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Assessment of the capture and storage potential of CO_2 co-produced with natural gas in South-East Asia

May 2010

CO2CRC Technologies

UNSW
THE UNIVERSITY OF NEW SOUTH WALES
SYDNEY • AUSTRALIA

APEC Project EWG 06/2008A

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Final report

Prepared by UNSW and CO2CRC Technologies

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- BP Indonesia - BP Berau Ltd
- Indonesian Executive Agency For Upstream Oil and Gas Business Activities (BPMigas)
- Chevron Thailand Exploration and Production Ltd.
- Thailand's Ministry of Energy.
- Thailand's Department of Mineral Fuels, Ministry of Energy
- Oil Search Ltd
- PetroVietnam Exploration Production Corporation
- Petronas Carigali Sdn Bhd
- Petronas
- PT Shell Indonesia
- Total E&P Indonesie
- Statoil Indonesia

The following individuals contributed to preparing the text and the analyses for this report —

Peter Neal (CO2CRC and the University of New South Wales (UNSW)), Wanwan Hou (CO2CRC and UNSW), Olga Bukhteeva (CO2CRC and UNSW), Yildiray Cinar (CO2CRC and UNSW), Geoff McKee (advisor to CO2CRC), Damian Dwyer (Australian Petroleum Production & Exploration Association Limited (APPEA)) and Guy Allinson (CO2CRC and UNSW).

Frank Mourits (Natural Resources Canada and Canadian representative on the APEC Expert Group on Clean Fossil Energy) was the Project Overseer and initiator of this project.

David Hilditch of CO2CRC Technologies Pty Ltd (CO2TECH) managed the commercial aspects of this project. CO2TECH is the commercial arm of the Cooperative Centre for Greenhouse Gas Technologies (the CO2CRC).

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Disclaimer

CO2TECH conducted this analysis and prepared this report using reasonable care and skill consistent with normal industry practice. All results are based on information available at the time of review. Changes in factors upon which the review is based could affect the results. Forecasts are inherently uncertain because of events or combinations of events that cannot be foreseen including the actions of government, individuals, third parties and competitors. No implied warranty of merchantability or fitness for a particular purpose shall apply.

Some of the information on which this report is based has been provided by other organisations. CO2TECH has used such information without verification unless specifically noted. CO2TECH accepts no liability for errors or inaccuracies in information provided by others.

Summary

The aims of this report as set out in the terms of reference for the study are as follows —

(a) “to assess the techno-economic feasibility of reducing CO_2 emissions resulting from natural gas production in South-East Asia through the application of CCS technologies, specifically by re-injecting the gas into subsurface geological formations”

and

(b) “a combination of promoting awareness, building capacity and developing human capital in the discovery of CCS.”

Existing projects

There are no full-scale operating CO_2 transport and injection projects in South-East Asia in which CO_2 is extracted from a natural gas development and the CO_2 subsequently stored or used for enhanced oil or gas recovery. However, there are several significant existing or planned gas-field CO_2 storage projects elsewhere in the world. The main features of these projects are summarised below and described in more detail in the body of this report.

Main features of existing or planned gas-field CO_2 injection and storage projects worldwide

Project	Sleipner	Snøhvit	In Salah	Weyburn-Midale (CO_2 EOR) (*)	Gorgon
Economy	Norway	Norway	Algeria	Canada	Australia
Basin	North Sea	Hammerfest	Ahnet-Timimoun	Williston	Barrow Sub-Basin
Formation	Utsira	Tubåen	Krechba	Midale	Dupuy
CO_2 injection rate in Mt/yr	1	0.7	1	2.8	2.7 to 3.2
Number and type of wells	1 × 1,250 m perforated horizontal	1 vertical	3 × 1,000 m perforated horizontal	650 production & 289 injection (Weyburn only)	9 vertical

(*) Included for comparison; not a natural gas development project

The existence of these projects demonstrates in general terms the technical viability of CO_2 injection and storage associated with gas field developments.

Storage technologies

CO_2 transport and injection using CO_2 extracted from natural gas field developments can be applied to store the CO_2 and/or can be used to enhance oil or gas recovery. CO_2 can be stored in saline formations or depleted or producing oil or gas fields. Storage in saline formations is achieved by one or more of several trapping mechanisms, namely stratigraphic, structural, hydrodynamic and/or geochemical trapping. Storage in depleted oil or gas fields has similar features, but the pressure regime in depleted reservoirs is likely to be different to that in saline formations and this will have a significant effect on the design of the injection system.

Storage in producing oil or gas fields is likely to have the added advantage of improving oil or gas recovery. As regards enhanced oil recovery using CO_2 (CO_2 EOR), the additional recovery might occur through miscible or immiscible flooding. The suitability of a reservoir for EOR depends on the characteristics of that reservoir and properties of the oil it hosts.

Some geological basins have reservoir characteristics that might be more suited to CO_2 EOR than others. Our preliminary filtering suggests that the Malay and N.W. Java basins might be suitable candidates for CO_2 EOR. However, this does not mean that other basins in South-East Asia are not worthy of consideration. Our preliminary ranking of formations for CO_2 EOR is given below. This is a first-pass approximate ranking using rock properties only. The best formation has a rank of 1. The tabulation is intended to prioritise those formations that might be worthy of further investigation.

First pass ranking of formations for CO_2 EOR based on rock properties only

Formation	Basin	Economy	Rank
H Group	Malay B.	Malaysia &	1
Talang Akar Fm	N.W. Java B.	Indonesia	2
Batu Raja Fm	N.W. Java B.	Indonesia	3
D, E, F & G Group	Malay B.	Malaysia	4
Terumbu Fm	E. Natuna B.	Indonesia	5
Cycle V	Baram Delta B.	Brunei	6
Nam Con Son Fm	Nam Con Son B.	Vietnam	7
Peutu Fm	N. Sumatra B.	Indonesia	8
Pattani Trough	G. of Thailand B.	Thailand	9
Miocene Delta Sst	Kutei B.	Indonesia	10
Lower Kembelangan Gp	Bintuni B.	Indonesia	11
Sihapas Gp Sst	C. Sumatra B.	Indonesia	12
J Group	Malay B.	Vietnam	13
I Group	Malay B.	Vietnam	14
K Group	Malay B.	Malaysia &	15
L Group	Malay B.	Vietnam	16
Pematang Fm	C. Sumatra B.	Indonesia	17

Therefore, CO_2 EOR works better with particular reservoir conditions. In addition, it is typically applied to depleting reservoirs with relatively low production. Finally, the economics of CO_2 EOR depends on favourable oil and CO_2 prices. These factors imply that, while some CO_2 EOR projects might be economically viable, such projects might not in total require volumes of CO_2 that are significant when compared to the volumes emitted from South-East Asian gas developments.

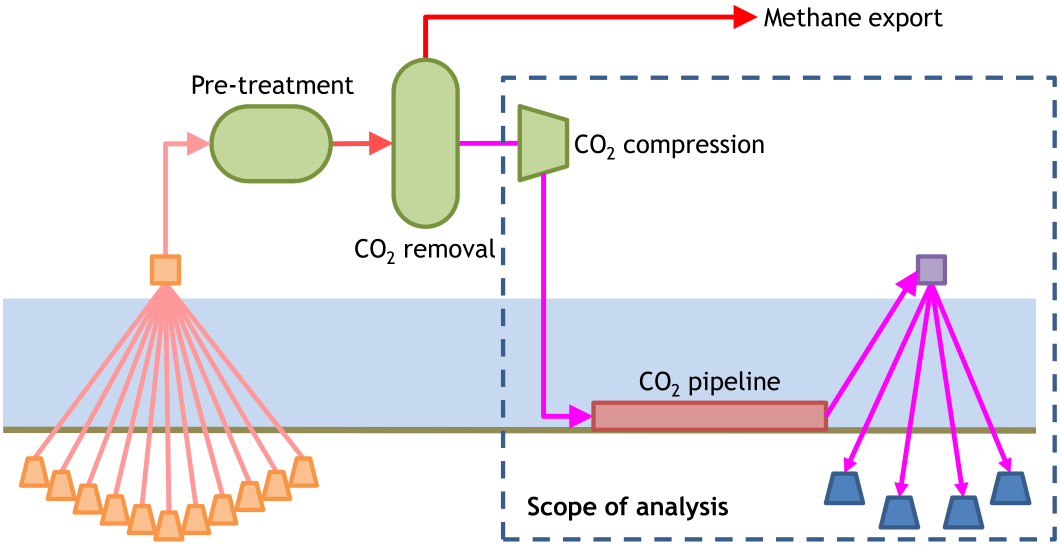
As regards enhanced gas recovery using CO_2 (CO_2 EGR), the technology has not been applied extensively and is in its infancy. To our knowledge, it has not been applied to enhance gas production in South-East Asian reservoirs.

Gas-to-liquids (GTL) conversion might be an appropriate means of using the CO_2 co-produced with natural gas from high-CO_2 reservoirs.

From the perspective of reducing CO_2 emissions, CO_2 EOR, CO_2 EGR and GTL are not strictly comparable to CO_2 storage. Enhanced recovery produces additional hydrocarbons and GTL combines methane and CO_2 into different hydrocarbons. These hydrocarbons are ultimately burned and therefore cause additional CO_2 emissions to the atmosphere unless the emissions are captured and stored.

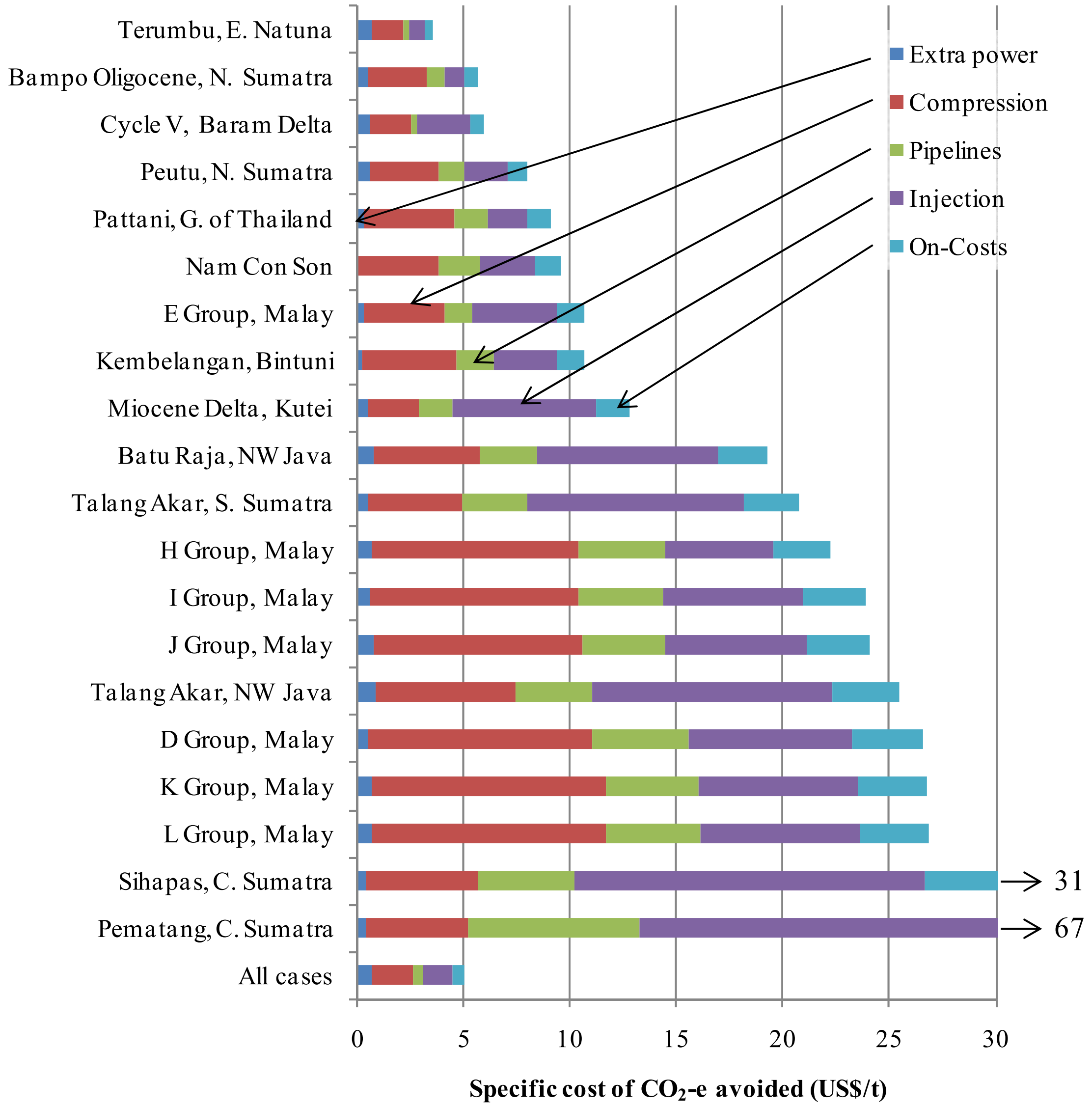
Representative case analyses

We analyse CO_2 transport and storage from representative natural gas discoveries in geological formations across South-East Asia. The representative analyses illustrate the design of CO_2 transport and injection, its capital, operating and decommissioning costs, as well as the specific cost of CO_2-e avoided (see Section 4 for a definition of this). A schematic diagram of the process is shown below. We assume that the storage site is sited 10 km from the production facility.



The analyses are based on limited cost and reservoir data and incorporate a large margin of error. This reflects the high degree of uncertainty in estimating injection reservoir characteristics and unit costs.

