2	**DEMONSTRATION** • Larger quantities of CO_2 injected into many wells continuously over many years • 500–2,700 tons per day or more of CO_2 injected over 10 years • Confirmation of long-term successful CO_2 storage to support financing and construction of at least one full-scale commercial operation
STAGE 3	**COMMERCIAL** • Very large quantities of CO_2 captured from one or more sources and injected into one or more locations for a very long time period • 2,700–30,000 tons per day CO_2 captured and injected over 20 years • Capture and store sufficient quantities of CO_2 to substantially reduce CO_2 emissions

Figure A1.9 **Road Map for Pilot Extends over 7 Years with Five Gates**



EOR = enhanced oil recovery.

The road map is built on five stage gates for proceeding through successive tasks. The principal tasks are capture site development, transport development, storage site development, technical planning for storage with or without EOR, monitoring, risk assessment, financial, legal/regulatory, socioeconomic/environmental, government engagement, and capacity building. Some of the initial tasks preceding Gate 1 have already been completed in 2012 under this regional technical assistance. Most of the tasks have yet to be completed.

The stage gates for the pilot to move from one stage to another are the following:

Gate 1: Pilot CO_2 source and storage site have been identified and the owners/operators are supportive.

Gate 2: Pilot funding has been secured and permitting has been completed.

Gate 3: The construction of the pilot has been completed.

Gate 4: Injection of 50–100 tCO_2/day has been successful.

Gate 5: Case for a storage demonstration is approved based on a successful pilot assessment.

CCS development during the pilot, demonstration, and commercial stages are expected to use the same storage site as increasing quantities of CO_2 are injected. The CO_2 source is expected to change, as larger supplies of CO_2 are required.

The results of the pilot operation should help confirm that the selected reservoir(s) are capable of sustaining a longer-term, large-scale CO_2 injection program. In the case of potential EOR, the pilot operation should predict the amount of incremental oil that can be recovered from a commercial operation in the same field and address the timing when it transitions to a commercial storage operation. The intermediate demonstration phase is used to confirm the predictions made based on the pilot phase.

During the pilot phase, the commercial supply source for CO_2 needs to be quantified and its costs understood. All aspects of CO_2 capture, transportation, and injection must be designed. A business plan needs to be developed, including identifying the funding sources. Clear regulations will be required. An impact assessment with extensive public engagement must also be conducted.

Commercial projects will only follow if a successful demonstration plant has been operating for several years. It will need detailed design, cost estimate, a well-evolved business plan, and a robust impact assessment. Many of these components will be influenced by learning and experiences from the pilot and demonstration projects. Continuity between the different stages of development is essential to evolving a CCS development pathway that continues to build on past achievements.

APPENDIX 2

Philippines Executive Summary

Climate change, which is largely the result of anthropogenic greenhouse gas (GHG) emissions, is a global issue and requires global solutions. Carbon dioxide (CO_2) in the atmosphere is one of the main causes of global warming. In Southeast Asia, average temperatures have increased 0.1°C–0.3°C per decade over the last 50 years, while in the Philippines the temperature has increased by 0.14°C per decade since 1971.

Agencies and institutions worldwide agree that to restrict global temperature increases to below 2°C, a whole range of technology measures is required to reduce global CO_2 emissions by more than half and maintain CO_2 concentration levels within 450 parts per million (ppm) by 2050. These technology measures include energy efficiency and conservation, renewable energy, and carbon capture and storage (CCS). For example, under the 2009 Business-as-Usual (BAU) scenario of the Asian Development Bank (ADB), in 2050, GHG mitigation through CCS could become feasible[1] with reduction potential of up to 22% of the total emissions in four countries: Indonesia, the Philippines, Thailand, and Viet Nam.

In the short term, developed countries must lead the CCS effort, but for the true potential of this technology to be realized, it must spread rapidly in developing Asia, where many power plants and industrial facilities are being built. ADB's Energy Policy describes CCS as a clean technology approach to be promoted as it becomes technically feasible and economically viable. Accordingly, ADB conceptualized this regional technical assistance for "Determining the Potential for Carbon Capture and Storage in Southeast Asia" with government agencies in Indonesia, the Philippines, Thailand, and Viet Nam. It builds on ongoing activities in CCS being supported by ADB in Asia and helps expand the geographical scope of ADB's support for CCS as a way of mitigating carbon emissions.

Country Background: The Philippines is the second-largest archipelago in the world. It is situated in Southeast Asia and has a diverse population of about 94 million. It consists of three main groups of islands: Luzon, Visayas, and Mindanao.

1. **Economy.** The Philippine economy grew on average by 4.5% annually from 2000 to 2009, which was at par with the economic performance of its neighbors, except Viet Nam, which grew by 7.0% in that period. In 2010, the country's gross domestic product (GDP) expanded by 7.6%, the highest in 24 years. The unreliability and high cost of electricity is the biggest threat to the economic growth of the country. To support future economic growth, developing the energy sector is vital. The government is pursuing policy thrusts and programs in support of national economic development, as embodied in the Philippine Energy Plan (PEP). The PEP aims to (i) ensure energy security, (ii) achieve optimal energy pricing, and (iii) develop a sustainable energy system.

2. **Government Strategy for a Low-Carbon Future.** In an era where green energy and alternative fuels are bywords in global development, the Department of Energy (DOE) is taking the country's long-term best interest by adopting the use of clean, green, and sustainable sources of energy in its energy security strategy. In this regard, the government is implementing low-carbon future programs such as (i) the Alternative Fuels Program under the Biofuels Act of 2006, to promote the use of biofuels; (ii) the Fueling

[1] With the carbon price projected to be above $80/t$CO_2$.

Sustainable Transport Program, to synchronize and integrate into one comprehensive program to promote the utilization of alternative fuels for public transport such as compressed natural gas (CNG) and liquefied petroleum gas (LPG), as well as new technologies such as e-vehicles (i.e., electric buses, cars, jeepneys, and tricycles); (iii) the Natural Gas Infrastructure Development Program, to support natural gas as fuel for the future; (iv) the National Renewable Energy Program under the Renewable Energy Law, to increase the use of green fuels such as geothermal, hydro, wind, biomass, and solar; and (v) the Philippine Energy Efficiency Project, to start a comprehensive energy efficiency program and identify a range of pilot projects on energy efficiency and conservation.

3. **Primary Energy Supply and Demand.** Oil comprised 35% of the primary energy supply in 2010, while coal, natural gas, and renewable energy contributed 17.2%, 7.4%, and 39%, respectively. Total energy demand grew at an average of 0.42% or from 35 million metric tons of oil equivalent (Mtoe) to 41 Mtoe for the period 2000–2010, with projections to increase to 48–52 Mtoe by 2030.

4. **Indigenous Energy Resources.** Based on data available as of July 2012, the Philippines is endowed with relatively modest reserves of crude oil at about 168 million barrels (MB), 109 MB of condensates, 3.8 trillion cubic feet of natural gas, and about 420 million metric tons of coal. Its estimated renewable energy potential could be as high as 109,000 megawatts (MW).

5. **Electricity Supply and Demand.** The Philippines' total installed generation capacity in 2010 was 16,359 MW while the electricity generated was 67,742 gigawatt-hours (GWh) with the corresponding CO_2 emissions at 31 megatons CO_2 equivalent (Mt CO_2e). The average carbon intensity of the whole generation fleet in 2010 was estimated at 480 kilograms (kg) of CO_2 per megawatt-hour (MWh). Power generation grew by an average of 4.6% per year over the period 2000–2010. The dependable capacity was recorded at 13,902 MW or 85% of the total installed capacity, with the largest coming from coal (30.53%), hydro (21.73%), and natural gas (19.83%).

6. **Power Development Plan (PDP).** Electricity sales are projected to increase from 55,266 GWh in 2010 to 149,067 GWh by 2030. These are translated to peak demand of about 24,534 MW by 2030. New power plant capacities totaling 14.4 gigawatts (GW) were identified in the PDP to meet the demand and reserve requirements for electrical power. Power demand would still be highest in the main island of Luzon grid at 10.5 GW or 72.6% of the total. About 50% of the planned capacity addition in Luzon will be located in the CALABARZON region.[2]

7. **Greenhouse Gas Emissions Profile.** The energy sector generated 68.91 Mt CO_2e of emissions in 2008 which is a 38% increase from the 50 Mt CO_2e emissions in 1994. Electricity generation accounts for 39.9% of the total emissions, followed by transport at 35.6%, industry (17.0%) and the remaining 7.5% from the commercial, agricultural, and residential sectors combined. Combustion of oil accounted for 36.59 Mt CO_2e/yr, coal for 24.85 Mt CO_2e/yr, while use of natural gas contributed 7.47 Mt CO_2e/yr. These figures represent 53.1%, 36.1%, and 10.8%, respectively, of the country's total annual CO_2 emissions in 2008.

8. **Projected Greenhouse Gas Emissions.** Based on the planned generation capacity installations for 2012–2030, the total GHG emissions from the electricity generation sector would increase from 33 Mt in 2010 to at least 90 Mt in 2030. Accordingly, the average carbon intensity of 0.45 kg CO_2/kWh in 2009 would increase to about 0.54 kg CO_2/kWh in 2030.

Carbon Capture: There are no carbon capture projects in industrial processes or in operating power generation facilities in the Philippines primarily due to the many challenges surrounding the use of CCS technology such as technical, cost-competitiveness, environmental and public health risks, and the

[2] CALABARZON is the acronym for the five provinces in the immediate vicinity of the National Capital Region (NCR) or Metro Manila, namely, CAvite, LAguna, BAtangas, Rizal and QueZON..

absence of policies mandating reductions in carbon emissions or specific laws for the purpose.

1. **Applicable Carbon Capture System:** Post-combustion capture, i.e., CCS retrofit or use in new plants, was considered the most applicable system because it involves very minimal changes in the combustion process of existing or new power plant facilities. A precombustion capture system, on the other hand, is recommended to be adapted to new power plants (greenfield power projects) that are planned for construction starting in 2020. New or retrofit for oxyfuel combustion was not considered, as the technology has not reached maturity.

2. **Carbon Emission Sources:** The study focused on the evaluation of CO_2 capture potential of major stationary CO_2 sources in the CALABARZON region.

   CO_2 emission sources identified in CALABARZON are (i) the Shallow Water Platform natural gas–processing facility in offshore Palawan, and (ii) three coal-fired power plants, three gas-fired power plants, three cement plants, and an oil refinery. These candidate capture plants were then assessed for capture readiness using predetermined qualifying criteria for mandatory assessment and preferential criteria for the next level assessment.

3. **Assessment of Emission Sources.** The CO_2 sources from the industry sector, such as the shallow water natural gas–processing platform, the oil refinery, and the three cement manufacturing plants, did not meet the mandatory criteria and thus were eliminated outright as candidate emission sources. On the other hand, only four power plants, a coal-fired power plant (500 MW), and the three natural gas combined-cycle (NGCC) power plants (2,700 MW in total) satisfied the mandatory criteria.

4. **Carbon Capture Plants.** The result of the scoring and ranking process used in the next level assessment shows that a NGCC plant (3.1 Mt CO_2/yr) was ranked the most viable candidate for CCS, followed by the other two NGCC (2.8 Mt CO_2/yr and 1.4 Mt CO_2/yr), and the coal plant (3.1 Mt CO_2/yr) in descending order.

   The four candidate power plants, however, should be retrofitted to adopt CCS within the next 10 years (before 2020), at which point their remaining life would still be at least 20 years. Among other things, given that the current state of CCS technology is not mature and directive is lacking from the government on CCS, it is very unlikely that the four candidate carbon capture plants would be CCS-ready by 2020.

   The study team identified and assessed possible coal- and gas-fired capture plants from a list of planned capacity additions for 2012–2030. Of the 22 coal- and gas-fired power plant projects totaling 6,455 megawatt electrical, only one 550 MW natural gas power plant, with estimated CO_2 emissions of 1.5 Mt/yr could be considered for CCS by year 2020.

Carbon Storage: The different geologic formations that were considered for use as CO_2 storage facilities are sedimentary basins (conventional storage)—oil and gas fields, saline aquifers, and unconventional storage sites such as geothermal fields, ophiolites, coal beds, and shales.

1. **Oil and Gas Fields:** The cumulative storage capacity of the 14 oil reservoirs that were assessed is 35 Mt CO_2, the largest being of 20 Mt CO_2 and 3 Mt CO_2. On the other hand, the cumulative storage capacity of the five gas fields covered in this study is 287 Mt CO_2. An offshore gas field has the largest storage capacity at 251 Mt CO_2 followed by another gas field at 36 Mt CO_2.

   The large offshore gas field was ranked first among the candidate geologic sites for carbon storage, followed by the smaller oil and gas fields. The large offshore gas field, however, is still producing gas and its petroleum resources are not expected to be depleted until 2030 or 2024 at the earliest. The availability of the other fields as storage sites, on the other hand, remains uncertain.

2. **Saline Aquifers:** Among the 16 sedimentary basins, only two—the Cagayan and Central Luzon basins—have sufficient data for initial CO_2 storage screening. The Central Luzon Basin lies within 50 kilometers (km) of CALABARZON and is relatively clear of faults; thus, it was evaluated first as a possible storage site. The theoretical storage

capacity of 23 gigatons (Gt) CO_2 for deep saline aquifers in the two basins could hold the total CO_2 emissions from CALABARZON for more than 100 years.

3. **Geothermal Fields:** Geothermal fields and prospects would need further study or pilot testing for CCS especially in areas that are within a reasonable distance of identified CO_2 sources. Located in CALABARZON are the Mabini geothermal prospect in Mabini, Batangas, the producing Mak-Ban geothermal field in Laguna–Quezon, and the unproductive geothermal wells in the Mt. Natib geothermal prospect in Bataan, about 80 km east of Metro Manila.