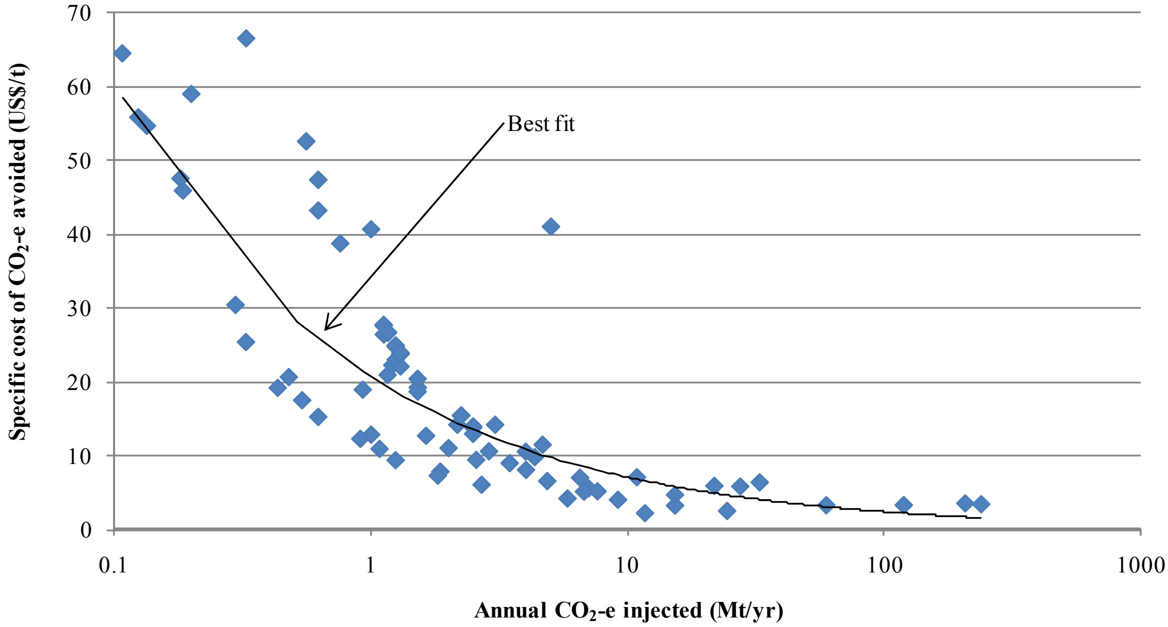
Our best central estimates of the cost per tonne avoided are shown below ignoring the effects of the fiscal terms. We estimate the range of costs for individual basins from US\$4 to US\$67 per tonne of CO_2-e avoided in US\$2010 terms depending on the project. Typically, approximately a quarter to a half of the cost is for injection wells and platforms. Compression machinery and associated platforms account for a further quarter of the costs. The capital costs for the projects range from approximately US\$70 million to almost US\$5 billion.



Costs per tonne of CO_2-e avoided for different formations across South-East Asia

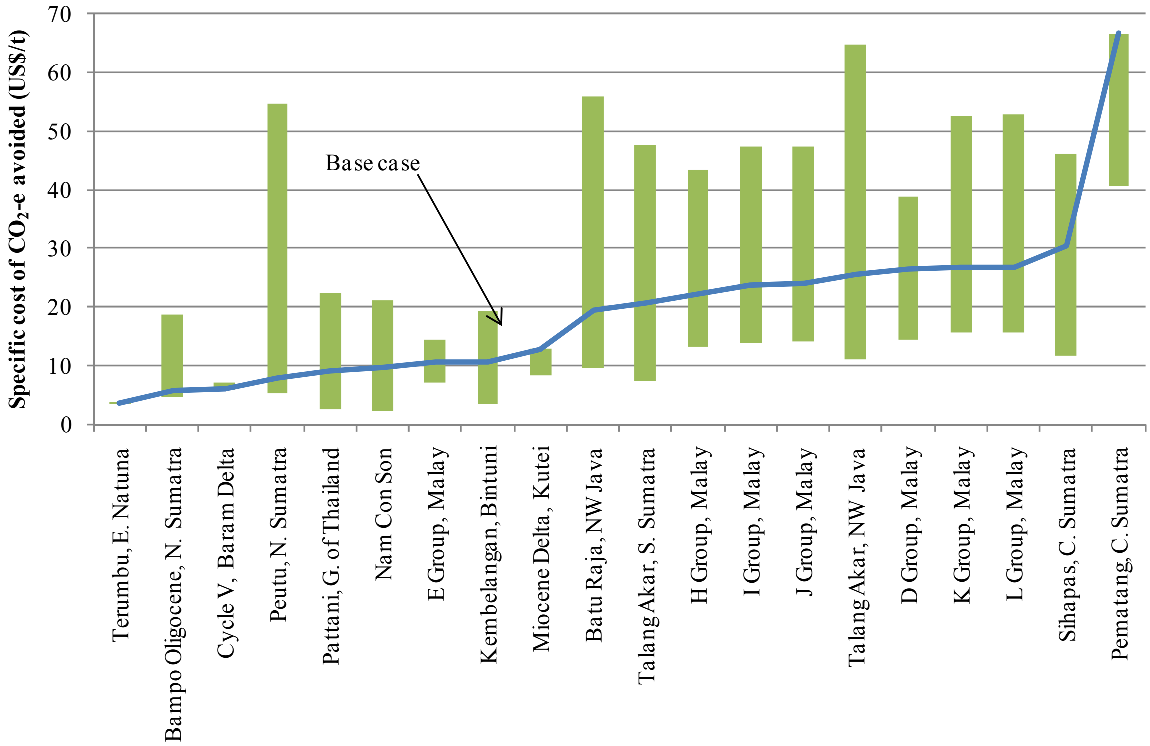
Economies of scale have a significant effect on costs per tonne of CO_2-e avoided. The scatter diagram below illustrates this. It shows the results of all the cases analysed and the line of best fit between the estimated costs. The line of best fit shows that the specific cost of CO_2-e avoided typically drops below US$20 per tonne avoided for injection rates over 1 Mt/yr and below US$10 per tonne for injection rates over 6 Mt/yr. For smaller injection rates the costs increase markedly.

The diagram shows that, ignoring fiscal considerations, many projects would be economic with a price of carbon of US$20 per tonne.



The effects of economies of scale as injection rate increases

The scatter diagram above shows also that there is considerable variation in the costs depending on the case. This feature is illustrated better in the figure below, which uses the same results in a different way. It shows the costs for the base cases as a line and the potential variation in costs as vertical bars. It is clear that the rate of CO_2 injection has a significant bearing on costs.



Variation in cost with changing injection rate

The diagram shows that even with injection rate variations, a significant number of cases have costs less than US$20 per tonne.

We have calculated the average cost[1] across all cases and for each economy. The average across all cases is approximately US$5 per tonne of CO_2-e avoided. This is cheaper than all but two of the individual cases because those two cases comprise 80% of all CO_2-e avoided in our analyses. According to our analyses, CO_2 storage in the selected basins in Indonesia has the lowest average cost at US$4 per tonne of CO_2-e avoided. Storage in the selected basins in Vietnam is the most expensive with an estimated average cost of US$18 per tonne avoided.

Effects of fiscal terms

Even though some Governments in South-East Asia are considering how CO_2 transport and injection might be treated in the fiscal and contractual terms for natural gas extraction, to our knowledge no firm fiscal or contractual arrangements are in place.

The fiscal terms for natural gas production across South-East Asia are such that Governments receive a significant share of the net cash flow from each project. We refer to this as Government take. Government take consists of royalties, income and other taxes, Government profit sharing, domestic oil supply obligations and so on. It is typically well over 50% of the net cash flow from a natural gas development.

In the absence of any additional revenue through a carbon price or enhanced recovery and if the costs of CO_2 transport and injection are to be treated in the same way as the costs of natural gas extraction, then the high Government take implies that the fiscal relief on such costs would be considerable. Our illustrative analyses suggest that such relief might be between 40% and 90% of the costs. This would make CO_2 transport and storage significantly cheaper and thereby more attractive. This is shown in the table below.

Economy	Basin	Cost of CO_2 avoided in US$/t		
		Formation	Before Government Take	After Government Take
Indonesia	Bintuni	Kembelangan	10.7	2.6 – 4.6
Indonesia	East Natuna	Terumbu	3.7	0.9 – 1.6
Indonesia	N.W. Java	Batu Raja	19.3	4.7 – 8.2
Indonesia	N.W. Java	Talang Akar	25.5	6.2 – 10.8
Indonesia	North Sumatra	Bampo Oligocene	5.7	1.4 – 2.4
Indonesia	North Sumatra	Peutu	8.0	2.0 – 3.4
Indonesia	Central Sumatra	Sihapas	30.5	7.4 – 12.9
Indonesia	Central Sumatra	Pematang	66.6	16.0 – 28.0
Indonesia	South Sumatra	Talang Akar	20.8	5.0 – 8.8
Indonesia	Kutei	Miocene Delta	12.8	3.1 – 5.4
Malaysia	Malay	D Group	26.5	3.2 – 9.9
Malaysia	Malay	E Group	10.7	1.3 – 4.0
Malaysia / Vietnam	Malay	H Group	22.2	2.7 – 8.3
Malaysia / Vietnam	Malay	K Group	26.7	3.3 – 9.9
Vietnam	Malay	I Group	23.9	2.9 – 8.9
Vietnam	Malay	J Group	24.0	2.9 – 8.9
Vietnam	Malay	L Group	26.9	3.3 – 10.0
Vietnam	Nam Con Son	Nam Con Son	9.6	3.2 – 5.7
Thailand	Gulf of Thailand	Pattani	9.1	2.8 – 5.7
Brunei	Baram Delta	Cycle V	6.0	2.1 – 3.1
Average			19.5	3.9 – 8.0

[1] This is a simple average across the individual representative discoveries considered. We do not weight the average by the total resource in each formation.

However, enhanced recovery as a result of CO_2 transport and storage would provide additional revenues for the gas developments. A carbon trading regime might also provide additional revenues. In these circumstances, the fiscal terms in South-East Asia might adversely affect CO_2 transport and storage. For instance, our illustrative analyses show that under conservative assumptions, the average minimum CO_2 price required to make a CO_2 transport and injection project commercial would need to be almost twice the average minimum price required if there was no Government take.

Economy	**Basin**	**Minimum price of CO_2 in US\$/t [(i)]**		
		Formation	**Before Government Take**	**After Government Take**
Indonesia	Bintuni	Kembelangan	10.7	15.5
Indonesia	East Natuna	Terumbu	3.7	5.4
Indonesia	N.W. Java	Batu Raja	19.3	28.0
Indonesia	N.W. Java	Talang Akar	25.5	37.0
Indonesia	North Sumatra	Bampo Oligocene	5.7	8.0
Indonesia	North Sumatra	Peutu	8.0	11.3
Indonesia	Central Sumatra	Sihapas	30.5	44.8
Indonesia	Central Sumatra	Pematang	66.6	98.6
Indonesia	South Sumatra	Talang Akar	20.8	30.3
Indonesia	Kutei	Miocene Delta	12.8	18.7
Malaysia	Malay	D Group	26.5	59.2
Malaysia	Malay	E Group	10.7	23.7
Malaysia / Vietnam	Malay	H Group	22.2	49.2
Malaysia / Vietnam	Malay	K Group	26.7	59.5
Vietnam	Malay	I Group	23.9	53.1
Vietnam	Malay	J Group	24.0	53.3
Vietnam	Malay	L Group	26.9	59.8
Vietnam	Nam Con Son	Nam Con Son	9.6	16.5
Thailand	Gulf of Thailand	Pattani	9.1	14.9
Brunei	Baram Delta	Cycle V	6.0	8.7
Average			19.5	34.8

(i) The table shows the approximate minimum prices per tonne of CO_2 avoided required to ensure that the net present values of the CO_2 transport and injection projects at least zero.

The analyses suggest that taking the fiscal terms into account, many transport and injection projects could be economically viable at carbon prices less than US$60 per tonne.

Case studies

We analyse case the economics of potential CO_2 transport and injection associated with two gas discoveries. One is the Tangga Barat natural gas discovery offshore Malaysia. The other is the Natuna natural gas discovery offshore Indonesia. Both discoveries have high CO_2 content. CO_2 comprises over 30% of the raw gas in the Tangga Barat discovery and over 70% of the raw gas in the Natuna discovery.

CO_2 injection for Tangga Barat will require 4 injection wells and the capital costs of CO_2 transport and storage is estimated to be US$220 million, with annual operating costs of US$8 million. Approximately 2.5 million tonnes of CO_2-e per year will be injected into the subsurface. The estimated specific cost is US$14 per tonne of CO_2-e avoided ignoring fiscal effects. This is within the range of representative specific costs estimated for the Malay Basin on a similar basis.

In the absence of any benefits from a carbon trading regime, our costs estimates translate into a cost of between US$2 and US$5 per tonne avoided after taking fiscal effects into account. Conversely, if a carbon trading regime applied and the carbon price yields revenues that are treated in the same way as revenues from gas sales, the minimum carbon price required to justify CO_2 sequestration would be US$26 per tonne avoided.

The other case analysed in the Natuna discovery. No firm plans for the development of this discovery have been made. Therefore, the CO_2 transport and injection scheme analysed here is only one of several possibilities and is shown simply as an illustration. In addition, CO_2 injection costs for the Natuna discovery are subject to large uncertainties because of large uncertainties in the properties of the injection formation.