4. **Ophiolites:** The Zambales Ophiolite, located west of the Central Luzon Basin, is the most promising among the ophiolite bodies for storage. However, substantial research on permeability and sealing is needed to assess their potential for carbon storage.

5. **Coal Beds and Shales:** A study on an enhanced production process similar to enhanced oil recovery (EOR) called enhanced coal bed methane (ECBM) recovery in coal seams is being investigated by the DOE. Unfortunately, areas where the project is implemented are located far from CO_2 emission sources in CALABARZON. Therefore, none of the coal mines were considered for carbon storage in this study.

Source–Sink Matching: The large offshore gas field can accommodate an annual CO_2 emission of 10 Mt/yr from the four candidate capture plants in CALABARZON for at least 20 years or 3.32 Mt/yr of CO_2 emissions from the most viable NGCC plant for at least 80 years. Given, however, the 300 km distance radius between the emission sources in CALABARZON and the potential storage sites that are all located in Northwest Palawan, the cost of transporting CO_2 would need some consideration if a new high-pressure pipeline dedicated to CCS is to be built.

CO_2 Transport: In the absence of other viable storage options in the near and long term, it is logical and practical to use the existing 504 km natural gas pipeline for transporting CO_2 from CALABARZON to the storage site. This would also effectively make the large offshore gas field "sit" near CALABARZON as most of emission sources would be within 20 km of the associated onshore gas plant (OGP). The OGP can therefore serve as the "staging area" or CO_2 hub for collection and transportation of captured CO_2 from CALABARZON to the offshore storage site in the Northwest Palawan gas field. It could also be used for pipeline sharing of other capture plants to reach economies of scale for carbon transport of at least 10 Mt CO_2/yr.

Economics of Carbon Capture and Storage: The study illustratively evaluated the cost impacts of including CCS on a supercritical pulverized coal (SCPC) power plant and a natural gas combined-cycle (NGCC) power plant. CCS incrementally adds $2,806/kW to the total capital costs of a SCPC plant, resulting in a 74% ($64/kWh) increase in the levelized cost of electricity (LCOE). Similarly, CCS incrementally adds $1,444/kW to the total capital costs of a NGCC plant, resulting in a 47% ($31/MWh) increase in the LCOE. The resulting abatement costs for SCPC and NGCC plants with CCS are $93/t and $97/t$CO_2$ avoided. The estimated long-term power tariff of $95/MWh could approximately cover the LCOE of a NGCC plant with CCS of $97/MWh. However, the NGCC plant with CCS may still need to be compensated for the loss of profit margins.

Policy and Regulatory Framework: As with other countries in the region, the Philippines already has several laws and regulations that could potentially be used to regulate CCS projects. The country's various energy laws (i.e., oil and gas, coal, geothermal) could provide models for specific elements of a CCS regulatory framework, such as those for exploration permits and service contracts for energy development. Environmental laws could cover provisions for ongoing liability for negligence or intentional misconduct in carrying out a CCS project. Nevertheless, specific provisions of law are needed to address, among others, (i) ownership and long-term stewardship of injected CO_2 on state land, (ii) containment structures, and (iii) monitoring, measurement, and verification requirements.

Public Perception and Social Acceptance: While high cost is perceived as a significant barrier to developing CCS, its public acceptance concern would be the affordability of the electricity when CCS is installed. Public awareness of CCS is relatively low as compared to awareness of climate change. Whereas public participation is required under existing environmental impact assessment and energy development projects, developing a regulatory structure to manage the risks of CCS and to establish channels for the public to participate and develop confidence in the technology could increase the social acceptability of CCS.

The government needs to demonstrate its commitment to pursuing CCS through public statements, funding of CCS activities at a low but effective level, institution of a basic "capture ready" policy, and the initiation of public engagement on CCS.

Piloting to Commercial Projects: For the Philippines, the selection of the large offshore gas field as the best and most practicable CCS site means that piloting should be focused on the technical details regarding how to reverse the circulation of flow from the oil and gas production to the storage site when CO_2 will now be the fluid running inside the pipelines. Pilot injection may have to be performed in one or two of the wells while one of the wells may be used for observation. Assessment should be made to determine which of the platform facilities or equipment can be used for the pilot test.

Pilot testing should also be conducted on unconventional storage options like ophiolites, geothermal sites, and coal beds and shales to benefit CO_2 generators that have no access to conventional CCS storage options or from a need to access storage before that of the oil and gas fields are available. These pilot tests would (i) prove the hybrid CCS concept of linking small, nonproducing geothermal fields (e.g., Mabini, Batangas, or Mt. Natib, Bataan) with CO_2 emissions from existing power plants and extracting energy from these geothermal fields based on the utilization of the injected CO_2; and (ii) assess the permeability of ophiolites (e.g., Zambales ophiolites) which controls CO_2 injectivity and storage in ophiolites.

In conclusion, there are limited opportunities for large-scale deployment of CCS in the country before 2024. One option may be to focus the pilot on the technical details of reversing the circulation from the onshore gas platform to the large gas field carbon storage site. Another approach may be to undertake early work to characterize and pilot test unconventional storage options (e.g., geothermal fields and ophiolites) for CO_2 generators that may lead to alternative opportunities for storing CO_2 from CALABARZON in geological formations that are much closer to the CO_2 sources and are not able to easily access conventional CCS storage.

APPENDIX 3

Thailand Executive Summary

Carbon Capture and Storage Has the Potential of Achieving Deep Emission Reductions

Carbon capture and storage (CCS) is the only technology that can achieve deep reductions in carbon dioxide (CO_2) emissions from fossil fuel use in power plants and other industries. The CCS process involves four key components:

(i) Capture stage: capturing, dehydration, and compression of CO_2 from large stationary emission sources

(ii) Transport stage: transporting CO_2 by tankers, pipeline, or ship to a suitable storage site

(iii) Storage stage: injecting CO_2 deep underground for secure and permanent storage

(iv) Measurement, monitoring, and verification (MMV) for secure and permanent storage underground

Although CCS is yet to be widely deployed, several of its process components are commercially available and proven at a scale required for technology deployment. Globally, 74 large-scale integrated CCS projects are actively under consideration, of which 15 projects are operational or in advanced stages of development.

Much of the global effort on CCS has been limited to developed countries. For the potential of CCS to be fully realized, CCS must be increasingly deployed across developing Asia, where many new power plants and industrial facilities will be built.

This Study Offers a Road Map for Deployment of Carbon Capture and Storage in Thailand

The report addresses several existing information gaps on CCS in Thailand by

(i) creating an inventory of CO_2 emission sources;

(ii) creating an inventory of possible storage sites using secondary data and explicit screening criteria for geological storage of captured CO_2;

(iii) ranking capture and storage sites and undertaking source–sink matching of capture and storage opportunities;

(iv) identifying a promising CCS pilot and larger-scale projects in conjunction with CO_2-enhanced oil recovery (EOR); and

(v) developing an internal network of agencies and personnel (CCS Working Group) with the capacity to carry projects forward.

The study was prepared by a team of national and international experts. It builds on previous CCS studies in the region and further examines sources, sinks, and transport options with the intent of offering an actionable and implementable road map that could guide CCS development in Thailand.

Carbon Capture and Storage Could Support Thailand's Move toward a Restructured Economy that Balances Economic Growth and Sustainability

Thailand has been one of the success stories of economic growth and development. In July 2011, the World Bank upgraded Thailand to an upper-middle-income country from a lower-middle-income one, marking a significant milestone in the country's remarkable growth story. Thailand's economy grew by an annual average real growth rate of 4% in the years between 2000 and 2010. Following the recent economic downturn and the severe flooding in 2011, the country is slowly returning to strong growth. The International Monetary Fund (IMF) projects that Thailand will return to 5% growth by 2015 (IMF 2012).

Energy use in Thailand has broadly tracked economic growth, averaging 4.3% per year between 2000 and 2010. Energy demand is likely to continue growing at these levels, particularly as the economy bounces backs. Fossil fuels account for a large share of Thailand's energy use, though the country is seeking to expand renewable energy and energy efficiency significantly through several concurrent programs. Imported coal is likely to play a bigger role in the energy mix, particularly in electricity generation where its generation share is likely to grow at the expense of gas.

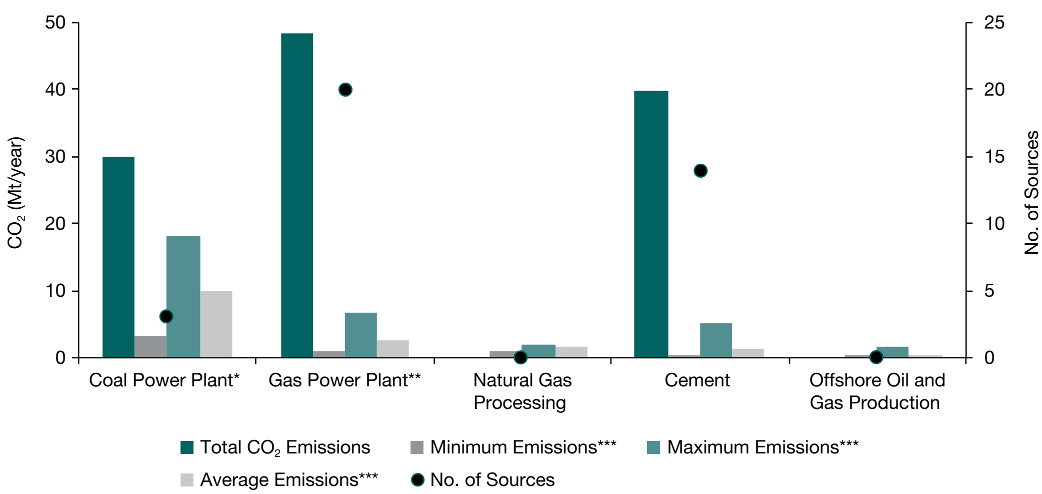
Over the last 5 years, Thailand implemented its National Strategic Plan on Climate Change (2008–2012) focusing on six broad strategic objectives: (i) adaption, (ii) mitigation, (iii) research and development, (iv) awareness, (v) local climate-related capacity building, and (vi) international negotiations. The nation's strategic plan builds on its broader vision for economic and social development that recognizes the need to transition to a restructured economy balancing growth and sustainability. CCS could support this transition effort.

The Study Identified 50 Potential Sources for CO_2 Capture across Four Sectors

In Thailand, power, cement, natural gas processing, and oil and gas production represented the best capture sources. Collectively, these sources produce approximately 120 megatons (Mt) per year. The power sector is the largest emitter; gas- and coal-based power generation account for 35 Mt and 49 Mt per year, respectively. Figure A3.1 describes the distribution of CO_2 emissions potentially available for capture across the sectors.

The largest emission source (lignite power plant) produces 18 Mt CO_2 per year. The second-highest emission source produces less than half that volume. Of the 51 sources, 29 produce more than 1 Mt per year; 21 sources produce more than 2 Mt per year.

Figure A3.1 **CO_2 Emission Sources with Potential for Capture**



Mt = megaton.

* Coal power plant includes one supercritical power plant with emissions of 3 Mt per year, the rest are subcritical coal power plants.

** Gas power plant includes an oil- and gas-based steam thermal plant with emissions of 7 Mt per year.

*** Minimum emissions from a source within the sector; maximum emissions from a source within the sector; average indicates the average emissions across sources within the sector; no. of sources indicates the number of facilities within the category that were represented in the data inventory.

Natural Gas Processing and Power Plants Offer the Best Prospects for Capture

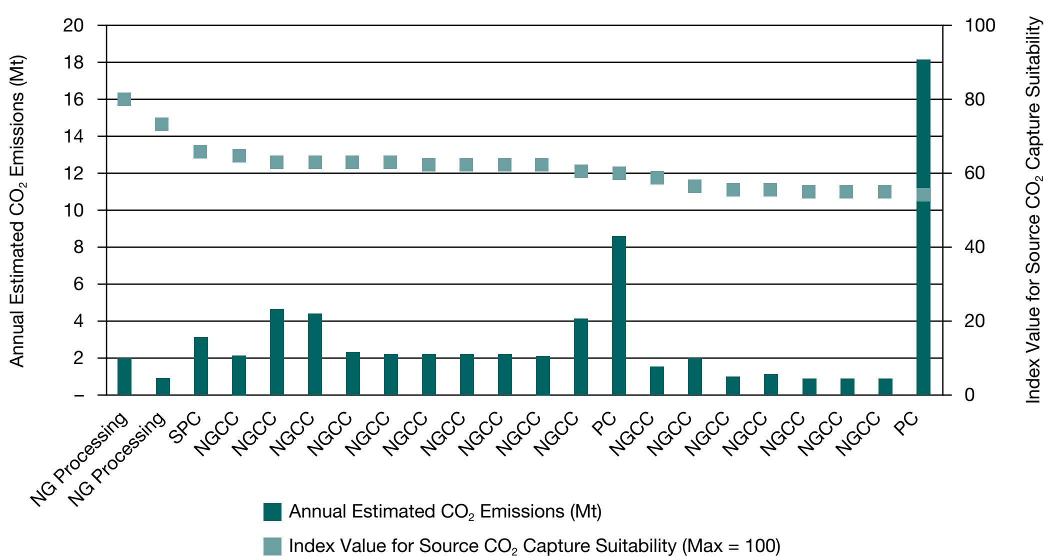
Although Thailand has over 50 emission sources with potential for capture, the study set out to identify the sources that would offer the best capture opportunity for the pilot and demonstration stages. The team developed a methodology to rank sources by suitability for capture. This ranking methodology uses a two-stage approach of qualifying and preferential criteria.