Based on an illustrative development, the capital costs of CO_2 transport and storage for Natuna are estimated to be at least US$1,975 million, with annual operating costs of almost US$180 million. Approximately 80 million tonnes of CO_2-e per year will be injected into the subsurface. The estimated specific cost is at least US$7 per tonne of CO_2-e avoided ignoring fiscal effects. This is about twice the representative specific costs estimated for the East Natuna Basin on a similar basis, but the representative case has double the flow-rate. In addition, as mentioned above, the characteristics of the potential storage reservoir are very uncertain. If less favourable reservoir parameters are assumed, then the specific costs could be significantly higher than US$7 per tonne of CO_2-e avoided.

The uncertainties mentioned above can have a significant effect on the results of the economic analysis.

In the absence of any benefits from a carbon trading regime, our costs estimates translate into a cost of between US$2 and US$3 per tonne avoided after taking fiscal effects into account. Conversely, if a carbon trading regime applied and the carbon price yields revenues that are treated in the same way as revenues from gas sales,, the minimum carbon price required to justify CO_2 sequestration would be US$10 per tonne avoided.

Legislation and regulations

To our knowledge there are no regulations or legislation in South-East Asia that specifically cover CO_2 transport and storage as a separate identifiable activity. Such regulations and legislation would need to be developed before these projects could proceed on a significant scale. Existing environmental legislation, the need to commission environmental impact statements and existing oil and gas regulations all might affect CO_2 transport and storage. However, this might be by accident rather than design and it is likely that CO_2 transport and storage would need to be expressly prescribed in such legislative and regulatory systems.

Some economies offer incentives for environmental management that might be relevant to and assist CO_2 transport and storage. For instance, in Malaysia there are incentives in the form of tax allowances for companies that treat and dispose of toxic and hazardous wastes by acceptable methods. Such incentives could be extended to include CO_2 storage.

To our knowledge, many of the CCS environmental issues (such as log-term liability for CO_2, surface rights, measuring, monitoring and verification requirements) that are being actively discussed in the USA, Canada, Australia and other economies are not given equivalent levels of attention in South-East Asia.

Conclusions and recommendations

The results of this study suggest that, depending on any future carbon price and fiscal policies, there is significant potential for transport and injection of CO_2 emitted from natural gas field developments in South-East Asia. A significant number of projects are likely to be viable with a carbon price up to US$20 per tonne in real terms ignoring the effects of the fiscal terms that operate across the region and up to US$60 per tonne in real terms assuming that the fiscal terms that apply to gas field developments also apply to CO_2 transport and injection.

However, this study is based on limited high-level data and therefore the findings are only broadly indicative. More detailed project-specific studies are required. In addition, realising the potential for CO_2 sequestration requires more work in establishing the economic, fiscal and regulatory environment in which such projects could be developed.

We recommend further study based on more specific data on actual gas field developments and potential storage sites, particularly depleted or depleting fields for which data is plentiful. Depending on the circumstances, this might involve a study of enhanced oil or gas recovery in addition to CO_2 storage. In our view, such a study would first require obtaining the cooperation of oil and gas companies in the region and then working closely with them. The study is likely to proceed in stages. First it would involve contacting companies at a high level to gauge their level of interest in collaborating in such a study. Then it would involve negotiating agreements with interested companies to determine the terms of reference before the study begins. Finally, it would involve preparing the study with the close cooperation of the interested companies.

Table of contents

List of figures

List of tables

List of abbreviations

°API	American Petroleum Institute (API) gravity
°C	degrees Celsius
APEC	Asia Pacific Economic Co-operation
APPEA	Australian Petroleum Production and Exploration Association Ltd
B.	Basin
bbl	barrel (= 0.158987294929 m^3)
BOPD	barrel of oil per day
Btu	British thermal unit (= 1,055.05585 joules)
C.	Central
C_2H_6	Ethane
cf or scf	standard cubic foot (= 0.028316846592 m^3)
CH_4	methane
CO_2	carbon dioxide
CO_2-e	carbon dioxide equivalent (= mass of gas × GWP of gas)
CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies
d	day
D	darcy (= 0.9869233 μm^2)
DMO	Domestic Market Obligation
E.	East
EGR	enhanced gas recovery
EOR	enhanced oil recovery
Fm	formation
FTP	First Tranche Petroleum
Gp	group
GTL	gas to liquids
GWP	global warming potential
hr	hour
IEA	International Energy Agency
IEA GHG	IEA Greenhouse Gas Research and Development Programme
IFT	interfacial tension
J	joule
kg	kilogram
LNG	liquid natural gas
m, m^2, m^3	metre, square metre, cubic metre (Nm^3 = standard cubic metre)
MMP	minimum miscibility pressure
mol	mole

N.	North or Northern
NPV	net present value
P	poise (= 0.001 Pa.s)
Pa	pascal
P_{res}	reservoir pressure
PSC	production sharing contract
PV	present value
RKB	rig kelly bushing
S.	South
Sst	Sandstone
t	tonne (= 1000 kg)
T	temperature
UNSW	The University of New South Wales
vol%	percent volumetric concentration
W	watt
W.	West
WAG	water-alternating-gas
yr	year

Unit prefixes

SI and metric

Symbol	Multiple	Prefix
µ	10^{-6}	micro-
m	10^{-3}	milli-
c	10^{-2}	centi-
k	10^{3}	kilo-
M	10^{6}	mega-
G	10^{9}	giga-
T	10^{12}	tera-

Customary

Symbol	Multiple	Prefix
M	10^{3}	thousand
MM	10^{6}	million
B	10^{9}	billion
T	10^{12}	trillion

1 Introduction

Asia-Pacific Economic Cooperation (APEC), through the Expert Group on Clean Fossil Energy of the Energy Working Group, has contracted[2] CO2CRC Technologies Pty Ltd (CO2TECH) to prepare a study containing an assessment of the potential for reducing carbon dioxide (CO_2) emissions from natural gas production in South-East Asia through carbon capture and storage (CCS). CO2TECH is the commercial arm of the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC).

The full text of APEC's invitation to tender for the study is shown in Appendix 1.

1.1 Aims

The terms of reference for the APEC study include the following aims —

(c) “to assess the techno-economic feasibility of reducing CO_2 emissions resulting from natural gas production in South-East Asia through the application of CCS technologies, specifically by re-injecting the gas into subsurface geological formations”

and

(d) “a combination of promoting awareness, building capacity and developing human capital in the discovery of CCS.”

1.2 Scope

Based on these aims, the focus of our work is to estimate in broad terms -

(a) the costs of transporting and storing CO_2 from gas discoveries in South-East Asia, and

(b) the potential for CO_2 injection through enhanced oil recovery, enhanced gas recovery, conversion of natural gas and CO_2 mixtures to liquid hydrocarbon.

As part of the assessment, we also examine the possible effects on potential CO_2 transport and storage projects of the fiscal terms that currently apply to gas developments as well as potential regulatory issues associated with such projects.

We analyse only the transport and injection of CO_2 and not CO_2 separation (or "CO_2 capture") from the mixed gases extracted from the subsurface. Therefore, we do not analyse the entire natural gas development. We analyse only the additional costs of transporting and storing the produced CO_2.

We make detailed quantitative analyses of CO_2 injection into saline formations. We do not make equivalent analyses of enhanced oil or gas recovery. This approach is necessary because sufficiently detailed data on oil and gas discoveries in South-East Asia is not publicly available. However, our report includes a qualitative assessment of the potential for the application of these technologies.

We cover the following economies in our analyses and comments — Brunei, Indonesia, Malaysia, Papua New Guinea, Thailand and Vietnam. These economies are APEC members in South-East Asia, have natural gas production and, in some cases, natural gas production with significant associated CO_2 emissions.

Given the extensive geographical scope of the study, we do not attempt to analyse CO_2 transport and injection in detail. Our aim is to present broad indications of the economics of storing CO_2 emissions from gas developments in the South-East Asian region.

[2] Project EWG 06/2008A “Assessment of the Capture and Storage Potential of CO_2 Co-Produced with Natural Gas in South-East Asia”

1.3 Uncertainty

The estimates made for this study are subject to very large uncertainties, are based on scoping analyses and therefore are only indicative. They could change substantially over time as technologies, storage capacities, equipment costs and other variables change. They are based on rule-of-thumb techniques for estimating equipment sizes and the costs of individual items of equipment and associated services. More detailed and extensive feasibility studies, based on more data, need to be undertaken before investment in any CO_2 transport and injection project could be considered.

2 Existing CO_2 injection projects

In this section we describe the features of a selection of existing or planned projects involving the transport and storage of CO_2 co-produced with methane from gas discoveries across the world. We also describe the Weyburn-Midale project that uses CO_2 from a power station for enhanced oil recovery (CO_2 EOR). These demonstrate the practical feasibility of the technology and provide a setting for the study of possible equivalent projects in South-East Asia.

2.1 Sleipner

Statoil's Sleipner discovery in the Norwegian sector of the North Sea contained 6.3 Tcf of natural gas [1]. The discovery contains about 9% CO_2 which needs to be removed before the gas can be sold [2]. During the project's development phase, in 1991 the Norwegian government introduced an offshore CO_2 tax and so Statoil proposed to inject rather than emit the CO_2 [3]. This makes Sleipner the first commercial geological CO_2 storage project (see Figure 1). Since 1996, the project has been injecting about 1 Mt/yr of CO_2 into the Utsira Formation. Statoil estimates that there is sufficient structural closure within 12 km of the injection site to store 20 Mt of carbon dioxide over the life of the project [4].

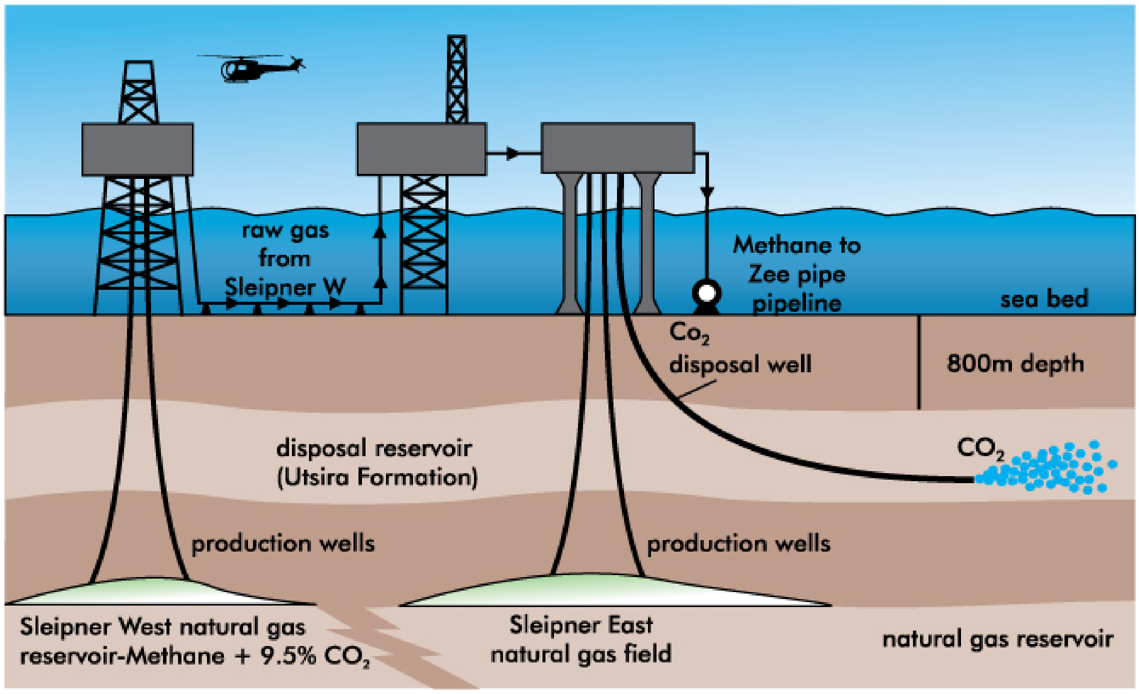


Figure 1 – A schematic depiction of the Sleipner Vest development [5]

The gas produced from the Ty formation is pre-treated before the CO_2 is removed and further treated on the Sleipner T platform. Most of the treated natural gas is exported through a pipeline to the European mainland. Some of the gas is reinjected into the Sleipner East discovery to improve condensate production [6].

The CO_2 is captured from the produced gas stream with a conventional amine process using Methyl diethanolamine (MDEA) as the solvent [7]. Before injection [8], CO_2 is converted to a supercritical state, requiring compression to 8 MPa and cooling to 40°C. This is achieved using a compressor train consisting of 4 units, each with a fluid knockout drum to remove water, compressor, cooler and gas turbine driver.

The recovered CO_2 is injected into the Utsira Formation, a 50 m-to-250 m thick sandstone unit approximately 1,000 m below the Sleipner discovery [8]. One horizontal injection well is used to inject 1 Mt of CO_2 per year into the storage reservoir [8]. The Utsira formation has very favourable geological characteristics. Permeabilities are in the range 1 to 10 Darcy and porosities are greater than 30%. These properties, together with the sizeable net pay mean that injectivities in the Utsira formation are quite high. In practise, very few CO_2 storage formations would have such high injectivities.

There has been extensive monitoring of the project as part of the IEA Greenhouse Gas R&D Programme's (IEA GHG) Saline Aquifer CO_2 Storage (SACS) project [4]. The *SACS Best Practice Manual* [6] reports the results of seismic surveys of the Utsira formation over the period 1994 to 2001. Again, because of the particular characteristics of the Utsira formation, the images produced show the location of injected CO_2 in very clear bands.

2.2 Snøhvit

The Snøhvit project, operated by Statoil, is the first offshore development in the Barents Sea [9]. Located at 70° North, the project makes extensive use of subsea production facilities with no surface facilities offshore. The gas produced in almost 300 m of water is tied back 143 km to producing facilities at Melkøya [10]. The Snøhvit development will eventually incorporate gas from three discoveries (Snøhvit, Albatross and Askeladd). The development has reserves of 6.8 Tcf of natural gas and approximately 113 million barrels of condensate.

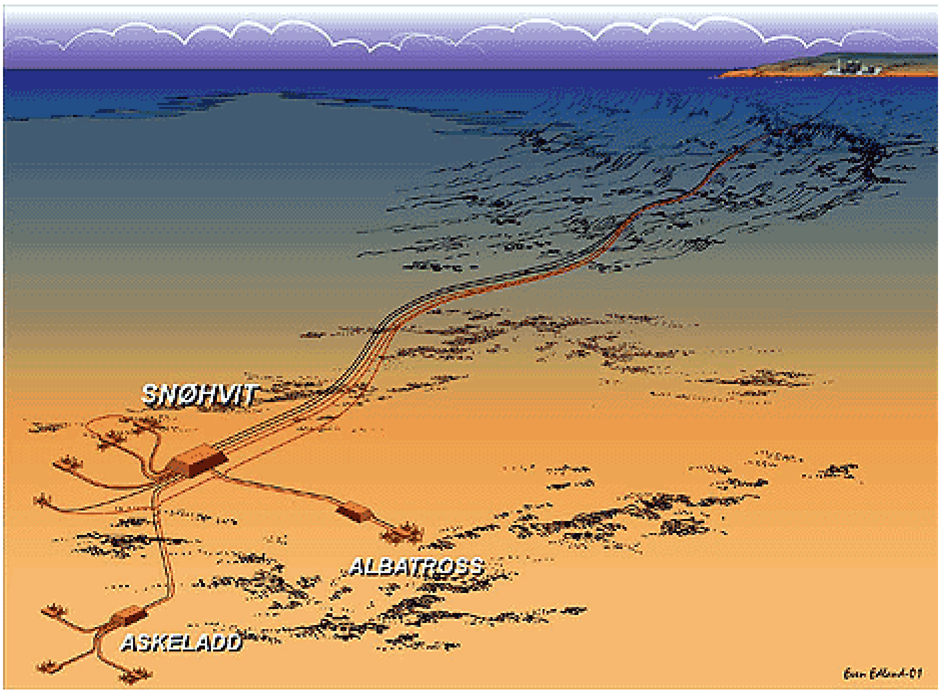


Figure 2 – An artist's impression of the offshore component of the Snøhvit project [12]

Source: Offshore-technology.com, "Snøhvit Gas Field, Barents Sea, Norway"
http://www.offshore-technology.com/projects/snohvit/

The gas produced from the Snøhvit discovery is converted to LNG for sale into the US market. Since the produced gas contains up to 8% CO_2 it undergoes treatment in a high pressure amine based solvent absorption process that reduces CO_2 content to the levels required for making LNG [11].

The CO_2 captured as part of the LNG process is compressed to a liquid state for transport back to the Snøhvit discovery where it is injected into the Tubåen formation 2,600 m below the sea bed [14].

The Tubåen formation is overlain by a shale layer that will trap injected CO_2. The CO_2 injection process will sequester at most 0.7 Mt/yr.

2.3 In Salah

The In Salah gas development in the central Sahara region of Algeria is a joint venture between BP, Statoil and the Algerian national oil company, Sonatrach. The development involves producing, treating and exporting gas from seven dry gas fields in the Ahnet-Timimoun Basin. The development is estimated to contain about 12 Tcf of natural gas reserves and has a CO_2 content of between 8% and 10%. The first gas was produced in 2004 and the system has a capacity to produce up to 320 Bcf/yr [13].

The gas is produced from the Krechba formation and the CO_2 is removed by a conventional solvent absorption system. The gas is dehydrated and then exported through a pipeline to the European market. A schematic of the project is shown in Figure 3.

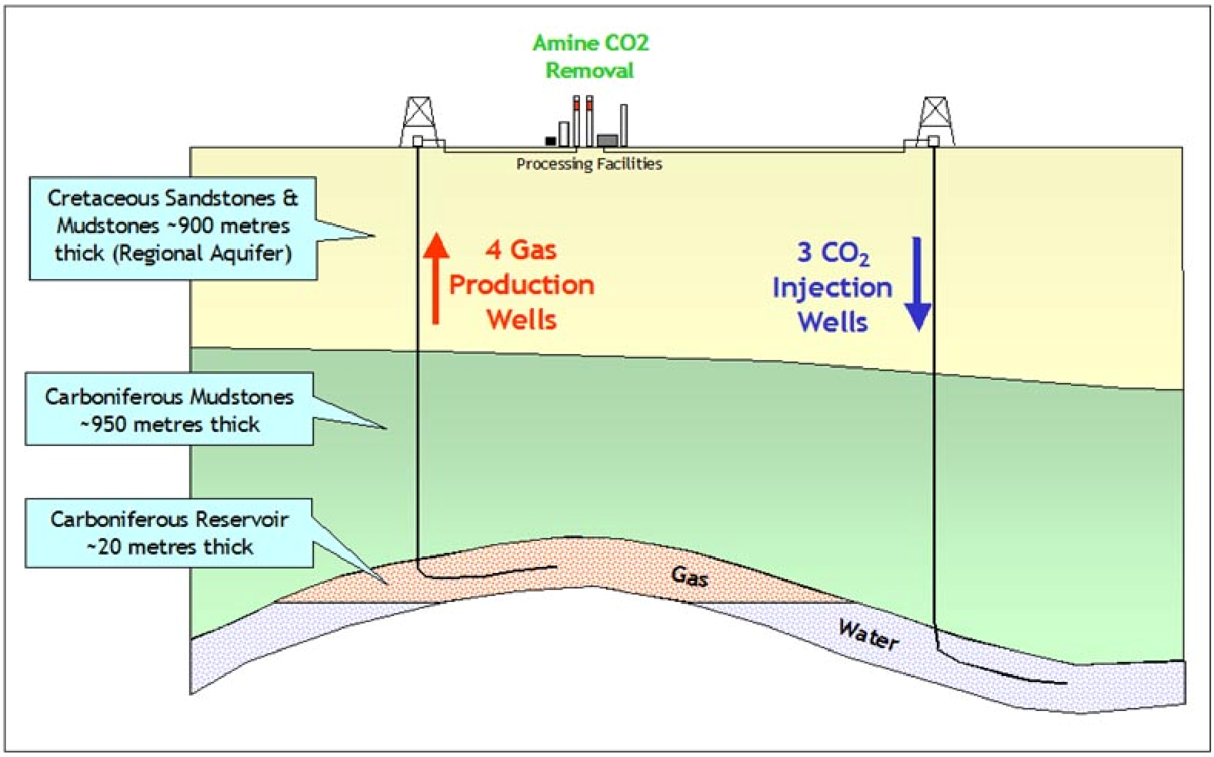


Figure 3 – Gas production and CO_2 reinjection for the In Salah development [15]

Source: Wright, I., (2006). CO_2 Geological Storage: Lesson Learned from In Salah (Algeria), In: *Proceedings of the First International Conference on the Clean Development Mechanism*, Riyadh, Saudi Arabia, 19–21 September 2006.

The captured CO_2 is compressed and dehydrated before being injected through three 1.2 km long horizontal wells back into the gas bearing Krechba formation. Since 2004, the injection rate of CO_2 has averaged about 1 Mt/yr and the project is expected to store up to 17 Mt [16].

As well as standard monitoring techniques such as seismic surveys, the In Salah project has also used satellites to measure ground deformation [17]. This remote-sensing approach has shown a 30 mm rise is surface elevation around the injectors and subsidence near the producers. This technique has also confirmed that the CO_2 is moving in the expected directions.

2.4 Weyburn-Midale

The Weyburn oilfield in the Williston Basin of Canada was discovered in 1954. The field covers an area of some 210 km² and has a current oil production rate of about 29,700 bbl/d of medium-gravity crude oil. The development includes 650 production wells and 289 injection wells [13, 18, 19].

From late 2000, Cenovus Energy (formerly EnCana) has been injecting significant amounts of CO_2 into the field to improve oil production. The gas is supplied through a 325 km long pipeline from the Dakota Gasification Company's Great Plains synfuels plant at Beleuah, North Dakota. The EOR aspect of the project is depicted in Figure 4. In 2005, Apache Canada implemented a similar CO_2 EOR scheme in the adjacent Midale oilfield.

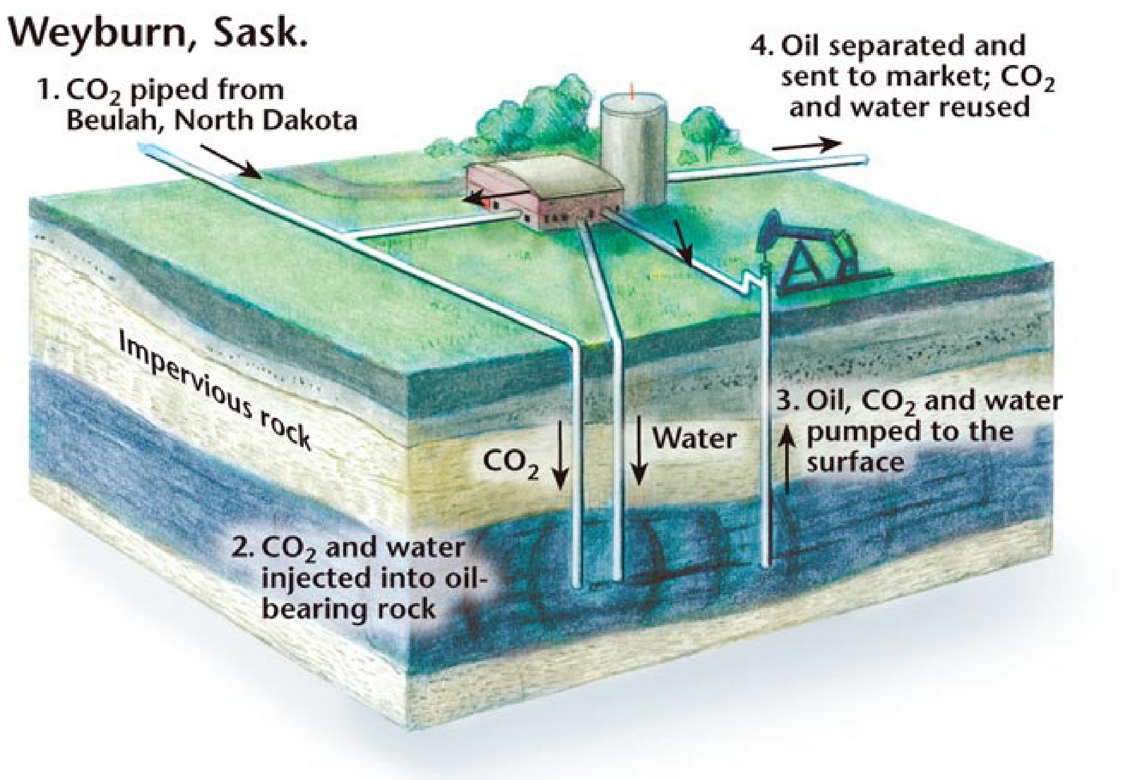


Figure 4 – Schematic of the Weyburn-Midale EOR project [20]

Source: Gagnon, S., C. Rea, A. McGuire, M. McBride Peterson, A. Casey and G. Gill, (2008). "In-depth: Burying the problem", *Canadian Geographic*, January/February issue 2008.

The two projects combined are injecting more than 2.8 Mt/yr, resulting in the production of an additional 25,000 bbl/d. Not all the CO_2 injected in an enhanced oil recovery (EOR) project remains in the subsurface. Some CO_2 reaches the production wells. Both operations include equipment to recycle CO_2 produced with the oil. Over the life of the projects, the operators envisage storing over 40 Mt of CO_2.

2.5 Gorgon

The Gorgon Project (see Figure 5) is being developed by Chevron Australia together with its joint venture partners Shell and ExxonMobil. With reserves estimated to be about 40 Tcf, the development has capacity to produce 15 Mt/yr of LNG and 300 TJ/d of natural gas from the Gorgon and Io-Jansz discoveries [21]. Each of the joint venture partners has negotiated separate sales agreements for its share of the produced gas [22]. The discoveries being produced by this project contain about 1.5 to 2.6 Tcf of carbon dioxide – the Gorgon discovery contains 14% CO_2 [23]. In order to avoid large-scale emissions to the atmosphere, the Gorgon project will store 3.3 Mt/yr of carbon dioxide in a saline formation below the Barrow Island processing facilities [24].

The project is expected to cost A$43 billion [24] with the CCS component costing between A$300 million and A$400 million [25].