Potential sources undergo further consideration if they meet the qualifying criteria. The qualifying criteria require plants to have more than 20 years of remaining life and have low variability of operation for a steady stream of CO_2. The preferential criteria measure a source's capture suitability over 11 different physical and technical attributes.[1] All the criteria have varying degrees of importance. Each is given a weight that reflects its relative importance among the set of criteria. The prospective CO_2 sources are then measured against each criterion. They are provided a score, ranging from 0 (least desirable) to 10 (most desirable), indicating how well they measured on that particular criterion.

For each potential source, a composite index value is developed by (i) first, multiplying the score on each criterion with the weight for that criterion (i.e., weighted score), and (ii) second, for each source, the weighted score achieved against each of the criteria is totaled to get the total weighted score for that source. This total weighted score is then normalized to 100 and represents the final index value that is used to rank the sources.

Figure A3.2 illustrates the top 22 emission sources along with final index value for CO_2 capture suitability. An index value of 100 (maximum value) indicates the highest CO_2 capture suitability.

Figure A3.2 **Top-Ranked Emission Sources for CO_2 Capture Suitability**



NG = natural gas, NGCC = natural gas combined-cycle, PC = pulverized coal, SPC = supercritical coal power plant.

Note: Number in parenthesis indicates specific unit of the plant.

[1] Preferential criteria include (i) remaining life; (ii) plant operation stability; (iii) CO_2 volume by year; (iv) source stream concentration for each of the following: CO_2, NOx, SOx, O_2, particulate content; (v) trace material; (vi) distance from attractive storage location; (vii) existing infrastructure; (viii) space availability; (ix) supercritical (if coal power plant); (x) willing partner in CCS; and (xi) storage opportunity.

The ranking results underwent several sensitivity tests with small changes in weights and scores. The overall rankings remained unchanged, suggesting that the results were robust and not overly influenced by the subjectivity in the determination of scores or the weights. Most of the 22 top-ranked sources are clustered in the central part of the country; three are located in the south and two dispersed in the north. The two top-ranked sources, the natural gas-processing plants, are located onshore and offer good opportunities for CO_2 capture demonstration. These plants are attractive because (i) they offer high CO_2 emission rates with high CO_2 purity, (ii) they are close to the chosen sinks, and (iii) existing infrastructure (high-pressure gas pipelines connecting the plant to the producing fields) is present.

The source ranking did not include future power plants because information about their location was not available. Between 2012 and 2020, approximately 9 gigawatt (GW)—1 GW coal, 6 GW gas, 2 GW cogeneration—of new thermal power plant capacity is likely (EGAT 2010). Another 21 GW (7 GW coal, 10 GW gas, and 4 GW cogeneration) is likely in the following decade (2021–2030).[2]

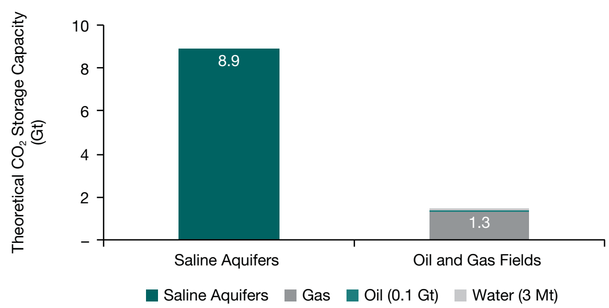
However, these new plants may represent future opportunities for capture. The study assumed that construction of new power-generation facilities would occur on or near existing power stations. In addition, replacement, or repowering of older plants, such as the coal power plants, may also provide another opportunity for CO_2 capture.

This Study Identified 10 Gigatons of Theoretical CO_2 Storage Capacity: 9 Gigatons in Saline Aquifers and the Rest in Oil and Gas Fields

The study developed estimates of the theoretical CO_2 storage capacity in saline aquifers below 1,000 meters and in oil and gas fields. On saline aquifers, 10 of the 94 sedimentary basins had sufficient data available to calculate storage capacities. Regarding oil and gas fields, 41 of the 71 oil and gas fields had adequate data to calculate the storage capacity. Although the study initially sought to assess storage opportunities in coal and shale, adequate data were not available to complete that assessment.

Available data on the sedimentary basin and oil and gas fields indicated a theoretical CO_2 storage capacity of 10 gigatons (Gt), as illustrated in Figure A3.3.

Figure A3.3 **Theoretical CO_2 Storage Capacity**



Gt = gigaton, Mt = megaton.

For saline aquifers, the initial screening assessment was conducted on the sedimentary basin scale. It involved data on geographic coordinates of the basin, basin depth, percentage of permeable sediments, average porosity of the permeable formations, and average pressure and temperature for each basin.

Although 9 Gt is the total theoretical CO_2 storage capacity of the saline aquifers, one basin alone of the 10 evaluated accounts for 65% of the storage capacity. Excluding the one large basin, the storage capacity of the remaining basins varies between 50–1,000 Mt with an average of approximately 350 Mt. This preliminary storage estimate represents only one-ninth of Thailand's sedimentary basins—the total storage capacity of saline aquifers in Thailand could be substantially larger.

[2] In June 2012, the Power Development Plan 2010–2030 (PDP 2010), which formed the basis of EGAT 2010, as revised was approved by the Government of Thailand (PDP 2010 Revision 3). This revised PDP was not available to the authors as this study was being conducted and finalized. Relative to the initial version, the July 2012 revision of the PDP adds a bit more of new coal in the near term and reduces coal in the longer term. Specifically, the PDP 2010 Revision includes the following: between 2012–2020, approximately 13.7 GW (2 GW coal, 6.5 GW gas, and 5.2 GW cogeneration); and between 2021–2030, approximately 22.5 GW (2.4 GW coal, 18.9 GW gas, and 1.27 GW cogeneration).

Commercial operational data of oil and gas wells were available and used for estimating CO_2 storage capacity in oil and gas fields. The data included cumulative production information for oil, water, and gas from each field including volume of water injected, if any, reserve estimates, formation volume factors for the oil and gas, average compositions of the oil, water and gas, initial reservoir temperature and pressure, depths of fields, and geographic coordinates of the fields. In addition to the storage capacity, the rate of CO_2 injection per well and time of field depletion were also estimated.

For depleted gas reservoirs, the capacity is from 246 Mt to less than 1 Mt per field, with a cumulative capacity of 1,340 Mt. For depleted oil reservoirs, the range is 26 Mt to less than 1 Mt per field with a cumulative capacity of 64 Mt. Water production only accounted for 3 Mt total capacity, a low number perhaps because the data on water produced were not available. Most of the depleted gas storage sites are located offshore, while depleted oil storage sites are located onshore and offshore almost equally. These oil-gas storage capacities are conservative estimates. Experience suggests that these estimates will increase as additional data about the fields becomes available. Even with current estimates, Thailand's CO_2 storage capacity in oil and gas fields can hold 140 years of emissions from power plants.

Most of the CO_2 Storage Capacities in Oil and Gas Fields Will Become Available by 2020

Annual production and proven reserves data were used to estimate when oil and gas fields would become available for CO_2 storage. The study estimates that approximately 90% of the storage capacities in oil and gas fields, or 1.3 Gt, will become available by 2020. Though these projections contain many uncertainties, experience suggests the fields will produce for longer than is indicated here based on the present reserve numbers. Nevertheless, these estimates provide a useful preliminary signpost for planning initial CCS project activities.

Oil and Gas Field Injection Rates Were Predicted to Be Adequate for CO_2 Storage

The estimated rate of injection and the number of wells per field are important characteristics for determining the daily flow volume for storage. For these calculations, annual production rates for oil and gas were used as a measure of minimum injection rates for CO_2. The largest predicted injection rates exceeded 30,000 t/day for a single field that had over 300 wells. A number of fields have injection rates of over 5,000 t/day per field. In practice, increasing the pressure differential between the surface and the reservoir during the injection of CO_2 will enhance injection rates. The injection rates and number of wells appear to be adequate for Thailand's emission sources.

The Top Three Oil and Gas Fields Offer Approximately Over 350 Megatons of CO_2 Storage Capacity

The 41 oil and gas fields underwent a ranking assessment to establish which fields were best suited for storage. The ranking methodology used a two-stage approach of qualifying and preferential criteria, as illustrated in Table A3.1. Preferential criteria are technical and economic attributes that can be used to judge storage suitability. Each oil and gas field was assessed quantitatively against all of the preferential criteria.

The maximum attainable score for each criterion reflects the importance of that criterion relative to the other criteria. For the oil-gas fields, the sum of scores they receive against the criteria represents the final score for storage suitability (with a maximum attainable score of 100, with an additional bonus of 5). The total score establishes the ranking among the fields.

The five highest-ranking fields have total scores ranging from 68 to 83. Together, these five fields represent approximately 500 Mt of CO_2, representing a third of the total storage potential in the oil and gas fields examined.

Table A3.1 **Criteria Used in Ranking Oil and Gas Fields for CO_2 Storage Suitability**

Qualifying Criteria	
Capacity	Capacity > 10 Mt CO_2, with exceptions for satellite fields
Injection rate	Injection rate > 100 t of CO_2/day/well
Injectivity and capacity	Reservoir > 3 m thick
Confinement: Depth	Depth to top of reservoir > 1,000 m
Confinement: Seal	Seal thickness > 3 m
Confinement: Faults	No active faults
Preferential Criteria	
Capacity	CO_2 storage (21)
Injection rate	CO_2 storage per day per well (11)
Injectivity and capacity	Number of existing production/injection wells (11)
Confinement: Depth	Seal thickness (14) Number of abandoned wells (4) Contamination of other resources (4)
Economics	Cost recovery (enhanced oil recovery or other offset) (17) Existing infrastructure (4) Monitoring opportunity (4) Availability (depletion date) (5, plus a bonus of 5 if both oil and gas reservoirs are in single field) Willingness of operator (5)

m = meter, Mt = metric ton, t = ton.

Note: Number within parenthesis indicates the maximum attainable score in each criterion.

Figure A3.4 illustrates the ranked oil and gas fields with their final score and storage capacity.

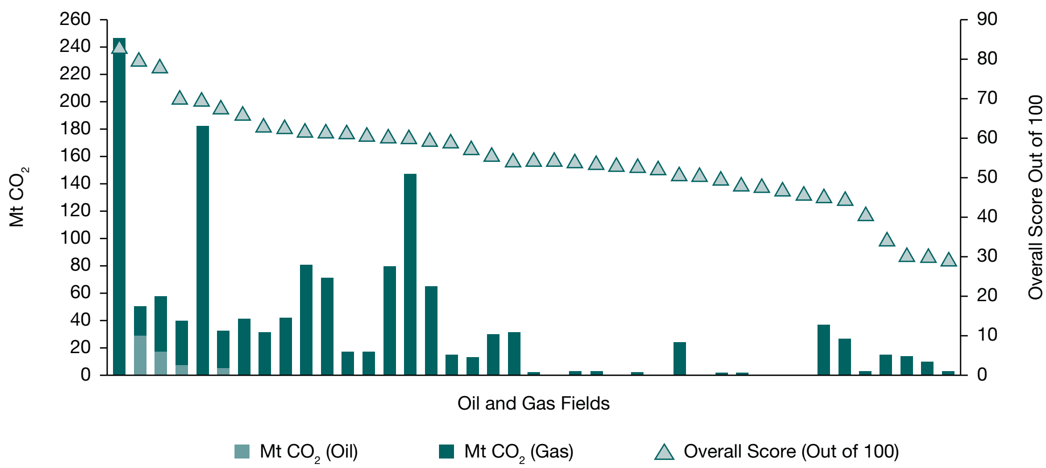
Early storage development would favor fields containing oil reserves. Enhanced oil recovery (EOR) through CO_2 injection offers an opportunity for offsetting part of the storage costs. Although injectivity is important for storage and constitutes a maximum score of 22 in the ranking methodology to reflect that importance, it is difficult to get accurate information on the number of operating wells and their operating history. There is also considerable uncertainty regarding the depletion date. However, because the maximum score for that criterion in the suitability ranking methodology is small, it will not play as important a role in determining the cumulative score of a field. The ranking may change when more accurate and complete data become available for assessing injectivity as well as the other preferential criteria.

The Study Recommends a Source–Sink Match for a Pilot Project that Will Allow for Continuity in the Storage Location through to Commercial Application

The study proposes commencing a CCS demonstration project in Thailand in approximately 5 years, around 2017, to be preceded by a pilot CCS project. The key initial step will be establishing the source–sink matching for the pilot project.

A pilot must yield information that will enable predicting conditions expected in a larger demonstration or full commercial operation. Continuity in the storage site is, therefore, essential from pilot to commercial. While incremental oil in the case of combined CO_2-EOR and CCS project is possible, the imperative is to gather information about reservoir performance.

Figure A3.4 **Oil and Gas Fields Ranked According to CO_2 Storage Suitability**



Mt = megaton.

With that motivation, the source–sink match for a pilot is established by first determining promising commercial-scale source–sink matches. Once that determination is made, the pilot can be designed using the sink chosen for a potential commercial opportunity but with the least expensive source of CO_2 irrespective of its long-term potential. The pilot can then be executed and, if successful, the demonstration project can then use CO_2 from the commercial capture source.

A typical pilot project involves injecting around 50–100 t of CO_2 per day over a short duration. A storage demonstration is larger, approximately 500–2,700 t/day and injects CO_2 over a longer period (10 years). For the pilot, the CO_2 transport could be by truck or boat as building a pipeline may not be justified for these low quantities of CO_2. If a demonstration project is subsequently justified, a pipeline will be required to transport the CO_2.

The dependency of the source is a key issue. It is not advisable to match a capture pilot to a storage pilot. Technical delays in piloting new capture technologies could make a dependable constant flow of CO_2 for the storage pilot uncertain. To avoid this, the least expensive source of existing CO_2 should be selected. Having sources and sinks close to each other is desirable but is not the most critical consideration.

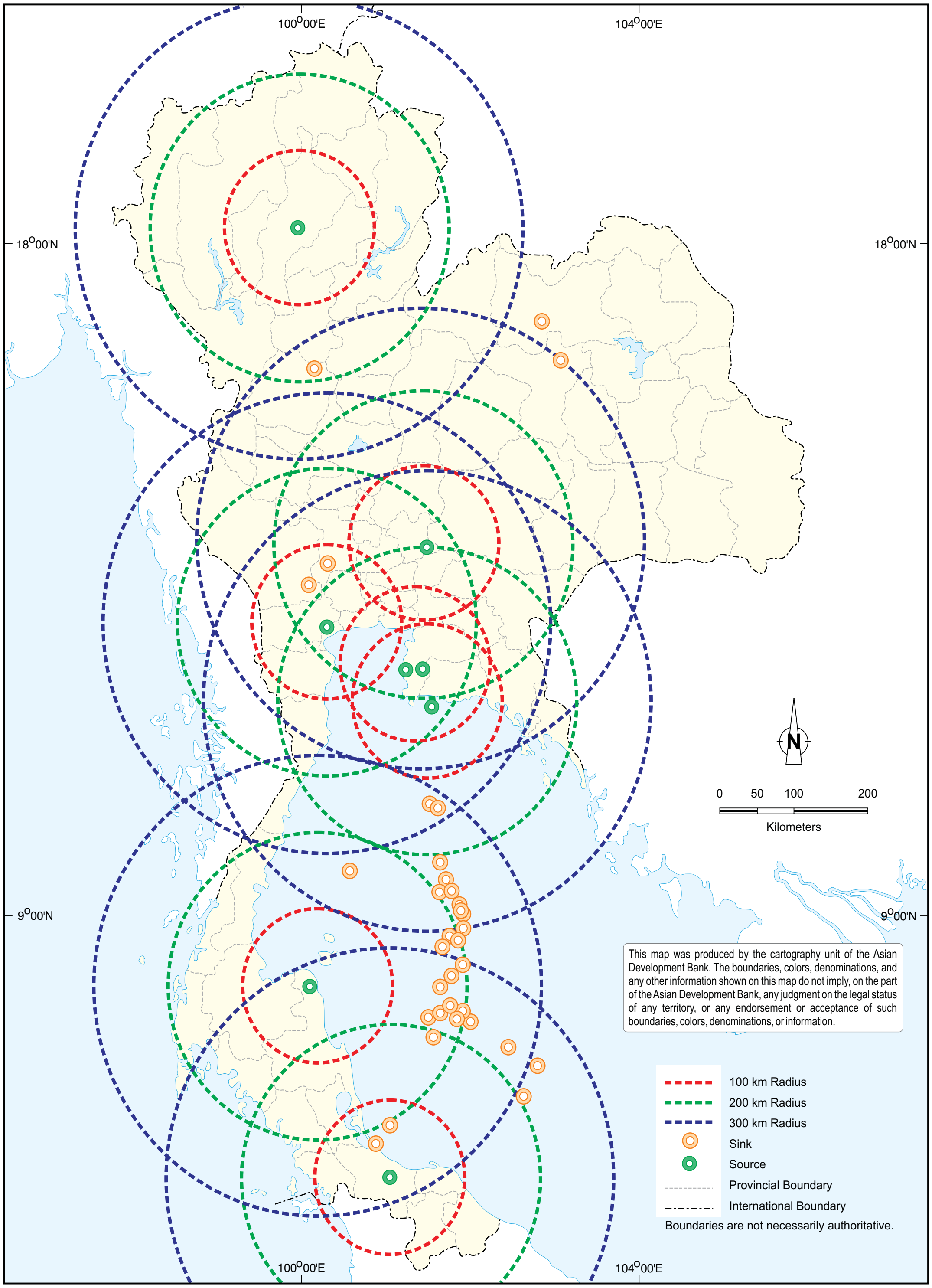
For pilots, the source should ideally be pure CO_2 or close to it. The sink should ideally be a large depleted oil or gas reservoir where the future storage costs can be offset by increased oil and gas production. The learning from a storage pilot is not readily transferrable from one field to another. Different geological parameters exist in each field, resulting in different geological models and different reservoir behaviors. Therefore, the study recommends conducting the storage pilot in an oil or gas reservoir that has commercial storage potential and matching it with a CO_2 source that offers inexpensive capture. The information from the pilot will determine whether a large demonstration is warranted both technically and economically.

The Largest Single CO_2 Source and Oil Field Lie in the North of Thailand

Natural gas-processing facilities just southeast of Bangkok and 300 km south of Bangkok feed into the cluster of offshore oil and gas fields storage sites in the Gulf of Thailand which offer the best source–sink matches. Figure A3.5 plots the top-ranked sources along with 100, 200, and 300 km circles around them to assess their distance from the top-ranked sinks.

The coal-fired power plant in the north is the largest emission source, with 18 Mt CO_2 emitted annually.

Figure A3.5 **Location of Sources and Sinks with 100, 200, and 300 km Distance from the Source**



Source: The Joint Graduate School of Energy and Environment.

It is within 200 km of an oil-rich field that is the second-ranked storage site with a CO_2 storage capacity of 49 Mt.

If the sources and sinks are judged in isolation, there is an attractive cluster of offshore oil and gas fields extending for 300 km in a north–south alignment in the Gulf of Thailand that contain the bulk of the CO_2 storage potential for the country. There is also an attractive cluster of sources just south of Bangkok. The cluster of sources just southeast of Bangkok with combined annual emissions of 23 Mt CO_2 and a natural gas–processing plant that alone accounts for 2 Mt CO_2 per year emissions emerge as the most attractive sources. Though the distance from these sources to the attractive offshore sinks exceeds 200 km, there are gas pipelines connecting the offshore fields to these plants. Much closer to the offshore fields and connected by pipeline is a natural gas–processing plant, 300 km south of Bangkok. Over the long term, these gas pipelines could be reversed and used to transport CO_2 to the depleted offshore fields. The longer 200 km distances from Bangkok sources to sinks becomes somewhat less important. The existence of these pipelines favors the latter natural gas–processing plant and the cluster of sources south of Bangkok for commercial demonstration. In this case, the initial CO_2 could come from one of the two natural gas–processing plants where the CO_2 waste stream is of high quality and the CO_2 capture cost is likely to be substantially less expensive.

Oil Reservoirs Are Favored for the First Storage Sites Due to CO_2-Enhanced Oil Recovery Potential

Oil reservoirs offer an opportunity to utilize the sink for incremental oil production that would offset the costs of capture, transportation, and storage. In such cases, there are two favored sites, one onshore and one offshore. A typical commercial CO_2-EOR operation ranges in size from 500–5,000 tCO_2 injected daily. The largest storage option based on original oil in place (OOIP) is estimated to have 26 Mt of CO_2 storage capacity, while the second largest is estimated to have 15 Mt of CO_2 storage. Assuming a very conservative net CO_2 utilization factor of 10 mcf (1,000 cubic feet) of CO_2 per barrel of oil produced, the incremental oil produced could be approximately 52 million barrels and 26 million barrels, respectively, for these fields. Provided that an inexpensive source of CO_2 can be identified, these two sites would be the prime focus for CO_2 storage demonstration projects.

Other potential oil targets in the offshore cluster of sinks include smaller storage options ranging from 1 Mt CO_2 to 6 Mt CO_2.

The Cluster of Offshore Sink Options Provide the Best Pilot for Carbon Capture and Storage That Could Pave the Way for a Future Demonstration Project

The key consideration for a pilot is that it must yield information that will enable predicting the conditions expected in a larger demonstration or full commercial operation. That imperative is the strongest factor in pilot location and design. The large-scale demonstration project should therefore determine the best sink for the pilot project. In this context, the oil-bearing fields in the offshore sink cluster appear to be the best options for the pilot since the storage potential of all the offshore sites is very large.

Carbon Capture and Storage Increases the Levelized Cost of Electricity from Supercritical Coal Plant by 74% and from Natural Gas Combined-Cycle Plant by 46%

The economic analysis illustratively evaluated the cost impacts on a supercritical pulverized coal (SCPC) power plant, a natural gas combined-cycle (NGCC) power plant, and an existing onshore natural gas–processing facility that is separating and subsequently venting (as a high purity stream) CO_2 to control CO_2 levels in the natural gas that is sold. In power plants, the cost impacts measure changes in the levelized cost of electricity (LCOE) from plants with and without CCS. In natural gas processing, the levelized cost impacts are measured in \$/tCO_2 captured terms.

The technical and cost data on power plants were taken from a 2011 report from the Global Carbon Capture and Storage Institute (Global CCS Institute 2011a), which contained updates of earlier estimates from the National Energy Technology Laboratory study (NETL

2010b). An Alstom (2011) report provided the basis for the pipeline and storage costs assumptions. A 2011 study by the Global CCS Institute was the basis for compression and dehydration cost assumptions for natural gas processing (Global CCS Institute 2011a). A 2008 NETL report provided the EOR assumptions (NETL 2008). The weighted average cost of capital (WACC), reflecting the financing parameters, was assumed to be 8.64%.

The study assumed a 546-megawatt net (MWnet) SCPC plant with CCS capturing approximately 4 Mt of CO_2 per year, with incremental capital costs for CCS of $2,806/kilowatt (kW) and incremental annual operating costs of $129 million. Similarly, for NGCC plant with CCS, the study assumed a capacity of 482 MW net, capturing approximately 1.4 Mt of CO_2 per year, with incremental capital costs for CCS of $1,444/kW and incremental annual operating costs of $21 million.

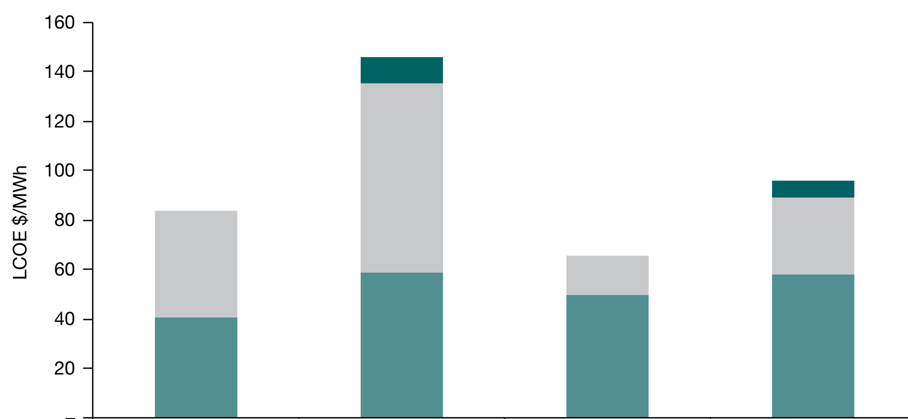
The analysis also used a nominal gas–processing plant case of 1 million metric tons per year CO_2 captured, with incremental capital costs at $167 million and incremental operating costs of $12 million per year. Figure A3.6 illustrates the impacts on LCOE of power plants with CCS.

As illustrated in Figure A3.6, the LCOE for a SCPC plant with CCS increases by 74%, or $61/MWh, relative to the reference plant without CCS. The incremental LCOE of an NGCC plant with CCS is somewhat more moderate at $30/MWh, representing an increase of 46% over the LCOE of the reference NGCC without CCS. For both coal and gas, capital cost accounts for the significant share of the *increase* in LCOE. These costs imply a CO_2 abatement cost of $90/t and $94/t of CO_2 avoided for SCPC and NGCC plants, respectively.

At an LCOE of $84/MWh, a new SCPC power plant without CCS is marginally below the current average wholesale electricity tariff in Thailand. The average wholesale electricity tariff of $88/MWh will not be sufficient to cover the LCOE of a pulverized coal power SCPC plant with CCS. Even a complete capital expenditure subsidy for the CCS components would only reduce the LCOE of a pulverized coal power SCPC plant with CCS to around $113/MWh, leaving it approximately $25/MWh higher than the current average wholesale electricity tariff.

A NGCC plant with CCS, however, is much closer to the current average wholesale tariff—only $7/MWh higher. A partial subsidy of $800/kW, or just about

Figure A3.6 Levelized Cost of Electricity Impacts on Power Plants from Carbon Capture and Storage



	Supercritical Pulverized Coal		Natural Gas Combined-Cycle	
	w/o CCS	w/ CCS	w/o CCS	w/ CCS
Transport and Storage	–	10	–	7
Capital and O&M	43	77	16	31
Fuel	41	58	50	58

CCS = carbon capture and storage, O&M = operation and maintenance.

half of the incremental capital expenditure for an NGCC plant with CCS, will result in a LCOE equal to the current average wholesale electricity tariff in Thailand.

The LCOE of a pulverized coal power SCPC plant and NGCC plants with CCS are both lower than the favorable feed-in-tariffs for generation from wind plants ($167/MWh). However, these renewable energy feed-in tariffs apply to much smaller levels of generation than would be the case from CCS power plants.