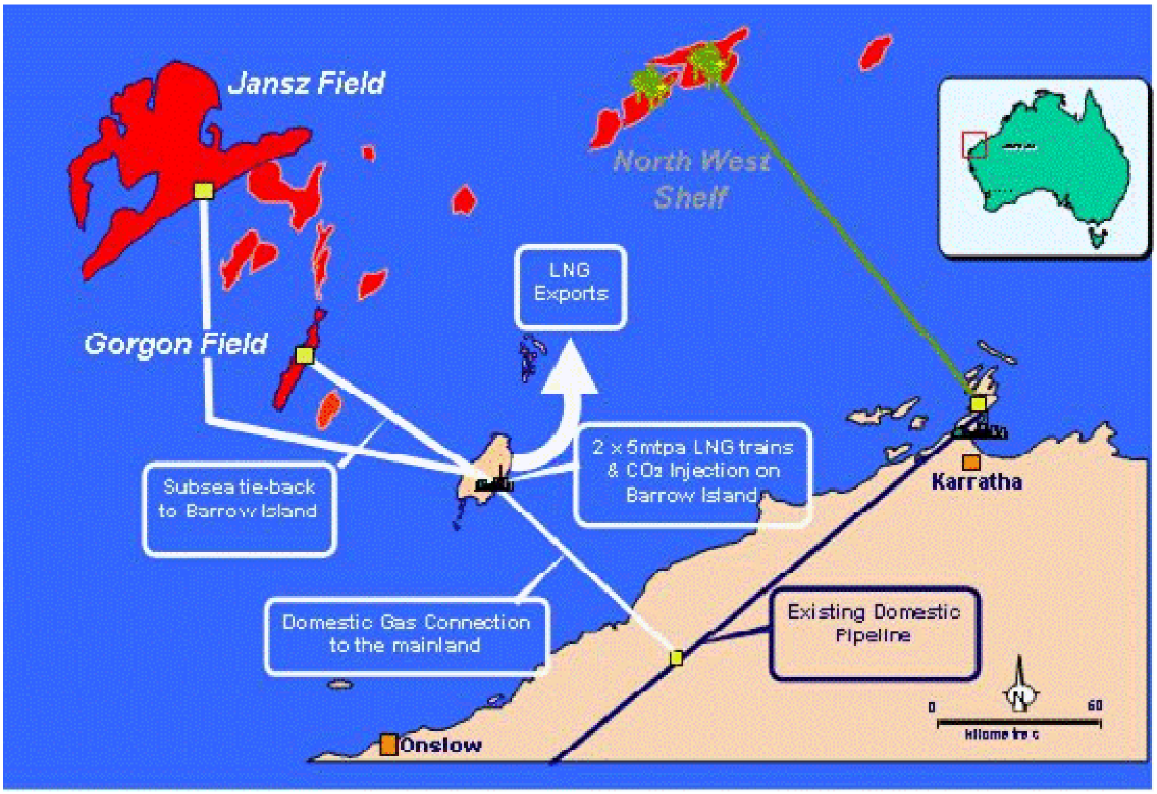


Figure 5 – A map of the Greater Gorgon development plan [23]

Source: Chevron, (2005). "The Gorgon Project" In: *Proceedings of the 2005 Annual CO2CRC Research Symposium*, Barossa Valley, Australia, November 2005.

The Gorgon discovery is in 200 m of water and Io-Jansz discovery is in 1,300 m around 130 km from the Australian mainland [25]. The discoveries will be produced by subsea completed wells and tied back to Barrow Island 70 km from the Australian mainland. The gas will be processed in three 5 Mt/yr LNG trains with some gas being exported to the domestic market [21].

The scale of CO_2 storage planned for the Gorgon project will make it the largest of its kind in the world. The project [8] will involve the reinjection of 2.7 to 3.2 Mt/yr CO_2 extracted from the discovery gas into the Dupuy Formation 2,300 m below Barrow Island. CO_2 will be separated from the produced gas at the gas-processing facility on the island, compressed to a supercritical state, and then transported by a 12 km pipeline to the injection site for storage. The development plan calls for approximately ten injection wells with additional monitoring and water relief wells. A total of 125 Mt CO_2 is expected to be stored over the life of the project.

2.6 Comparison

Each of the projects discussed above involve different development plans, operator preferences, geological and economic conditions. In comparing projects with each other and with the case studies in this report, it is important to keep these differences in mind. Table 1 highlights some of the differences between the projects discussed in this section.

Table 1 – Comparison of features of existing CO_2 injection projects

Project		Sleipner	Snøhvit	In Salah	Weyburn-Midale	Gorgon
Economy		Norway	Norway	Algeria	Canada	Australia
Basin		North Sea	Hammerfest	Ahnet-Timimoun	Williston	Barrow Sub-B.
Formation		Utsira	Tubåen	Krechba	Midale	Dupuy
CO_2 injection rate	Mt/yr	1	0.7	1	5.3(ii)	2.7 to 3.2
Number of wells		1 × 1,250 m perforated horizontal	1 vertical	3 × 1,000 m perforated horizontal	650 production & 289 injection	9 vertical
Water depth	m	?	300	0	0	0
Areal extent	km²	26,100	N/A	N/A	210	N/A
Fm thickness	m	50 to 250	45 to 75	20	3 to 27	350
Injection depth	m RKB	1,000	2,600	20	1,450	2,300
Porosity	%	Over 30%	10 to 16%	0.2	15% to 26%	15%
Permeability	mD	1,000 to 10,000	130 to 880	25	10 to 30	10
Fm temperature	°C	37	N/A	N/A	66	90
Fm pressure	MPa	9	28.5	17	13 to 17(iii)	19

(ii) This injection rate includes recycled CO_2
(iii) Minimum miscibility pressure

3 Storage technologies

The literature on carbon capture and storage discusses storage in saline formations, depleted oil and gas fields and coal seams (including enhanced methane recovery). It also discusses enhanced oil and gas recovery in conventional oil and gas reservoirs.

All the quantitative representative analyses in this report assume CO_2 storage in a subsurface reservoir with a given set of reservoir properties. They assume supercritical or subcritical CO_2 injection depending on the pressure regime of the transport and injection operation. The analyses implicitly assume injection sites with the reservoir properties assumed for the sedimentary basin where they are located.

The quantitative representative analyses of CO_2 transport and storage presented in this report rely solely on indicative data on the reservoir properties of sedimentary basins in South-East Asia. These are based on geological assessments, seismic surveys and oil and gas exploration and production drilling. This generalised basin data is not sufficiently detailed to allow us to distinguish between specific types of storage reservoir into which CO_2 might be injected.

Individual depleted or producing oil and gas fields are unlikely to have the same pressure regime as we assume applies to the sedimentary basin and we do not attempt to analyse depleted or producing fields in our representative cases.

We do not show quantitative analyses of CO_2 injection for enhanced oil or gas recovery.

The ability to inject CO_2 into the subsurface depends on many factors including the injection reservoir's permeability, porosity, areal extent, thickness, pressure and fracture pressure. The composition of the injected gas is also critical. In the representative analyses in this report, we assume that this is a mixture of CO_2, methane and other hydrocarbons. The composition reflects the composition of the raw gas at the source.

3.1 Storage in saline formations

Saline formations that are suitable for CO_2 storage are subsurface salt-water reservoirs overlain by relatively impervious sealing formations that effectively allow the CO_2 to be trapped permanently. Often the formations are sufficiently deep (usually over 800 metres) that the pressure in them is high enough to maintain the injected CO_2 in a very dense super-critical state. When CO_2 is in such a state, it is immiscible in water. The CO_2 is permanently stored in the formation by one or more of mechanisms, such as stratigraphic, structural, hydrodynamic and geochemical trapping mechanisms. These are described in the IPCC's "Special Report on Carbon Dioxide Capture and Storage" [26].

A feature of storage in saline formations, including those in South-East Asia, is that data on their reservoir characteristics is limited. This is typically because few wells have been drilled into them and seismic surveys have not targeted the subsurface structures. Very often the properties of saline formations have to be inferred from oil and gas reservoirs in the same sedimentary basins.

3.2 Storage in depleted oil and gas fields

Depleted oil and gas reservoirs are good candidates for CO_2 storage because their ability to trap fluids over millions of years has already been demonstrated. In addition, the geological structure and reservoir properties have usually been studied extensively. Injecting CO_2 into such reservoirs can also be aided by the fact that some of the infrastructure is already in place. However, the integrity of existing abandoned wells will need to be demonstrated with the wells repaired, if necessary.

The pressure regime of depleted oil and gas fields is likely to be very different to that of saline formations and this could significantly affect the design of the transport and injection system.

3.3 Enhanced oil recovery

Enhanced oil recovery (EOR) through injecting CO_2 into oil reservoirs (CO_2 EOR) is an established technique and has been used in the petroleum industry for almost four decades. A survey published by the Oil and Gas Journal in 2008 [27] showed that there were 123 CO_2 injection projects worldwide, contributing an incremental oil recovery of approximately 270 thousand barrels per day. This represents less than 0.5% of total crude oil production. However, enhanced oil production through CO_2 flooding has increased steadily.

The motivation for almost all CO_2 injection projects is to enhance oil recovery, not to reduce CO_2 emissions into the atmosphere. One of the major limitations of the EOR projects is the cost of CO_2. Most CO_2 injection projects have used naturally occurring CO_2 which has been transported from distant sources through pipelines. If the availability of injection gas at low enough cost is made possible, either because the cost of capture was reduced or because incentives for CO_2 storage were in place, many more oil reservoirs would be candidates for CO_2 injection. Recent estimates by Kinder Morgan show that about 650 Mt of CO_2 have been injected in EOR projects over the past 4 decades, which is an average of approximately 18 Mt/yr. This is approximately equivalent to the CO_2 emissions from five 500 MW capacity coal-fired power plants.

A combination of CO_2 EOR with underground disposal of CO_2 is a co-optimisation problem which involves maximizing both incremental oil recovery and CO_2 storage. Co-optimisation is relatively new to the industry and needs further research.

3.3.1 CO_2 EOR mechanisms

There are two mechanisms by which CO_2 EOR can enhance recovery — miscible flooding and immiscible flooding.

3.3.1.1 Miscible flooding

In a miscible flood, or, more accurately, multi-contact miscible flood project, the miscibility between CO_2 and oil is the main mechanism that improves oil recovery. Miscibility affects the phase behavior of CO_2 at subsurface pressure and temperature during and after injection. It must be understood thoroughly for a proper assessment of incremental oil recovery and CO_2 storage. At the reservoir pressure and temperature above the critical point for CO_2 (7.38 MPa and 31.1°C), which can be achieved at reservoir depths above 800 m, CO_2 density becomes very similar to oil and water densities. However, the viscosity of CO_2 remains lower than the viscosities of oil and water. This may lead to a viscous unstable flood which may weaken the sweep efficiency and hence recovery factor.

When the reservoir pressure is near or above the minimum miscibility pressure (MMP), CO_2 can displace oil quite efficiently in the invaded zones of the reservoir. The MMP depends on the reservoir temperature and the composition of the oil. It can be estimated by various methods such as slim tube experiments, semi-analytical and analytical methods. For example, the following expression can be used to calculate the MMP in MPa [28] –

$$MMP=0.1 \cdot exp\left(-\frac{2,015}{273.15+T}+10.91\right) \quad (1)$$

This pressure is most accurate for light oils at temperatures (T) below 50°C. It also is a useful parameter for assessing CO_2 sequestration because the efficient use of the pore space requires that relatively dense CO_2 be stored.

3.3.1.2 Immiscible flooding

In an immiscible flood, the CO_2 EOR mechanism may be different. In immiscible flooding, CO_2 displacements are usually more efficient than nitrogen and methane displacements. Even at the pressures below the MMP where the flood is immiscible, CO_2 flooding occurs in low-to-medium interfacial tension zones. In these cases, CO_2 can be injected up-dip in a gravity drainage mode to displace oil more efficiently towards the producing wells located down-dip.

3.3.2 Numerical simulation

For both miscible and immiscible floods, the CO_2 EOR process must be simulated numerically over a scale of meters to kilometres in order to estimate the lateral extent of the CO_2 plume in subsurface. The phase behaviour of the CO_2-oil-water system and pore-scale physics are important elements of simulating the behaviour of CO_2 EOR. The former assesses the mass interactions between the phases while the latter helps to assess the displacement efficiency.

3.3.3 Fluid movement

CO_2 can be stored in those zones in which CO_2 replaces reservoir oil or water. CO_2 is soluble in water and it is approximately 10 times more soluble in oil. The movement of oil and gas in a reservoir is dominated by the pressure gradient created between injection and production wells and by the heterogeneity of the rocks. The viscosity of CO_2 is low compared with that of the oil and water in the reservoir. The injected CO_2 invades high-permeability flow paths as it makes its way to production wells. A detailed description of the permeability distribution in the reservoir is required to obtain accurate predictions of (a) when the injected CO_2 breaks through to the production wells and (b) the amount of CO_2 produced with the oil. Those predictions forecast the amount of subsequent production, recompression, and recycling of CO_2 that is produced with oil. In virtually all CO_2 EOR projects, large volumes of CO_2 are recycled.

3.3.4 Options

The local availability of CO_2 and its cost are two important economic criteria which need to be considered in screening reservoirs for CO_2 EOR. If the objective is also to increase storage of CO_2, then changing injection horizons, injecting CO_2 into a saline formation below the reservoir, or injection into the capillary transition zone may also be useful. While many of the specific actions taken to increase CO_2 storage will depend on the details of the particular reservoir setting, it is apparent that many opportunities exist for developing the design of CO_2-injection projects in a way that increases storage substantially over the amounts stored in secondary EOR projects. For example, modifications of the commonly used water-alternating-gas ("WAG") injection schemes may allow greater CO_2 storage while at the same time controlling the cycling of injected CO_2.

3.3.5 Screening reservoirs for CO_2 EOR and CO_2 storage

Screening criteria for oil reservoirs that might be candidates for incremental oil and CO_2 storage through CO_2 injection have been suggested by several authors [28–30]. The MMP required for a given oil increases with temperature because at higher temperatures the density of CO_2 and its solubility in oil decreases. Since the reservoir temperature increases with depth, so does the MMP (see Equation (1)).

However, the fracture pressure of the reservoirs increases much faster than temperature so there is an MMP “window of opportunity”. Oils heavier than 40°API would have an MMP/temperature/depth correlation above the line. A depth of greater than 760 m is more appropriate for CO_2 EOR projects. Most of the relationships between temperature, oil composition and pressure come from extensive work on oils from U.S. discoveries such as those from the Permian basin of West Texas and southeast New Mexico. Therefore, the oils that differ from these require more study. Hagedorn and Orr [31] showed that a high percentage of multi-ring aromatics will raise the MMP significantly because they are extracted so poorly by CO_2. Taber suggested that incremental oil recovery would increase when the composition of the crude has a high percentage of C_5 to C_{12}, when the quality is 22°API or greater, when the viscosity is 10 cP or lower and when the oil saturation is 20% or more. Hagedorn and Orr do not consider permeability to be a critical factor affecting incremental oil recovery.

Shaw and Bachu [32] present an analytical methodology for screening reservoirs for both incremental oil recovery and CO_2 storage. We adapt their methodology and screen the basins in Asia-Pacific based on the P_{res}/MMP ratio, net thickness, permeability and porosity. Given the lack of data of the oil properties, we exclude API gravity and initial oil saturation, which also play important role in screening. We weight the parameters, the P_{res}/MMP ratio, gross thickness and permeability the same. They are also significant, whereas the porosity is less significant.

Equation (1) was used to estimate MMP and results are given in Table 2. The results show that the first three formations are suitable for CO_2 EOR based on their favourable gross thickness and permeability, although their pressures are estimated to be below the MMP.

The relative importance of the different parameters (the relative weighting) is based on a subjective assessment. Different subjective assessments will yield different rankings. In addition, more data, especially describing oil properties, will refine the ranking.

The potential for CO_2 EOR is very case-specific and requires detailed data on individual oil reservoirs. We do not have sufficient data to carry out a detailed assessment of the potential for CO_2 EOR in individual reservoirs across the basins covered in this study.

A detailed analysis of the scope for enhanced oil recovery from individual oil fields in South-East Asia is beyond the scope of this study. As shown above, CO_2 EOR is likely to have application in particular circumstances where (a) CO_2 is readily available at an appropriate price, (b) reservoir conditions are suitable and (c) the fields are on decline. In other words, many conditions must be met at the same time to ensure a viable CO_2 EOR project. While there might be several suitable candidates for CO_2 EOR, they might not increase overall oil production in South-East Asia significantly and might not require significant volumes of CO_2.

From the perspective of reducing CO_2 emissions, enhanced oil recovery is not strictly comparable to CO_2 storage in saline formations or depleted oil or gas fields. Enhanced recovery produces additional hydrocarbons, which are ultimately burned and therefore cause additional CO_2 emissions unless those emissions are captured and stored.

Table 2 – Ranking of storage formations for CO_2 EOR

Formation	Basin	Economy	P_{res}/MMP ratio	Gross Thickness (m)	Permeability (mD)	Porosity (%)	Rank (iv)
H Group	Malay B.	Malaysia & Vietnam	0.85	200	800	30	1
Talang Akar Fm	N.W. Java B.	Indonesia	0.87	150	1,000	30	2
Batu Raja Fm	N.W. Java B.	Indonesia	0.80	300	1,000	30	3
D, E, F & G Group	Malay B.	Malaysia	1.09	300	100	25	4
Terumbu Fm	E. Natuna B.	Indonesia	0.78	800	250	24	5
Cycle V	Baram Delta B.	Brunei	1.67	50	980	20	6
Nam Con Son Fm	Nam Con Son B.	Vietnam	0.87	424	150	20	7
Peutu Fm	N. Sumatra B.	Indonesia	0.75	152	400	18	8
Pattani Trough	G. of Thailand B.	Thailand	0.66	1,650	500	21	9
Miocene Delta Sst	Kutei B.	Indonesia	1.27	21	1,000	28	10
Lower Kembelangan Gp	Bintuni B.	Indonesia	1.1	50	250	12	11
Sihapas Gp Sst	C. Sumatra B.	Indonesia	0.71	76	1,000	25	12
J Group	Malay B.	Vietnam	0.72	300	100	20	13
I Group	Malay B.	Vietnam	0.69	300	100	28	14
K Group	Malay B.	Malaysia & Vietnam	0.66	50	400	20	15
L Group	Malay B.	Vietnam	0.60	50	400	20	16
Pematang Fm	C. Sumatra B.	Indonesia	0.71	76	50	18	17

Optimum value			1.3	200	300	20
Worst value			0.6	10	1	1
Weighting (v)			0.3	0.3	0.3	0.1

(iv) Approximate ranking using rock properties only. The best formation has a rank of 1.
(v) The weights are based on a subjective assessment of relative importance.

3.4 Enhanced gas recovery

CO_2 injection into natural gas (predominantly methane) reservoirs has been proposed but not attempted. However, research suggests that injecting CO_2 into mature natural gas reservoirs for enhanced gas recovery and CO_2 storage is feasible [28, 33]. The average recovery of natural gas from gas discoveries worldwide is approximately 75% of the original gas-in-place in the reservoir. Of the original gas in place, water-drive gas reservoirs trap almost 35% of the original gas in place, while the depletion-drive reservoirs trap about 15%. These trapped volumes of natural gas are the potential targets for enhanced gas recovery using CO_2 injection (CO_2 EGR). In addition, for high CO_2 content gas reservoirs, the requirement to purify the sales gas to meet sales specifications offers an opportunity for carbon capture and storage. The In Salah and Gorgon projects are good examples of this.

CO_2 EGR mechanisms include CO_2-methane mixing, displacing methane with CO_2 and pressurising the reservoir. CO_2 is more viscous and dense than methane, but well-to-well flow will still be dominated by reservoir heterogeneity. In reservoirs with good vertical communication, it might be possible to take advantage of the higher density of CO_2 to design injection strategies and well completions that place CO_2 low in the reservoir, with production taken from the top. Methane and CO_2 need to be separated when the injected CO_2 breaks through into the natural gas stream. Slower diffusional mixing also may be a concern in long-life projects, although diffusion is very slow compared to typical reservoir-flow velocities. However, in reservoirs that have experienced a pressure decline before CO_2 injection starts, CO_2 injection for storage can continue after reservoir pressure maintenance has ended. This is the case provided proper attention is paid to the accompanying stress changes and their effects on seal integrity.

CO_2 storage in a gas reservoir would have the advantage that all CO_2 from oxidising the methane produced from the reservoir could be stored in the same reservoir, at the same temperature and pressure, with additional volume available for storage of more CO_2. One mole of CO_2 is produced for each mole of methane oxidized. Furthermore, the molar density of CO_2 is larger than that of methane at a given temperature and pressure.

The higher molar density of CO_2 means that the volume of methane produced from a gas reservoir could be replaced by a mixture of nitrogen and CO_2. For example, matching injection and withdrawal volumes would not require separating all the nitrogen from a flue gas. However, compared to the costs of compressing and transporting CO_2 alone, there would be an additional cost associated with the nitrogen/CO_2 mixture.

In discoveries that contain some condensate saturation, CO_2 can vaporise quite efficiently the light hydrocarbons that make up the condensate. It is also possible for CO_2 to develop multi-contact miscibility with two-phase gas and condensate mixtures [28]. If CO_2 capture and storage becomes widespread, gas reservoirs would be candidates for permanent CO_2 storage.

We are not aware of any projects in South-East Asia or world-wide in which the primary purpose of CO_2 injection is to improve natural gas recovery (CO_2 EGR). CO_2 injection and storage in saline formations beneath gas reservoirs might have an additional advantage in enhancing gas recovery. However, the study of CO_2 EGR is still in its early stages and it is difficult to assess its potential at the present time.

From the perspective of reducing CO_2 emissions, enhanced gas recovery is not strictly comparable to CO_2 storage in saline formations or depleted oil or gas fields. Enhanced recovery produces additional hydrocarbons, which are ultimately burned and therefore cause additional CO_2 emissions unless they are captured and stored.

3.5 Gas-to-liquids conversion

One future means of processing the CO_2 produced from high-CO_2 gas discoveries is to convert the raw gas stream into synthetic crude oil (“syncrude”) in a “gas-to-liquids” (“GTL”) process. Syncrude is essentially light crude oil that can be upgraded into naphtha, kerosene and diesel. One new version of GTL technology reforms methane with CO_2 and steam to produce “syngas” (carbon monoxide and hydrogen). The technology can be applied to the development of high-CO_2 gas fields [34] and so a brief review of its potential is appropriate for this report.

The syngas produced by the CO_2/steam reforming process is converted into syncrude in a Fischer-Tropsch process. The process is made possible by proprietary and special noble metal catalysts. The produced syncrude is upgraded by conventional refinery processes into common refinery products (naphtha, kerosene, and diesel).

A review of the process initially suggested that CO_2 emissions from high-CO_2 gas developments might be significantly reduced. The process does not require the CO_2 to be removed from the feed gas. The CO_2 contained in the raw gas potentially can be converted to GTL products. Instead of reforming methane with oxygen and steam, as in conventional GTL processes, the required syngas is made by reacting the CO_2 component of the raw gas with the methane component in the presence of steam.

Further review of the published technical information [35] shows that when there is 40% CO_2 in the raw gas feed, only 66% of the carbon entering the plant is transferred to the GTL products sold to the customer. For an equivalent LNG production option, 51% of the carbon is transferred to the customer in the LNG product. Therefore, not all the carbon is transferred to the customer. The loss of carbon mass across the process manifests itself as CO_2 emissions. If a hypothetical future technology enabled close to 100% conversion of feed carbon content (produced by reforming methane with CO_2 and steam) into syncrude, then CO_2 emissions would be almost eliminated from the production facilities of high-CO_2 gas discoveries.

Our simple analyses suggest that CO_2 emissions from this CO_2/steam reforming GTL process are 15% lower than from an LNG plant of the same capacity that requires the total removal of CO_2 from the raw high-CO_2 gas prior to liquefying the methane. However, the GTL process inevitably emits CO_2 which must either be emitted to the atmosphere (or subsequently captured and stored).

Appendix 2 shows our analysis of the published GTL process assuming that the CO_2 is 40% of the raw gas by volume.

From the perspective of reducing CO_2 emissions, GTL production cannot be compared to CO_2 storage in saline formations or depleted oil or gas fields. GTL basically converts hydrocarbons into different energy forms, namely liquids. The liquids are ultimately burned and therefore cause CO_2 emissions unless they are captured and stored.

4 Representative case analyses

A key component of the study is to assess representative the costs of transport and storage CO_2 emissions from natural gas developments. The representative analyses illustrate the costs of injection into saline formations. A separate section discusses individual case examples based on particular projects.

4.1 Methodology

For the representative cases we estimate the equipment sizes, the capital, operating and decommissioning costs, as well as the costs per tonne of CO_2-e avoided for CO_2 transport and injection. The costs are presented in US$2010 terms. They are based on limited cost and reservoir data and have a large margin of error. This reflects the high degree of uncertainty in estimating injection reservoir characteristics and unit costs.

We estimate the costs of the transport and injection projects both excluding and including potential fiscal effects. In this section we examine the economics excluding fiscal effect. The following section shows the effects of fiscal terms.

We have modelled only transport and injection economics and have not modelled the economics of capture or the sources emitting the CO_2. We have not carried out detailed assessments of enhanced oil recovery or enhanced gas recovery economics.

The main methods used for the analyses are listed and discussed below.

1. We assume for the representative cases (but not necessarily for the specific cases studies discussed in Section 6) that the methane being produced from the formations under consideration is delivered to the market as sales gas (not LNG). We assume that moderate levels of CO_2 are acceptable in the sales gas (e.g. 15%) and that membranes are used to remove CO_2 from the raw gas. This means that the injection gas will be a mixture of CO_2, methane and other hydrocarbons.
2. The basis for the assumption above is an underlying premise that high CO_2 content gas discovery development economics will support only partial CO_2 separation using membranes. This reflects the costs of gas discovery construction and operation as well as prevailing natural gas producer prices. The premise follows what we understand to be typical practice across South-East Asia. This implies that in many cases more complete CO_2 separation using solvent absorption is not viable or is significantly less viable than separation using membranes.
3. For all but the two Central Sumatra Basin cases and the Kutei Basin case, the number of wells estimated on the basis of simple reservoir simulation studies (see below) leads to top-hole injection pressures that are above the critical pressure of CO_2. Therefore, for most cases the injection gas is compressed from ex-capture conditions (2.5 MPa, 25°C) to a sufficiently high pressure (at least 8 MPa) to keep it in a supercritical state throughout the transport and injection process.
4. For the Central Sumatra Basin cases and the Kutei Basin case we compress it to at least 4 MPa rather than 8 MPa. This means that the injected gas remains in a subcritical state.
5. For the purposes of this analysis we assume that the ratio between methane and other hydrocarbons (namely ethane) is 4-to-1. The assumed content and composition of the discoveries are given in Table 3.