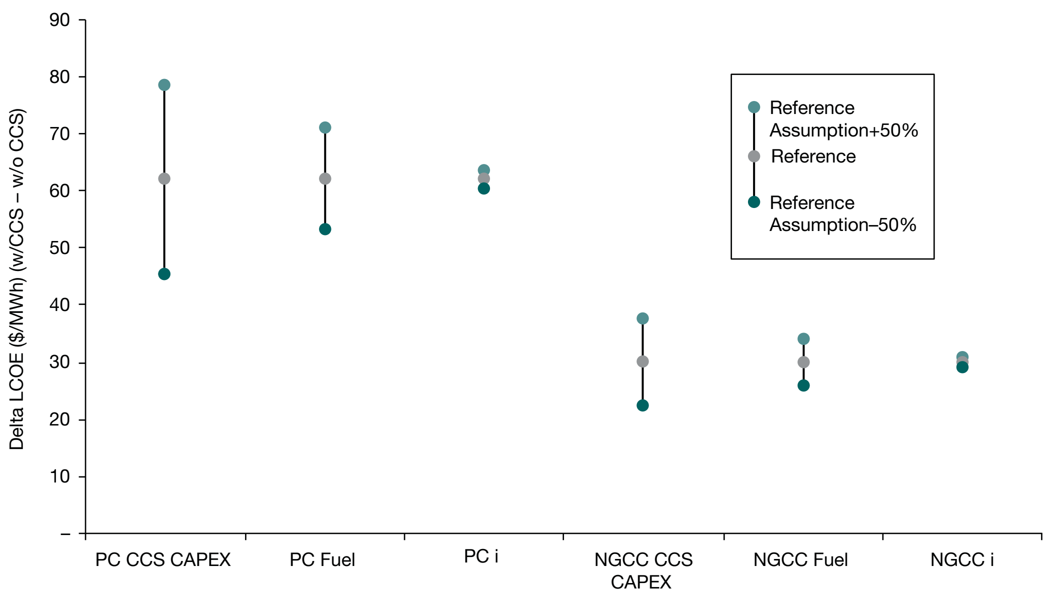
The LCOE impacts are sensitive to changes in the underlying assumptions. Capital expenditures appear to exert the greatest influence on the incremental (delta) LCOE for CCS in both the SCPC and NGCC case.

Figure A3.7 illustrates the range of delta LCOE (i.e., LCOE of plant with CCS and LCOE of plant without CCS) when the reference assumption is increased and decreased by 50% across several of the key assumptions. The delta LCOE is linear within the endpoints.

One way of financing a power plant with CCS is to compensate it for CO_2 mitigation by placing a value on the dollar per ton of CO_2 avoided. This value may result from a CO_2 credit, through a market or alternate scheme that prices emissions. It could also accrue as a revenue stream from EOR. In this case, the EOR revenue could be used to derive an equivalent implied credit price for dollar per ton of CO_2 avoided. Figure A3.8 illustrates the resulting range of delta LCOE under assumed oil prices ranging from $60/bbl to $140/bbl under two scenarios: (i) assuming no subsidy on capital expenditures (CAPEX) and only revenues generated from EOR, and (ii) assuming full subsidy of the capital expenditures associated only with the CCS component, including the EOR revenues (CCS CAPEX + EOR). The delta LCOE is linear within the two oil price bounds.

Lacking any form of capital subsidy, to offset the delta LCOE, a SCPC plant with CCS will require a credit price of approximately $90/t$CO_2$ avoided, which could be realized from oil prices of approximately $90/bbl. Similarly, without any form of capital subsidy, a NGCC power plant with CCS would require a credit price of $94/t$CO_2$ avoided to

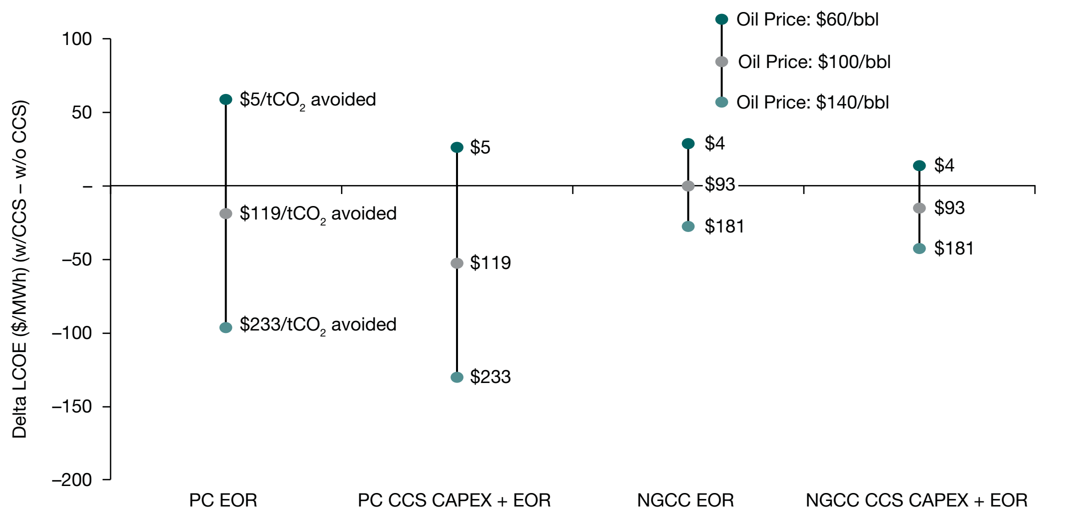
Figure A3.7 **Delta Levelized Cost of Electricity under Sensitivities to Key Assumptions**



CAPEX = capital expenditures, CCS = carbon capture and storage, Fuel = fuel prices, i = real interest rate, LCOE = levelized cost of electricity, NGCC = natural gas combined-cycle, PC = pulverized coal.

Note: CCS CAPEX denotes capital expenditures only for the CCS component.

Figure A3.8 **Impact on Delta Levelized Cost of Electricity from Variations in Oil Prices and Implied CO_2 Credit Prices**



bbl = barrel, CAPEX = capital expenditures, CCS = carbon capture and storage, EOR = enhanced oil recovery, LCOE = levelized cost of electricity, NGCC = natural gas combined-cycle, PC = pulverized coal, t = ton.

Notes: EOR denotes sensitivity assuming no subsidy on capital expenditures and only revenues generated from EOR; CCS CAPEX + EOR denotes sensitivity assuming that full subsidy of the capital expenditures associated only with the CCS component, including the EOR revenues.

fully offset the delta LCOE, which could be realized from an oil price of $100/bbl. However, when assessed against the prevailing average wholesale tariff for electricity at $88/MWh received in Thailand, the incremental LCOE of a supercritical plant with CCS is supported by a lower CO_2-EOR credit price of $85/t avoided at an oil price of $85/bbl, while for a NGCC plant with CCS, the corresponding value is $15/t of CO_2 avoided at an oil price of $65/bbl.

The figures also illustrate several instances (i.e., cases “PC-EOR” and “NGCC-EOR”) where the EOR revenues more than offset the incremental costs, resulting in a negative delta LCOE. Because the LCOE includes the benefit from EOR, such instances highlight cases where EOR revenues cover and exceed CCS costs. Such cases may not require additional subsidies or external funding, though power plants with CCS may require incentives to cover their loss in margin.

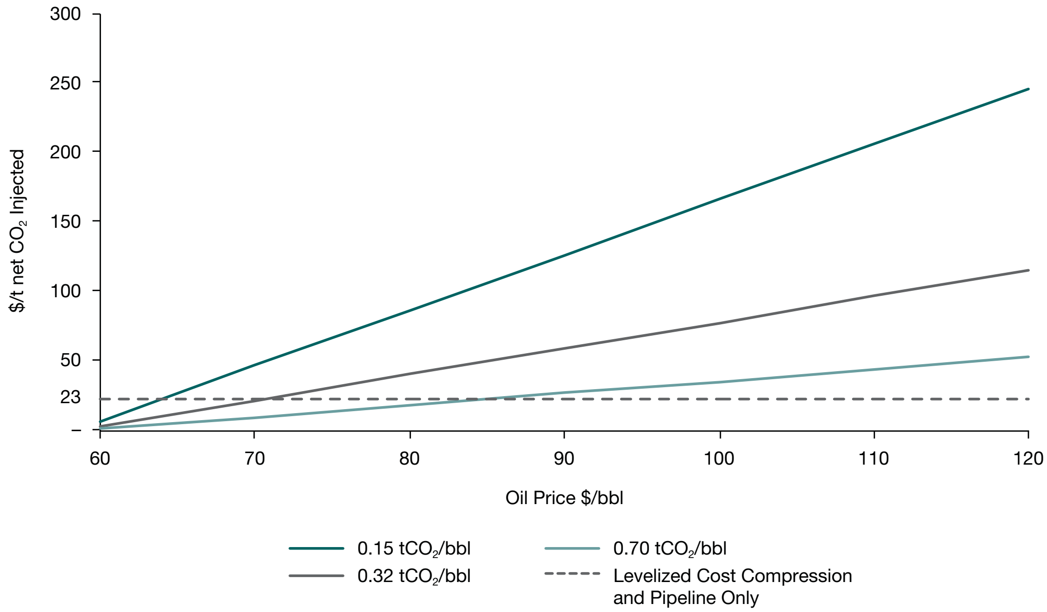
Figure A3.9 illustrates the levelized cost of capture for a natural gas–processing facility with EOR, along with the implied CO_2 credit price and related oil prices.

The levelized cost for a natural gas–processing facility capturing CO_2 without EOR is $29/t of CO_2 captured when storage costs are included. With EOR, the levelized cost drops to $23/t since the storage costs will then be borne by the EOR operator. At this level, an implied credit price of $23/t of CO_2 captured (oil price of $70/bbl at a CO_2 utilization rate of 0.32 t/bbl) should be able to cover the incremental cost.

Several Financing Options Must Be Explored to Offset Incremental Carbon Capture and Storage Costs

A wide variety of funding sources comprising government, multilateral, and bilateral development assistance, multilateral and bilateral climate-specific funds, and the private sector could be made available to offset the incremental costs of CCS. The Board of Investment and National Environment Fund offer a potential gateway for generating financial support. Thailand offers generous feed-in tariffs for renewables. For instance, tariffs for wind are approximately $167/MWh. Although these tariffs are

Figure A3.9 **Levelized Cost Impacts on Natural Gas Processing with Carbon Capture and Storage with Enhanced Oil Recovery**



bbl = barrel, t = ton.

applied to a smaller pool of generation, it illustrates the willingness of the government to offer incentives to expand the generation portfolio. Such measures alongside an alternative approach arising from revenues that can be generated from CO_2-EOR credit schemes must also be explored. The funding support for CCS is likely to draw from many sources and part of the process in building toward pilot and eventual commercial activity is to evolve an effective funding mechanism.

Existing Laws Need to Be Expanded to Provide the Legal and Regulatory Framework for Carbon Capture and Storage

There are no existing laws in Thailand that are specific to CCS. Wider deployment of CCS will require a legal and regulatory framework that, at a minimum, does the following: (i) classifies CO_2, (ii) defines surface and subsurface rights for CCS, (iii) specifies long-term stewardship and liability for CO_2, and (iv) develops regulations on environmental protection (including impact assessments), transport, health and safety, public participation, and foreign investment.

One possible approach toward the pilot may be to initiate a legal and regulatory review process to identify whether regulations or a legal framework will be required for the CCS pilot project. This could help determine the time by which a legal framework for CCS must be ready.

An Effective Communication and Engagement Strategy Must Parallel Carbon Capture and Storage Deployment

Public perceptions are often the most understated challenge to developing and deploying new technology. There is little public awareness about CCS. An effective communication strategy would ensure that there is an awareness-building campaign about CCS technology prior to deployment or even a pilot. In addition, deploying CCS must be accompanied by a comprehensive impact assessment. These studies should have broad participation, particularly of local stakeholders.

Local governments and communities should be invited as stakeholders to the CCS development process right from the preparation phase, through construction, operation, and into post-operations.

This Report Outlines a 20-Year Road Map Identifying Key Activities for a Pilot Project, Extending into a Demonstration and Building the Basis for a Longer-Term Commercial Project

The road map for CCS development involves a 20-year horizon, beginning with the pilot project design and construction, moving to demonstration project design in years 4 and 5, with the demonstration project start-up in year 10. The road map offers an outlook on year-to-year activities on all key aspects (storage, transport, capture, financing, government regulations, socioeconomic, impact assessment) and provides an approximate investment outlay of $60 million for a pilot project. The initial steps include validating this study's results and establishing funding sources for a pilot operation. The existing CCS working group could be the enabling body for implementing the road map activities.

Presuming a successful demonstration project, the road map proposes planning around year 15 for a scheduled full commercial-scale operation in year 20.

APPENDIX 4

Viet Nam Executive Summary

Carbon Capture and Storage Has the Potential of Achieving Deep Emission Reductions

Carbon capture and storage (CCS) is the only technology that can achieve deep reductions in carbon dioxide (CO_2) emissions from fossil fuel use in power plants and other industries. The CCS process involves four key components:

(i) Capture stage: capturing, dehydration, and compression of CO_2 from large stationary emission sources
(ii) Transport stage: transporting CO_2 by tankers, pipeline, or ship to a suitable storage site
(iii) Storage stage: injecting CO_2 deep underground for secure and permanent storage
(iv) Measurement, monitoring, and verification (MMV): for secure and permanent storage underground

Although CCS is yet to be widely deployed, several of its process components are commercially available and proven at a scale required for technology deployment. Globally, 74 large-scale integrated CCS projects are actively under consideration, of which 15 are operational or in advanced stages of development.

Much of the global effort on CCS has been limited to developed countries. For the potential of CCS to be fully realized, CCS must be increasingly deployed across developing Asia, where many new power plants and industrial facilities will be built.

This Study Offers a Road Map for Carbon Capture and Storage Deployment in Viet Nam

The report addresses several existing information gaps on CCS in Viet Nam by

(i) creating an inventory of CO_2 emission sources;
(ii) creating an inventory of possible storage sites and source–sink matches using secondary data and explicit screening criteria, for geological storage of captured CO_2;
(iii) ranking capture and storage sites and undertaking source-sink matching of capture and storage opportunities;
(iv) identifying a promising CCS pilot project or projects in conjunction with CO_2 enhanced oil recovery (EOR); and
(v) developing an internal network of agencies and personnel (CCS Working Group) with the capacity to carry projects forward.