Table 3 – Assumed content and composition of individual representative natural gas fields with high CO_2 content for base cases

Economy	Basin	Formation	Location	Resource (BCF)				Resource (Mt)				Fm composition (vol%)			
				Methane	Other H/C	CO_2	Total	Methane	Other H/C	CO_2	Total	Methane	Other H/C	CO_2	Total
Indonesia	Bintuni Basin	Lower Kembelangan Gp	Offshore	2,400	600	529	3,529	48	22	29	99	68%	17%	15%	100%
Indonesia	E. Natuna	Terumbu Fm	Offshore	24,000	6,000	70,000	100,000	476	224	3,820	4,520	24%	6%	70%	100%
Indonesia	N.W. Java Basin	Batu Raja Fm	Onshore	80	20	150	250	2	1	8	11	32%	8%	60%	100%
Indonesia	N.W. Java Basin	Talang Akar Fm	Onshore	24	6	120	150	0.5	0.2	7	7	16%	4%	80%	100%
Indonesia	N. Sumatra Basin	Oligocene Sst	Offshore	480	120	600	1,200	10	4	33	47	40%	10%	50%	100%
Indonesia	N. Sumatra Basin	Peutu Fm	Onshore	4,000	1,000	2,143	7,143	79	37	117	234	56%	14%	30%	100%
Indonesia	C. Sumatra Basin	Sihapas Gp Sst	Onshore	240	60	75	375	5	2	4	11	64%	16%	20%	100%
Indonesia	C. Sumatra Basin	Pematang Fm	Onshore	240	60	75	375	5	2	4	11	64%	16%	20%	100%
Indonesia	S. Sumatra Basin	Talang Akar Fm	Onshore	112	28	115	255	2	1	6	10	44%	11%	45%	100%
Indonesia	Kutei Basin	Miocene Delta Sst	Onshore	1,200	300	375	1,875	24	11	20	55	64%	16%	20%	100%
Malaysia	Malay Basin	D Group	Offshore	640	160	343	1,143	13	6	19	37	56%	14%	30%	100%
Malaysia	Malay Basin	E Group	Offshore	1,200	300	808	2,308	24	11	44	79	52%	13%	35%	100%
Malaysia / Vietnam	Malay Basin	H Group	Offshore	240	60	450	750	5	2	25	32	32%	8%	60%	100%
Malaysia / Vietnam	Malay Basin	K Group	Offshore	240	60	450	750	5	2	25	32	32%	8%	60%	100%
Vietnam	Malay Basin	I Group	Offshore	240	60	450	750	5	2	25	32	32%	8%	60%	100%
Vietnam	Malay Basin	J Group	Offshore	240	60	450	750	5	2	25	32	32%	8%	60%	100%
Vietnam	Malay Basin	L Group	Offshore	240	60	450	750	5	2	25	32	32%	8%	60%	100%
Vietnam	Nam Con Son Basin	Nam Con Son Fm	Offshore	1,200	300	113	1,613	24	11	6	41	74%	19%	7%	100%
Thailand	G. of Thailand Basin	Pattani Trough	Offshore	1,520	380	633	2,533	30	14	35	79	60%	15%	25%	100%
Brunei	Baram Delta Basin	Cycle V	Offshore	2,000	500	10,000	12,500	40	19	546	604	16%	4%	80%	100%

6. We calculate the composition of the sales gas and injection gas using simple mass balances[3]. We make a preliminary optimisation of the mass balances by varying the CO_2 recovery rate and the sales gas CO_2 concentration to minimise the hydrocarbon loss-rate (the portion of the total hydrocarbons in the injection gas). We apply the following constraints —

   (a) The rate of CO_2 removal from the raw gas (removal rate) is less than or equal to 90%,

   (b) The concentration of CO_2 in the sales gas (sales gas CO_2 concentration) is between 0% and 20%, and

   (c) The volume of lost hydrocarbons is greater than zero.

   In calculating the flow-rate of the sales gas, we do not take into account gas used in producing power for the transport and injection process.

7. Figure 6 shows the results of the optimisation for the representative cases as a function of the concentration of CO_2 in the raw gas.

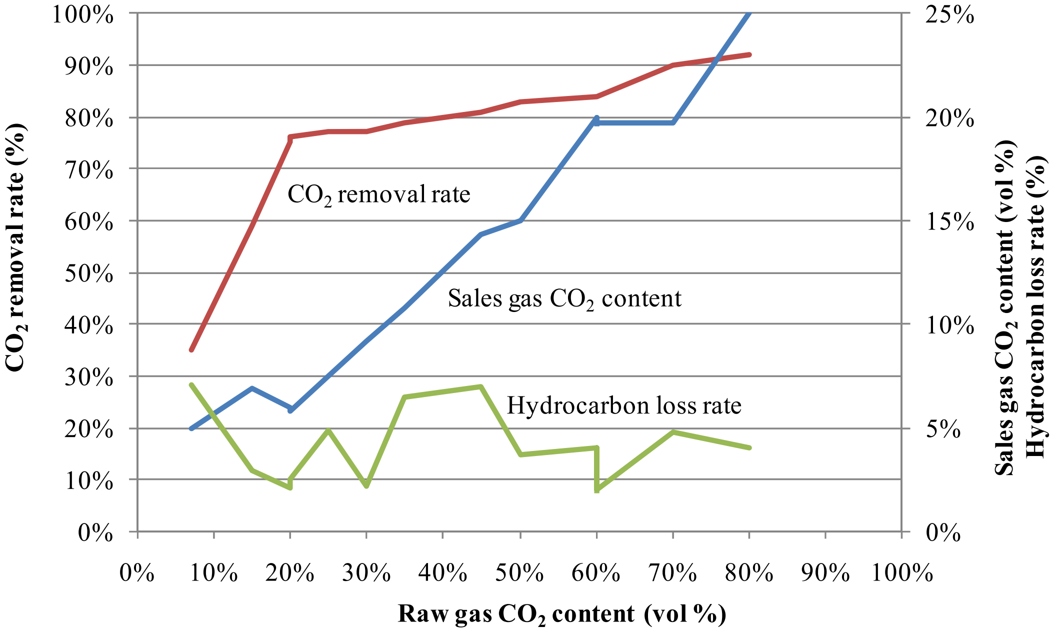


Figure 6 – Results of optimising sales and injection gas compositions as a function of raw gas composition

   Figure 6 shows that as the CO_2 content in the raw gas increases, the CO_2 removal rate has to increase in order to satisfy the sales gas constraint. This optimisation shows that high CO_2 removal rates are required even for moderate CO_2 concentrations (up to 20%) in the raw gas.

   For two cases (Talang Akar Fm in the N.W. Java Basin and Cycle V in the Baram Delta Basin) with 80% CO_2 in the raw gas, the optimisation cannot satisfy the constraints. For these cases, the constraints are relaxed and solutions are found with removal rates of 92% and sales gas CO_2 concentrations of 25 vol%.

   For all cases with CO_2 concentrations in the raw gas above 20%, it is likely that multi-stage separation would be required to achieve CO_2 concentrations in the sales gas of 5% or less. This condition would apply, for instance, when producing LNG.

8. Having determined the compositions and flow-rates of the sales and injection gas streams, we choose three sensitivity flow-rates. Each of these flow-rates is given in Table 4 together with the final values of the CO_2 removal rate, sales gas CO_2 concentration and hydrocarbon loss rate. The mass flow-rate

[3] The degree to which a membrane system will separate the different components of a feed stream is described in terms of its selectivity. Selectivity is the ratio of mole fractions in the injection gas divided by the ratio of mole fractions in the raw gas. We assumed a CO_2/CH_4 selectivity of 12 and a CO_2/C_2H_6 selectivity of 30.

for the raw gas, sales gas and injection gas streams are given in Table 5, while Table 6 shows the volumetric flow-rates for each stream. Finally, Table 7 gives the volumetric composition of each stream.

9. CO_2 avoided in transport and injection is the CO_2 injected less the CO_2 emitted in supplying energy to the compressors and auxiliary equipment required for transporting and injecting the CO_2. In our calculations of CO_2 avoided, we take into account only that CO_2 emitted as part of the transport and injection process. We do not take into account (a) those CO_2 emissions associated with supplying energy to capture the CO_2 and (b) the CO_2 not captured. This approach means that it is not valid to add the costs per tonne of CO_2 avoided in transport and injection as calculated in this report to the costs of CO_2 avoided in capture calculated separately.

   We also calculate the flow-rates of the produced gas (methane, CO_2 etc) and any injected gas (methane, CO_2 etc) in terms of their CO_2 equivalent (CO_2-e). The CO_2-e mass of methane is the mass of methane multiplied by its Global Warming Potential (GWP) as defined by the US Environmental Protection Agency. The 100 year GWP of methane and ethane are estimated at 25 and 5.5 respectively [36].

   We calculate the CO_2-e avoided using the following equation –

$$\begin{aligned} &CO_2\text{-}e\ avoided = \\ &\quad CO_2\text{-}e\ injected\ (methane,\ CO_2,\ etc.) \\ &\qquad less \\ &\quad CO_2\ emitted\ during\ transport\ and\ injection\ (no\ other\ gases\ are\ emitted) \end{aligned} \tag{2}$$

10. We assume that energy from a gas-fired generator is used to provide the additional energy for all transport and injection operations including compression and auxiliary equipment. The power plant does not have CO_2 capture facilities. The power plant, compressor and auxiliary equipment is assumed to require a separate fixed platform near the central processing platform.

11. We assume that a single compressor train occupies one unmanned platform. We assume that the compressors' service lives are between 25 to 30 years. Therefore they do not need replacing during the project's life.

12. The pipelines used to transport CO_2 are made from X70 carbon-steel line pipe. For onshore pipelines, we exclude the effects of terrain and land use on pipeline costs.

13. We have not included the cost of installing power transmission lines along the pipeline route to provide power for compression at the point of injection.

14. Vertical wells are used for injecting CO_2 into onshore storage formations. For offshore reservoirs we use deviated wells. For the representative cases we use our best estimate of well costs based on available cost data. For specific case studies, well costs were reviewed by the project operators.

Table 4 – Results of optimisation for individual representative discoveries together with mass flow-rates base and sensitivity cases

Economy	Basin	Formation	Location	CO_2 content (vol%)		CO_2 removal rate (%)	H/C loss rate (%)	Annual injection rates (Mt/yr)			
				Raw gas	Sales gas			Base	Sensitivity		
Indonesia	Bintuni B.	Lower Kembelangan Gp	Offshore	15%	7%	59%	3%	0.9	0.5	3.0	5.0
	E. Natuna B.	Terumbu Fm	Offshore	70%	20%	90%	5%	173	50	100	200
	N.W. Java B.	Batu Raja Fm	Onshore	60%	20%	84%	4%	0.3	0.1	0.5	1.0
		Talang Akar Fm	Onshore	80%	25%	92%	4%	0.3	0.1	0.5	1.0
	N. Sumatra B.	Oligocene Sst	Offshore	50%	15%	83%	4%	1.4	0.1	2.0	5.0
		Peutu Fm	Onshore	30%	9%	77%	2%	4.6	1.0	5.0	10
	C. Sumatra B.	Sihapas Gp Sst	Onshore	20%	6%	75%	2%	0.2	0.1	2.5	0.5
		Pematang Fm	Onshore	20%	6%	76%	2%	0.2	0.1	2.5	0.5
	S. Sumatra B.	Talang Akar Fm	Onshore	45%	14%	81%	7%	0.3	0.1	0.5	1.0
	Kutei B.	Miocene Delta Sst	Onshore	20%	6%	76%	2%	0.8	0.5	1.0	2.0
Malaysia	Malay B.	D Group	Offshore	30%	9%	77%	2%	0.7	0.5	1.0	2.0
Vietnam		E Group	Offshore	35%	11%	79%	7%	1.8	1.0	2.0	3.0
		H Group	Offshore	60%	20%	84%	4%	1.0	0.5	1.0	2.0
		K Group	Offshore	60%	20%	84%	2%	1.0	0.5	1.0	2.0
		I Group	Offshore	60%	20%	84%	4%	1.0	0.5	1.0	2.0
		J Group	Offshore	60%	20%	84%	4%	1.0	0.5	1.0	2.0
		L Group	Offshore	60%	20%	84%	2%	1.0	0.5	1.0	2.0
	Nam Con Son B.	Nam Con Son Fm	Offshore	7%	5%	35%	7%	0.2	0.1	0.5	1.0
Thailand	G. of Thailand B.	Pattani Trough	Offshore	25%	7%	77%	5%	1.4	0.5	2.0	10
Brunei	Baram Delta B.	Cycle V	Offshore	80%	25%	92%	4%	25	10	20	30

Table 5 – Volumetric flow-rates for the raw, sales and injection gas streams for individual representative high CO_2 content discoveries