The study was prepared by a team of national and international experts. It builds on previous CCS studies in the region and further examines sources, sinks, and transport options with the intent of offering an actionable and implementable road map for CCS development in Viet Nam.

Greenhouse Gas Emissions Are Projected to Triple to 516 Megatons by 2030

Viet Nam has been among the fastest-growing economies in Asia, with an average gross domestic product (GDP) growth of 7% annually over the last decade. The Asian Development Bank (ADB) predicts that through 2020, growth will remain in the 7.5%–8%

range, consistent with the outlook in the country's own sector plans such as the Power Development Plan 2011–2020 (PDP VII).

These levels of economic growth will be accompanied by sharp increases in energy use and emissions. Total final energy consumption is likely to grow on average by 4% annually, increasing from 51,000 ktoe (thousand metric tons of oil equivalent) in 2010 to 92,000 ktoe by 2025 (Gadde et al. 2011). Although hydropower and renewable energy will remain an important part of the energy mix, the increased use of fossil fuels will supply much of the growth in energy demand.

Total greenhouse gas (GHG) emissions are projected to grow at approximately 6% annually, three times the annual growth rate between 2000 and 2010, to reach 516 megatons of CO_2 equivalent (Mt CO_2e) by 2030 (NATCOM 2010). Emissions from the energy sector will account for almost all of the growth in GHG emissions.

Viet Nam has begun to develop specific policies to respond to the challenges of climate change. In December 2008, the Ministry of Natural Resources and Environment issued the National Target Program to Respond to Climate Change (NTP-RCC) seeking to assess climate impacts, develop feasible response action plans, explore opportunities to develop toward a low carbon economy, and join international mitigation efforts.

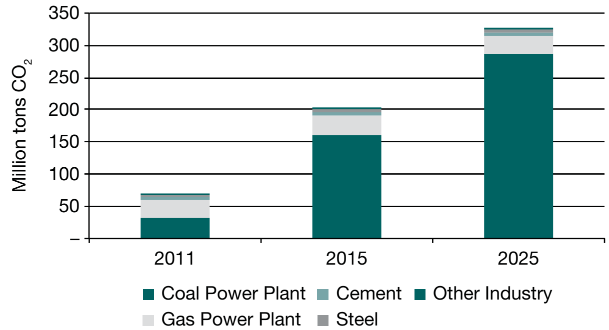
CCS offers an opportunity for realizing deep reductions in emissions from coal- and gas-fired power plants, natural gas-processing and fuel-transformation facilities, and in industrial sectors such as iron-steel, chemicals, and cement.

The study has identified several potential sources of CO_2 capture from power plants. Increased production from high-CO_2-content gas fields in the future could also ensure a steady supply of CO_2 for CCS. As production from existing oil fields declines, CCS offers the opportunity for increased oil production through enhanced oil recovery (EOR).

Study Identified Potential Emission Sources Totaling 325 Megatons by 2025

The emission source inventory was assembled using data from the Institute of Energy supplemented with a questionnaire that was sent to power plants and industrial sources. Data on future power plants were gathered from the Power Development Plan 2011–2030 (PDP VII). As illustrated in Figure A4.1, the source inventory represents 325 Mt of CO_2 in 2025.

Figure A4.1 **Viet Nam Emissions Inventory**



Note: Gas includes four oil units totaling 4 Mt of emissions in 2011; Other Industry includes beverage, fertilizer, pulp and paper, washing powder, cement, and steel, but does not include emissions from future plants.

The inventory included approximately 35 coal plants in 2025 with annual average emissions of 8 Mt per plant. The 2025 inventory also included four gas power plants with annual average emissions of 7 Mt across the plants. Annual average emissions from steel (0.5 Mt), cement (1 Mt), and other industries were much smaller.

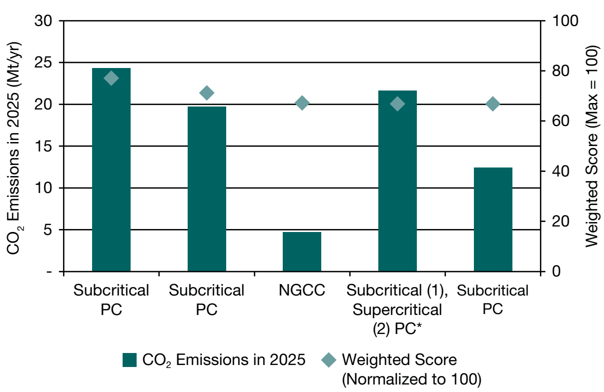
From the emissions inventory, the study elected to focus on existing and future power plants as the best potential sources for capture. Following the inventory of sources, a two-step ranking methodology was developed to assess the suitability of CO_2 capture. In the first step, plants had to satisfy the qualifying criteria. The qualifying criteria required plants to have a remaining operational life of at least 20 years and have limited operational variability. Only plants that met both these criteria moved to the second stage.

Of the power plants, 28 met the qualifying criteria and moved to the second step of the methodology. This step involved 11 preferential criteria that measured the suitability and compatibility with available CO_2 capture technologies. All criteria had varying degrees of importance. Each criterion was given a weight that reflected its relative importance among the set of criteria.

The qualifying sources were then measured against each criterion. They were provided a score, ranging from 0 (least desirable) to 10 (most desirable), indicating how well it measured on that particular criterion. For each potential source, a composite index value was developed by first multiplying the score on each criterion with the weight for that criterion (i.e., weighted score), and then second, for each source, the weighted score achieved against each of the criterion was totaled to obtain the total weighted score for that source. This total weighted score was then used to rank the sources.

Figure A4.2 illustrates the top-ranked CO_2 emission sources according to the suitability of capture. The annual emissions represented in Figure A4.2 describe the total plant-level emissions. Each plant has several units. Except for one natural gas combined-cycle (NGCC) plant, the other sources are all coal plants that will go online by 2020.

Figure A4.2 **CO_2 Emission Sources Ranked by Suitability for Capture**

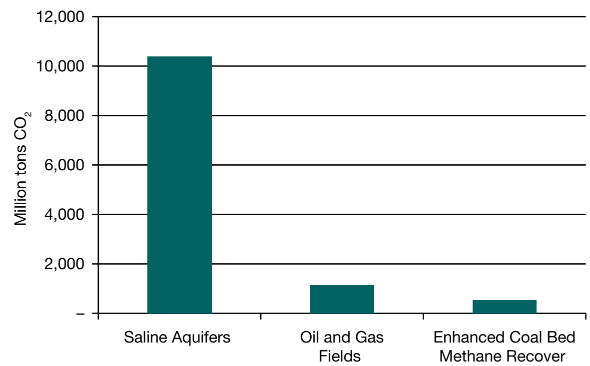


NGCC = natural gas combined-cycle, PC = pulverized coal.
*(1) one unit subcritical, (2) two units are supercritical.
Note: Total plant-level emissions are reported; each plant has several units.

The Study Identified 12 Gigatons of Theoretical CO_2 Storage Capacity in Viet Nam

Storage capacity was estimated for saline aquifers, oil and gas fields and enhanced coal bed methane (ECBM) recovery. As illustrated in Figure A4.3, the estimate theoretical storage capacity is

Figure A4.3 **Theoretical Storage Capacity**



approximately 12 gigatons (Gt) of CO_2, though much of this is concentrated in saline aquifers. These are conservative estimates, reflecting data limitations and an effort to bound uncertainty.

The theoretical cumulative storage capacity of Viet Nam's saline aquifers exceeds 10 Gt of CO_2. It represents the storage capacity of the geological plays in six of the eight of Viet Nam's sedimentary basins: Song Hong, Phu Khanh, Cuu Long, Nam Con Son, Malay–Tho Chu, and Tu Chinh–Vung May. Song Hong and Phu Khanh offer the largest storage capacity at approximately 2.5 Gt of CO_2.

This estimate includes the restriction of only storing CO_2 in stratigraphic and structural traps. If that restriction were removed, the calculated capacity would exceed 300 Gt. In addition, only petroleum plays were considered. Barren saline aquifers that had not transported petroleum in the past were not considered. These barren saline aquifers would also add to the theoretical capacity. This estimate will become more precise as the geology of Viet Nam's basins is further defined. This initial estimate clearly suggests that the saline aquifers are large enough to justify further quantification of Viet Nam's geological CO_2 storage potential.

CO_2 can be used in ECBM recovery to enhance the recovery of natural gas from coal due to its selectivity over methane for sorption on coal. Injection of CO_2 will displace the methane. Coal bed methane (CBM) development is in its infancy in Viet Nam. A study in 2010 concluded that seven areas in Viet Nam have high CBM potential. CO_2 storage capacity was estimated for only one of the seven CBM areas—Ha Noi Trough (Red River delta) for which appropriate data existed.

The total theoretical CO_2 storage capacity of the coal in the eight blocks of the Ha Noi Trough was estimated at 458 Mt. This value represents the cumulative coal from 300 to 1,500 meters.

A total of 34 oil and gas fields are in production or will be in the near future in the offshore Viet Nam area. These fields represent a key CO_2 storage potential. If only storage capacities of fields greater than 10 Mt CO_2 are considered, the effective storage capacity of the oil and gas fields in four of the eight Vietnamese sedimentary basins (Cuu Long, Malay–Tho Chu, Nam Con Son, Song Hong) is 1.15 Gt CO_2, with the largest field exceeding 300 Mt CO_2 capacity. This storage will be available when the fields are depleted or when CO_2-EOR occurs.

The Top 14 Oil and Gas Fields Offer 900 Megatons of CO_2 Storage Capacity

This study ranked the prospective gas and oil fields based on storage suitability. Oil and gas fields are the leading storage options because of their ability to help offset storage cost with increased production of oil and gas. In addition, unlike saline aquifers, oil and gas also have existing infrastructure that can be used toward CO_2 transportation.

The ranking methodology used a two-stage approach of qualifying and preferential criteria, as illustrated in Table A4.1. Fields had to meet the qualifying criteria to be evaluated for the preferential criteria.

The fields were scored against the preferential criteria. The maximum attainable score in each criterion reflects the importance of that criterion relative to the other criteria. For each field, the sum of scores across the criteria represents the final score for storage suitability (maximum attainable score of 100). The total score for each field establishes the ranking of storage suitability among the fields.

Figure A4.4 illustrates the results of the storage ranking analysis. Fields CL01 and CL16 had the highest scores. Field CL16 offers the single largest storage capacity with over three times the capacity (357 Mt) of any other field.

The Study Recommends Selecting a Source–Sink Pilot Match That Will Allow for Continuity in the Storage Location through to Commercial Application

The study outlines a 15-year road map beginning with a pilot, which will lead to the demonstration and finally commercial application. The key initial step will be to identify the source–sink for the pilot project.

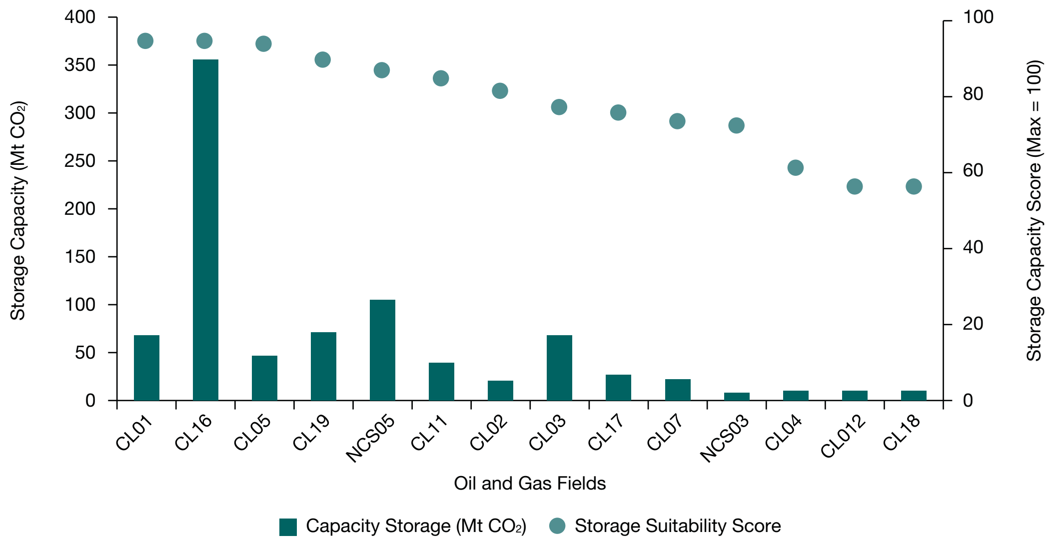
Table A4.1 **Two-Stage Process for Ranking Oil and Gas Fields for CO_2 Storage Suitability**

Qualifying Criteria	
Capacity	Capacity > 10 Mt CO_2, with exceptions for satellite fields
Injection rate	Injection rate > 100 t of CO_2/day/well
Injectivity and capacity	Reservoir > 3 m thick
Confinement	Seal thickness > 7 m with no active faults
Preferential Criteria	
Capacity	CO_2 storage (21)
Injectivity	CO_2 storage per day per well (10) Number of existing production/injection wells (10)
Confinement: Depth	Seal thickness (16) Number of abandoned wells (4) Contamination of other resources (4)
Economics	Cost recovery (enhanced oil recovery or other offset) (17) Existing infrastructure (4) Monitoring opportunity (4) Availability (depletion date) (5) Willingness of operator (5)

m = meter, Mt = metric ton, t = ton.

Note: Number within parenthesis indicates the maximum attainable score in each criterion.

Figure A4.4 **Oil and Gas Fields Ranked by CO_2 Storage Suitability**



A pilot must yield information that will allow predicting the incremental oil production and CO_2 storage expected in a larger demonstration or full commercial operation. Continuity in the storage site is, therefore, essential from pilot to commercial scale. While incremental oil in the case of a combined CO_2-EOR and CCS pilot is possible, the essential imperative is to gather information about reservoir performance.

With that motivation, the source–sink match for the pilot can be established by first determining commercial scale source–sink matches. Once that determination is made, the pilot can be designed using the sink chosen for the commercial plan but with the least expensive source of CO_2 irrespective of its long-term potential. Once the pilot is executed and deemed successful, the demonstration project can use CO_2 from the commercial capture sources as soon as they are developed.

A typical pilot project involves injecting around 50–100 tCO_2/day over a short duration. A storage demonstration is larger, approximately 500–2,700 tCO_2/day and injects CO_2 over a longer period (over 10 years). For the pilot, the CO_2 transport could be by truck or boat as the construction of a pipeline will not be justifiable for these low quantities of CO_2. If a demonstration project is subsequently justifiable, a pipeline will be required to transport the CO_2.

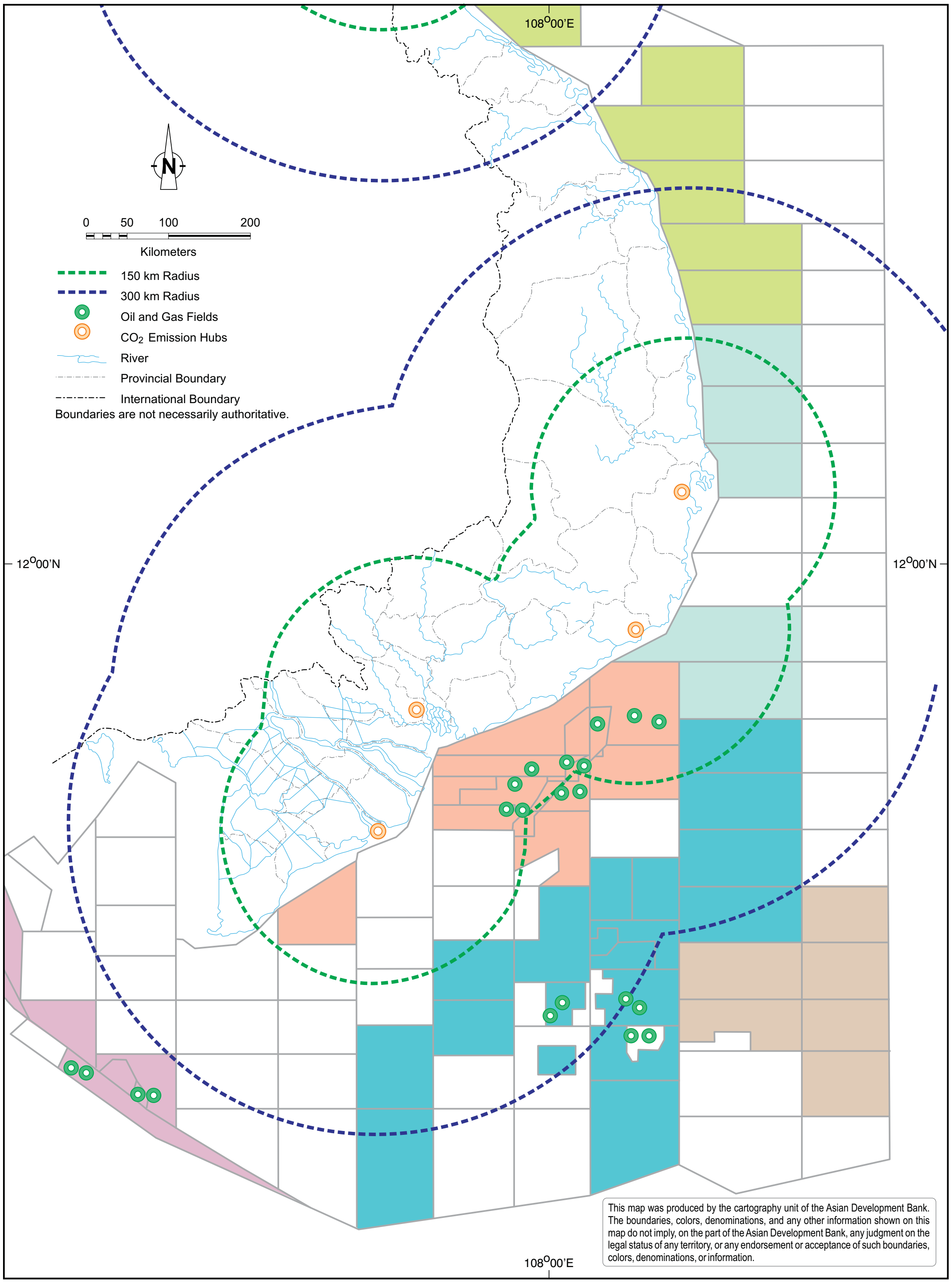
Proposed Pilot Should Center on Oil and Gas Storage Options in the Cuu Long Basin

The 10 top-ranked individual storage sites range in capacity from 23 Mt CO_2 to 357 Mt CO_2. Based on sources that will produce 2–5 Mt annually over 20 years, the cumulative production will be between 40 Mt CO_2 and 100 Mt CO_2. The top-ranked sources and sinks appear matched in size.

South Viet Nam offers the best options. The most promising oil and gas fields lie in the Cuu Long Basin, within 150 km of many CO_2 sources (Figure A4.5). The oil and gas fields in the Malay–Tho Chu and Nam Con Son basins also offer good storage potential. The focus for storage should be on the Cuu Long Basin. The best storage targets are the CL16, CL01, CL05, CL11, CL02, CL03, CL17, and CL19 fields.

All the large emission sources in South Viet Nam are coal- or gas-fired power plants, and lie within 300 km of an oil or gas field for storage (Figure A4.5). Most are within 150 km of a sink in the Cuu Long Basin. Larger gas-processing sources of pure CO_2 may become available in the future when the high-CO_2 gas fields in other basins are developed, which will result in large pure sources of CO_2 from the processing chain being available for capture.

Figure A4.5 **150 and 300 km Circles Around Short-Listed CO_2 Sources in Viet Nam**



Source: Institute of Energy.

For a demonstration project, this analysis has established four emission hubs and one storage hub in South Viet Nam. The CO_2 emission hubs will be at a natural gas power plant and the coal power plants. The CO_2 storage hub consists of the eight fields in the Cuu Long Basin listed earlier. If the first demonstration is successful, it will allow long-term planning for the development of multiple CO_2 sources in South Viet Nam and multiple storage sites in the Cuu Long Basin, possibly justifying the construction of a CO_2 backbone pipeline in South Viet Nam.

One of the key objectives of the study was to identify a suitable source–sink pilot. Depending on availability, the oil fields in the offshore sink cluster in the Cuu Long Basin appear to be the strongest prospects. Currently, the only source of pure CO_2 is from the fertilizer plant, but the plant is capturing almost all of its CO_2 for fertilizer production. Depending on the season, however, it may be possible to source CO_2 for pilot operations from this fertilizer plant. Planned coal and expansion NGCC power plants that ranked high for capture suitability could also be good capture candidates.

CCS Increases the Levelized Cost of Electricity from Supercritical Coal Plants by 78% and from Natural Gas Combined-Cycle Plants by 55%

The economic analysis illustratively evaluated the costs impacts on a supercritical pulverized coal (SCPC) power plant, a NGCC power plant, and existing onshore natural gas–processing facility that is separating and subsequently venting (as a high-purity stream) CO_2 to control CO_2 levels in the natural gas that is sold. In power plants, the cost impacts measure changes in the levelized cost of electricity (LCOE) from plants with and without CCS. In natural gas processing, the levelized cost impacts are measured in terms of the \$/tCO_2 captured.

The technical and cost data on power plants were taken from a 2011 report from the Global Carbon Capture and Storage Institute (Global CCS Institute 2011a), which contained updates of earlier estimates from power plant case studies published by the National Energy Technology Laboratory (NETL 2010b). An Alstom (2011) report provided the basis for the pipeline and storage costs assumptions. The 2011 Global CCS Institute study was also the basis for compression and dehydration cost assumptions for natural gas processing. Another NETL (2008) report provided the EOR assumptions. The weighted average cost of capital (WACC), reflecting the financing parameters, was assumed to be 9.6%.

The study assumed a 546 MWnet SCPC plant with CCS capturing approximately 4 Mt of CO_2 per year, with incremental capital costs for CCS of \$2,902/kW and incremental annual operating costs of \$117 million. Similarly, for NGCC plant with CCS, the study assumed a capacity of 482 MWnet, capturing approximately 1.4 Mt of CO_2 per year, with incremental capital costs for CCS of \$1,493/kW and incremental annual operating costs of \$20 million.

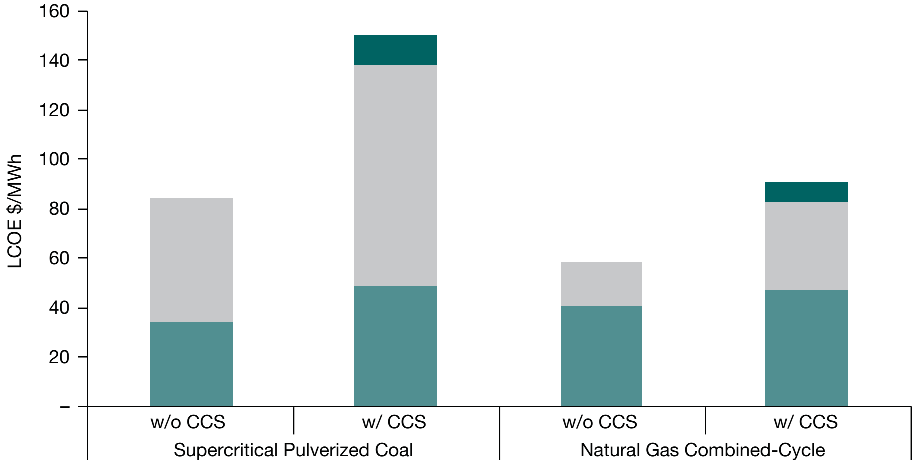
The analysis also used a nominal gas–processing plant case of 1 Mt/yr CO_2 captured, with incremental capital costs at \$171 million and incremental operating costs of \$11 million per year. Figure A4.6 illustrates the impacts on LCOE of power plants with CCS.

As illustrated in Figure A4.6, the LCOE for a SCPC plant with CCS increases by 78%, or \$66/MWh, relative to the reference plant without CCS. The incremental LCOE of an NGCC plant with CCS is somewhat more moderate at \$32/MWh, representing an increase of 55% over the LCOE of the reference NGCC without CCS. For both coal and gas, capital cost accounts for the significant share of the *increase* in LCOE. These costs imply a CO_2 abatement cost of \$95/t and \$99/t of CO_2 avoided for SCPC and NGCC plants, respectively.

The current generation tariff earned by coal and natural gas-power plants, approximately \$45/MWh for both, is not adequate to support a new SCPC plant and a new NGCC plant, respectively. Although this analysis benchmarks existing generation tariff, it is worth noting that there is already an inbuilt system inefficiency that will need to be corrected in the future. As new plants enter the system, the current generation tariff provided to the new plants must be comparable to the LCOE of a SCPC plant without CCS and a NGCC plant without CCS.

The LCOE impacts are sensitive to changes in the underlying assumptions. Capital expenditures appear to exert the greatest influence on the incremental

Figure A4.6 **Levelized Cost of Electricity Impacts on Power Plants from Carbon Capture and Storage**



	Supercritical Pulverized Coal w/o CCS	Supercritical Pulverized Coal w/ CCS	Natural Gas Combined-Cycle w/o CCS	Natural Gas Combined-Cycle w/ CCS
Transport and Storage	–	12	–	7
Non-Fuel (Capital & O&M)	50	89	18	36
Fuel	34	49	40	47

CCS = carbon capture and storage, LCOE = levelized cost of electricity, O&M = operation and maintenance.

(delta) LCOE for CCS in both the SCPC and NGCC plants cases.

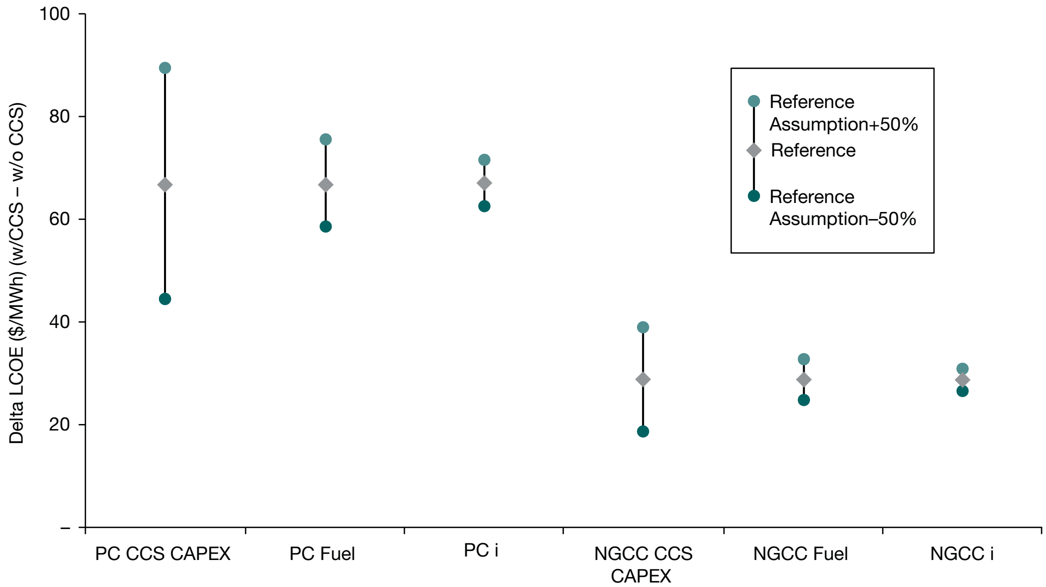
Figure A4.7 illustrates the range of delta LCOE (i.e., LCOE of a plant w/CCS less LCOE of a plant without CCS) when the reference assumption is increased and decreased by 50% across several of the key assumptions. The delta LCOE is linear within the endpoints.

One way of financing a power plant with CCS is to compensate the plant for CO_2 mitigation by placing a value on the $/t of CO_2 avoided. This value may result from a CO_2 credit, through a market or alternate scheme that prices emissions. It could also accrue as a revenue stream from EOR. In this case, the EOR revenue could be used to derive an equivalent implied credit price for $/t of CO_2 avoided. Figure A4.8 illustrates the resulting range of delta LCOE under assumed oil prices ranging from $60/bbl to $140/bbl under two scenarios: (i) assuming no subsidy on capital expenditures and only revenues generated from EOR, and (ii) assuming that full subsidy of the capital expenditures (CAPEX) associated only with the CCS component, including the EOR revenues (CCS CAPEX + EOR). The delta LCOE is linear within the two oil price bounds.

Without any form of capital subsidy, to offset the delta LCOE, a SCPC plant with CCS will require a credit price of approximately $90/t$CO_2$ avoided at the power plant, which could be realized from oil prices of approximately $90/bbl. Similarly, without any form of capital subsidy, a NGCC power plant with CCS would require a credit price of $93/t$CO_2$ avoided at the power plant to fully offset the delta LCOE, which could be realized from an oil price of $100/bbl. However, when assessed against the prevailing current generation tariff of $45/MWh, the LCOE of a SCPC plant with CCS requires a higher CO_2-EOR credit price of $147/t avoided at an oil price of $110/bbl, while for a NGCC plant with CCS, the corresponding value is $137/t of CO_2 avoided at an oil price of $120/bbl. This higher support requirement reflects the fact the current generation tariff for coal and gas are both much lower than the LCOE of a new unit without CCS.

The figure also illustrates several instances (i.e., cases “PC–EOR” and “NGCC–EOR”) where the

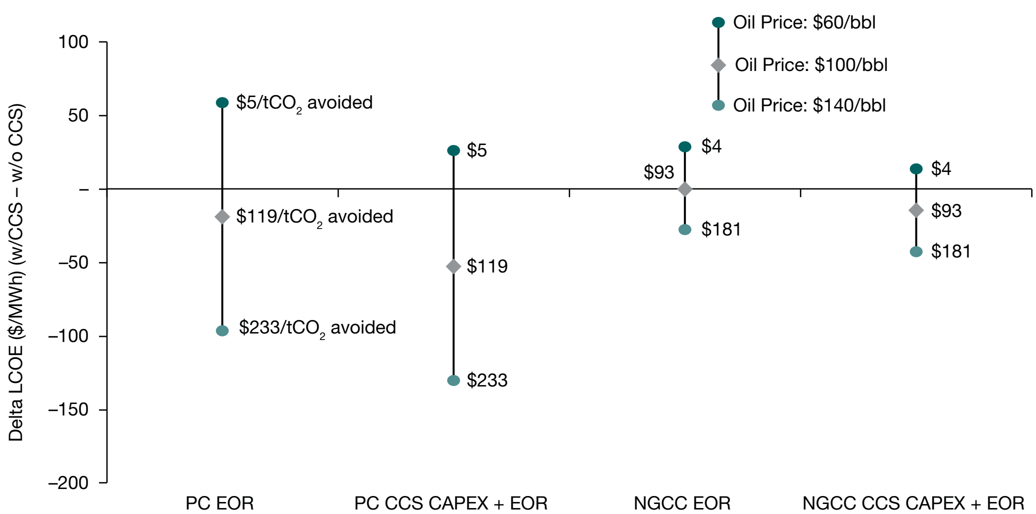
Figure A4.7 **Delta Levelized Cost of Electricity under Sensitivities to Key Assumptions**



CAPEX = capital expenditures, CCS = carbon capture and storage, Fuel = fuel prices, i = real interest rate, LCOE = levelized cost of electricity, NGCC = natural gas combined-cycle, PC = pulverized coal.

Note: CCS CAPEX denotes capital expenditures only for the CCS component.

Figure A4.8 **Impact on Delta Levelized Cost of Electricity from Variations in Oil Prices and Implied CO_2 Credit Prices**



CAPEX = capital expenditures, CCS = carbon capture and storage, EOR = enhanced oil recovery, LCOE = levelized cost of electricity, NGCC = natural gas combined-cycle, PC = pulverized coal.

Notes: EOR denotes sensitivity assuming no subsidy on capital expenditures and only revenues generated from EOR; CCS CAPEX + EOR denotes sensitivity assuming that full subsidy of the capital expenditures associated only with the CCS component, including the EOR revenues.

EOR revenues more than offset the incremental costs, resulting in negative delta LCOE. Because the LCOE includes the benefit from EOR, such instances highlight cases where EOR revenues exceed CCS costs. Such cases may not require additional subsidies or external funding, though power plants with CCS may require incentives to cover their loss in margin.

Figure A4.9 illustrates the levelized cost of capture for a natural gas–processing facility with EOR, along with the implied CO_2 credit price and related oil prices.

The levelized cost for a natural gas–processing facility capturing CO_2 without EOR is $28/t of CO_2 captured when storage costs are included. With EOR, the levelized cost drops to $22/t since the storage costs will then be borne by the EOR operator. At this level, an implied credit price of $23/t of CO_2 captured can be derived from an oil price of $70/bbl assuming a CO_2 utilization factor of 0.32 tCO_2/bbl of oil.

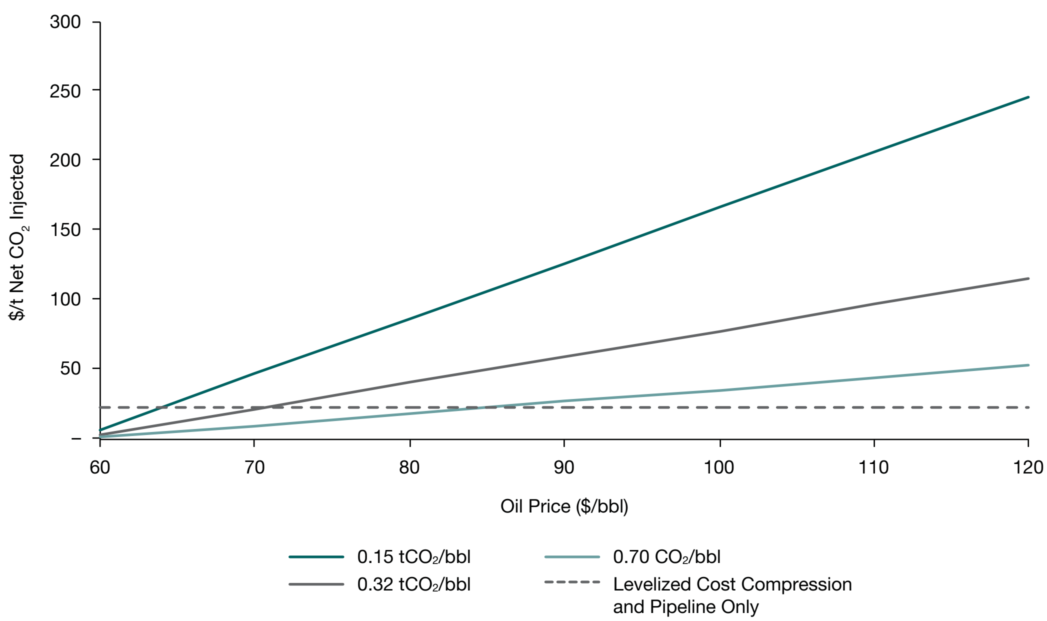
A wide variety of funding sources, comprising government, multilateral, and bilateral development assistance, multilateral and bilateral climate-specific funds, and the private sector, must be explored to offset the incremental costs of CCS. The application of government support around loan guarantees, tax incentives, and clean technology initiatives must also be looked at, along with the possibility of revenues from CO_2-EOR. The funding support for CCS is likely to draw from many sources, and part of the process in building toward pilot and eventual commercial activity is to evolve an effective funding mechanism.

Regulations for Carbon Capture and Storage Will Need to Be Developed and Will Require Coordination across a Number of Government Institutions

Developing the regulations for CCS will require cooperation between government ministries, primarily the Ministry of Natural Resources and Environment and the Ministry of Industry and Trade, as well state-owned enterprises that undertake such projects.

CCS will require policy and regulations on a wide number of issues, such as subsurface rights, environmental, health and safety, long-term liability,

Figure A4.9 **Levelized Cost Impacts on Natural Gas-Processing with Carbon Capture and Storage with Enhanced Oil Recovery**



monitoring, measurement, and verification. Existing regulations are not adequate to meet the needs for CCS. Many of these regulations will need to be developed.

An Effective Communication and Engagement Strategy Must Parallel Carbon Capture and Storage Deployment

Public perceptions are often the most understated challenge to development and deployment of new technology. There is little public awareness about CCS. An effective communication strategy would ensure that there is an awareness-building campaign about CCS technology prior to deployment or even a pilot. In addition, deployment of CCS in Viet Nam must be accompanied by a comprehensive impact assessment. These studies should have broad participation, particularly of local stakeholders. Local governments and communities should be invited as stakeholders to the CCS development process, starting from the preparation phase and continuing through construction, operation, and into post-operations.

This Report Outlines a 15-Year Road Map Identifying Key Activities for a Pilot Project, Extending into a Demonstration and Building the Basis for Longer-Term Commercial Projects

The road map for CCS development involves a 15-year horizon, beginning with the pilot project design and construction, moving to demonstration project design in year 5, with the demonstration project start-up in year 10.

The road map offers an outlook on year-to-year activities on all key aspects (storage, transport, capture, financing, government regulations, socioeconomic, and impact assessment) and provides an approximate investment outlay of $60 million for a pilot project. The initial steps include the validation of this study's results and establishing funding sources for a pilot operation. The existing CCS working group could be the enabling body for implementing the road map activities.

Presuming a successful demonstration project, the road map proposes planning around year 15 for a scheduled full commercial-scale operation (expansion of the demonstration project) in year 20.

APPENDIX 5

Scale of Carbon Capture and Storage Projects: Pilot vs. Demonstration vs. Commercial

Although a commercial project is the final goal of carbon capture and storage (CCS) development, commercial opportunities must be identified first as a basis for the pilot. That is, source–sink matching should be completed first using a commercial scale option (see Chapter 5) to identify pilot opportunities.

In addition, because there are often scale mismatches between piloting capture technology and storage sites, the initial pilot for a potential commercial operation should focus either on the capture or storage site. Due to timing and cost, in most cases, the pilot would be designed around the potential commercial storage site. If this is true, then the carbon dioxide (CO_2) source would be chosen based on storage piloting needs (i.e., 50–100 tons per day [t/day] or 18,000–37,000 t/year) and supply cost. In most cases, supply would not come from the potential commercial capture site. If the pilot is successful, then the potential commercial capture site would have to be developed for the demonstration project (i.e., 500–2,700 t/day or 183,000–1,000,000 t/year), with sufficient capability for a commercial storage project (i.e., 2,700–30,000 t/day or 1,000,000–11,000,000 t/year) depending on the commercial source.

A commercial-scale operation for CO_2 capture depends on the industry producing the CO_2 waste stream. For coal-fired power plants, a full-scale capture plant would be about 4 megatons of CO_2 per year (Mt CO_2/year) assuming a 550 megawatt (MW) base plant using bituminous coal. For gas-fired power plants, it would be reduced to about 1.5 Mt/year as the carbon intensity is less than that for coal. For gas-processing and fertilizer plants, the range is currently large, but usually smaller than 1,000 t/day or 365,000 t/year. To make significant reductions in CO_2 emissions, a commercial project should be approximately 1 Mt/year (2,700 t/day) or larger by targeting the larger CO_2 point sources. The largest sources in most countries are generally from power plants. Therefore, the geological storage of CO_2 requires that reservoirs be identified that can handle large quantities of CO_2 over the commercial operating lifetime of the plant (e.g., 20 years) for a total cumulative storage capacity exceeding 20 Mt CO_2.

However, a mismatch to the classification outlined arises when an EOR opportunity is identified as an early mover for CCS, where the income from the produced oil helps to offset the cost of storage and can transition into CO_2 storage projects over time. Commercial CO_2-enhanced oil recovery (EOR) projects can be much smaller, as low as 300 tCO_2/day. In such special cases, instances would arise where a smaller source gas-processing plant has been shown to be adequate for a commercial CO_2-EOR operation. If this is transformed into a storage project as the EOR project winds down, it is conceivable that this small-scale storage project could be considered commercial. Consequently, there could be two scales of commercial projects: (i) those less than 2,700 t/day which are derived from commercial EOR projects, and (ii) those greater than 2,700 t/day which are designed for depleted gas reservoirs, saline aquifers, and some larger EOR projects.

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Prospects for Carbon Capture and Storage in Southeast Asia

This report was produced under the Technical Assistance Grant: Determining the Potential for Carbon Capture and Storage (CCS) in Southeast Asia (TA 7575-REG), and is focused on an assessment of the CCS potential in Thailand, Viet Nam, and specific regions of Indonesia (South Sumatra) and the Philippines (CALABARZON). It contains inventories of carbon dioxide emission sources, estimates of overall storage potential, likely source-sink match options for potential CCS projects, and an analysis of existing policy, legal, and regulatory frameworks with a view toward supporting future CCS operations. The report also presents a comparative financial analysis of candidate CCS projects, highlights possible incentive schemes for financing CCS, and provides an actionable road map for pilot, demonstration, and commercial CCS projects.

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