Economy	Basin	Formation	Location	Raw gas flow-rate (MMscf/d)				Sales gas flow-rate (MMscf/d)				Injection gas flow-rate (MMscf/d)			
				Methane	Other H/C	CO_2	Total	Methane	Other H/C	CO_2	Total	Methane	Other H/C	CO_2	Total
Indonesia	Bintuni B.	Lower Kembelangan Gp	Offshore	339	85	75	498	328	84	31	442	11	1	44	56
Indonesia	E. Natuna B.	Terumbu Fm	Offshore	3,389	847	9,886	14,122	3,205	829	989	5,022	184	18	8,897	9,100
Indonesia	N.W. Java B.	Batu Raja Fm	Onshore	11	3	21	35	11	3	3	17	0.5	0.1	18	18
Indonesia	N.W. Java B.	Talang Akar Fm	Onshore	3	1	17	21	3	1	1	5	0.2	0.02	16	16
Indonesia	N. Sumatra B.	Oligocene Sst	Offshore	68	17	85	169	65	17	14	96	3	0.3	70	73
Indonesia	N. Sumatra B.	Peutu Fm	Onshore	565	141	303	1,009	551	140	70	760	14	1	233	248
Indonesia	C. Sumatra B.	Sihapas Gp Sst	Onshore	34	8	11	53	33	8	3	44	0.8	0.1	8	9
Indonesia	C. Sumatra B.	Pematang Fm	Onshore	34	8	11	53	33	8	3	44	1	0.1	8	9
Indonesia	S. Sumatra B.	Talang Akar Fm	Onshore	16	4	16	36	15	4	3	21	1	0.1	13	14
Indonesia	Kutei B.	Miocene Delta Sst	Onshore	169	42	53	265	165	42	13	219	5	0.5	40	46
Malaysia	Malay B.	D Group	Offshore	90	23	48	161	88	22	11	122	2	0.2	37	40
Malaysia	Malay B.	E Group	Offshore	169	42	114	326	157	41	24	222	13	1	90	104
Malaysia / Vietnam	Malay B.	H Group	Offshore	34	8	64	106	32	8	10	51	2	0.2	53	55
Malaysia / Vietnam	Malay B.	K Group	Offshore	34	8	64	106	33	8	10	52	0.8	0.1	53	54
Vietnam	Malay B.	I Group	Offshore	34	8	64	106	32	8	10	51	2	0.2	53	55
Vietnam	Malay B.	J Group	Offshore	34	8	64	106	32	8	10	51	2	0.2	53	55
Vietnam	Malay B.	L Group	Offshore	34	8	64	106	33	8	10	52	0.8	0.1	53	54
Vietnam	Nam Con Son B.	Nam Con Son Fm	Offshore	169	42	16	228	156	41	10	207	14	1	6	21
Thailand	G. of Thailand B.	Pattani Trough	Offshore	215	54	89	358	203	52	21	276	12	1	69	82
Brunei	Baram Delta B.	Cycle V	Offshore	282	71	1,412	1,765	270	69	113	452	13	1	1,299	1,313

Table 6 – Mass flow-rates for the raw, sales and injection gas streams for individual representative high CO_2 content discoveries

Economy	Basin	Formation	Location	Raw gas flow-rate (Mt/yr)				Sales gas flow-rate (Mt/yr)				Injection gas flow-rate (Mt/yr)			
				Methane	Other H/C	CO_2	Total	Methane	Other H/C	CO_2	Total	Methane	Other H/C	CO_2	Total
Indonesia	Bintuni B.	Lower Kembelangan Gp	Offshore	2.38	1.12	1.44	4.94	2.30	1.11	0.59	4.00	0.08	0.01	0.85	0.95
	E. Natuna B.	Terumbu Fm	Offshore	24	11	191	226	22	11	19	53	1.3	0.2	172	173
	N.W. Java B.	Batu Raja Fm	Onshore	0.08	0.04	0.41	0.53	0.08	0.04	0.07	0.18	0.004	0.001	0.34	0.35
		Talang Akar Fm	Onshore	0.02	0.01	0.33	0.36	0.02	0.01	0.03	0.06	0.001	negl.	0.30	0.30
	N. Sumatra B.	Oligocene Sst	Offshore	0.48	0.22	1.64	2.34	0.46	0.22	0.28	0.95	0.020	0.004	1.36	1.38
		Peutu Fm	Onshore	3.96	1.87	5.85	11.68	3.87	1.85	1.34	7.06	0.099	0.019	4.50	4.62
	C. Sumatra B.	Sihapas Gp Sst	Onshore	0.24	0.11	0.20	0.55	0.23	0.11	0.05	0.39	0.006	0.001	0.15	0.16
		Pematang Fm	Onshore	0.24	0.11	0.20	0.55	0.23	0.11	0.05	0.39	0.007	0.001	0.16	0.16
	S. Sumatra B.	Talang Akar Fm	Onshore	0.11	0.05	0.31	0.48	0.10	0.05	0.06	0.21	0.009	0.002	0.25	0.26
	Kutei B.	Miocene Delta Sst	Onshore	1.19	0.56	1.02	2.77	1.16	0.55	0.25	1.96	0.034	0.006	0.78	0.82
Malaysia / Vietnam	Malay B.	D Group	Offshore	0.63	0.30	0.94	1.87	0.62	0.30	0.22	1.13	0.016	0.003	0.72	0.74
		E Group	Offshore	1.19	0.56	2.20	3.95	1.10	0.54	0.46	2.11	0.088	0.017	1.74	1.85
		H Group	Offshore	0.24	0.11	1.23	1.58	0.23	0.11	0.20	0.53	0.011	0.002	1.03	1.04
		K Group	Offshore	0.24	0.11	1.23	1.58	0.23	0.11	0.20	0.54	0.005	0.001	1.03	1.04
		I Group	Offshore	0.24	0.11	1.23	1.58	0.23	0.11	0.20	0.53	0.011	0.002	1.03	1.04
		J Group	Offshore	0.24	0.11	1.23	1.58	0.23	0.11	0.20	0.53	0.011	0.002	1.03	1.04
		L Group	Offshore	0.24	0.11	1.23	1.58	0.23	0.11	0.20	0.54	0.005	0.001	1.03	1.04
	Nam Con Son B.	Nam Con Son Fm	Offshore	1.19	0.56	0.31	2.06	1.09	0.54	0.20	1.84	0.095	0.018	0.11	0.22
Thailand	G. of Thailand B.	Pattani Trough	Offshore	1.51	0.71	1.73	3.94	1.42	0.69	0.40	2.52	0.083	0.016	1.33	1.43
Brunei	Baram Delta B.	Cycle V	Offshore	1.98	0.94	27.28	30.20	1.89	0.92	2.18	4.99	0.090	0.017	25.10	25.21

Table 7 – Volumetric composition-rates for the raw, sales and injection gas streams for individual representative high CO_2 content discoveries

Economy	Basin	Formation	Location	Raw gas flow-rate (vol%)				Sales gas flow-rate (vol%)				Injection gas flow-rate (vol%)			
				Methane	Other H/C	CO_2	Total	Methane	Other H/C	CO_2	Total	Methane	Other H/C	CO_2	Total
Indonesia	Bintuni B.	Lower Kembelangan Gp	Offshore	68%	17%	15%	100%	74%	19%	7%	100%	20%	2%	78%	100%
Indonesia	E. Natuna B.	Terumbu Fm	Offshore	24%	6%	70%	100%	64%	17%	20%	100%	2%	0.2%	98%	100%
Indonesia	N.W. Java B.	Batu Raja Fm	Onshore	32%	8%	60%	100%	64%	16%	20%	100%	3%	0.3%	97%	100%
Indonesia	N.W. Java B.	Talang Akar Fm	Onshore	16%	4%	80%	100%	60%	15%	25%	100%	1%	0.1%	99%	100%
Indonesia	N. Sumatra B.	Oligocene Sst	Offshore	40%	10%	50%	100%	68%	17%	15%	100%	4%	0.4%	96%	100%
Indonesia	N. Sumatra B.	Peutu Fm	Onshore	56%	14%	30%	100%	72%	18%	9%	100%	6%	1%	94%	100%
Indonesia	C. Sumatra B.	Sihapas Gp Sst	Onshore	64%	16%	20%	100%	75%	19%	6%	100%	9%	1%	90%	100%
Indonesia	C. Sumatra B.	Pematang Fm	Onshore	64%	16%	20%	100%	75%	19%	6%	100%	10%	1%	88%	100%
Indonesia	S. Sumatra B.	Talang Akar Fm	Onshore	44%	11%	45%	100%	68%	18%	14%	100%	9%	1%	90%	100%
Indonesia	Kutei B.	Miocene Delta Sst	Onshore	64%	16%	20%	100%	75%	19%	6%	100%	10%	1%	88%	100%
Malaysia	Malay B.	D Group	Offshore	56%	14%	30%	100%	72%	18%	9%	100%	6%	1%	94%	100%
Malaysia	Malay B.	E Group	Offshore	52%	13%	35%	100%	71%	19%	11%	100%	12%	1%	87%	100%
Malaysia / Vietnam	Malay B.	H Group	Offshore	32%	8%	60%	100%	64%	16%	20%	100%	3%	0.3%	97%	100%
Malaysia / Vietnam	Malay B.	K Group	Offshore	32%	8%	60%	100%	64%	16%	20%	100%	1%	0.1%	98%	100%
Vietnam	Malay B.	I Group	Offshore	32%	8%	60%	100%	64%	16%	20%	100%	3%	0.3%	97%	100%
Vietnam	Malay B.	J Group	Offshore	32%	8%	60%	100%	64%	16%	20%	100%	3%	0.3%	97%	100%
Vietnam	Malay B.	L Group	Offshore	32%	8%	60%	100%	64%	16%	20%	100%	1%	0.1%	98%	100%
Vietnam	Nam Con Son B.	Nam Con Son Fm	Offshore	74%	19%	7%	100%	75%	20%	5%	100%	66%	7%	27%	100%
Thailand	G. of Thailand B.	Pattani Trough	Offshore	60%	15%	25%	100%	74%	19%	7%	100%	14%	1%	84%	100%
Brunei	Baram Delta B.	Cycle V	Offshore	16%	4%	80%	100%	60%	15%	25%	100%	1%	0.1%	99%	100%

15. We estimate the required number of injection wells using simple reservoir simulations. Injection takes place in the centre of the formation and occupies 25% of the total formation area. We make this assumption because formation heterogeneity and structure, faulting, sweet spots for injection and so on mean that the whole formation will not practically be available for injection.

Increasing the injection area is expected to increase injectivity for a given total injection rate. However, increasing the injection area within the formation lowers the aquifer strength and so the overall injectivity is not expected to increase significantly. That part of the location surrounding the injection area is an aquifer. The simulation grid size varies depending on the area of the location.

For a given number of injection wells, by repeated simulations we establish iteratively the maximum rate of CO_2 that can be injected over the injection period without the pressure in the reservoir exceeding its fracture pressure. This maximum rate is then established for different numbers of wells. The maximum depends on the properties of the reservoir including its permeability, reservoir thickness and fracture pressure. An example of the results of the simulations is shown in Figure 7.

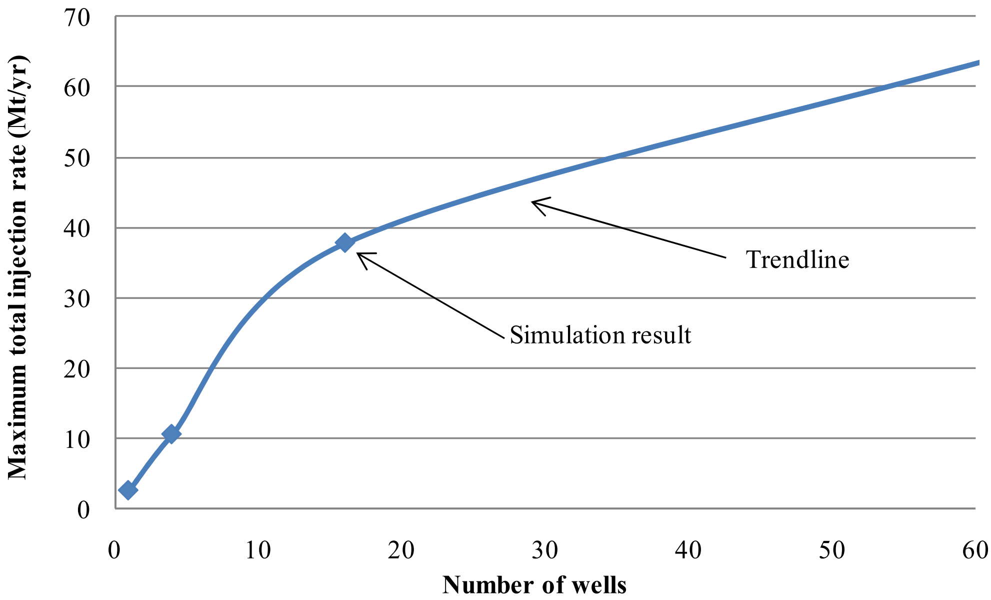


Figure 7 – Example results of reservoir simulation

16. We assume that each project lasts for 20 years. To get the annual raw gas production rate we divide the total resource content of the formation by the project life.

17. The number of injection wells estimated by simulations is likely to provide a lower limit to the wells required because the simulations omit other factors that influence injection (such as tubing effects and reservoir heterogeneity). We therefore apply an empirically-based contingency factor to take these other factors into account.

18. We do not consider the design or costs of monitoring CO_2 storage before during of after the injection period. The design will be very case-specific and we do not have sufficient data to enable a proper analysis of the monitoring system.

19. The capital costs include the costs of extra power, compression, pipelines and injection both platforms and wells. In addition, we calculate the auxiliary costs of constructing the transport and injection project. We refer to these costs as 'On-Costs'. They include insurance, obtaining rights-of-way, legal and regulatory costs, contingency and so on.

20. We report the capital, operating and decommissioning costs for each case examined as well as the present value of these costs. We also present the specific cost of CO_2-e avoided. The specific cost of CO_2-e avoided is calculated by dividing the present value of all costs by the present value of CO_2-e avoided.

4.2 Economic assumptions

We estimate transport and injection costs in real US$2010 terms. Our calculations of the cost per tonne avoided incorporate a real discount rate of 7%.

The calculations also assume a construction period of 3 years and an injection period of either 20 years for the representative analyses and varying periods for the individual case studies. We assume that the project is decommissioned after the injection period.

Where possible, we have employed recommended IEA assumptions. Our methodology for calculating the costs of transport and storage per tonne of CO_2-e avoided is given in Allinson *et al.* [37].

4.3 Source assumptions

For each selected storage formation, we assume a representative gas discovery with high CO_2 content as the CO_2 emission source. We assume that the representative discovery is located in the same formation and the produced CO_2 is injected into a saline formation below the gas reservoir.

Table 3 summarises the key parameters of representative gas discoveries in the formations. We assume resources and a CO_2 content of each representative gas discovery based on data for actual gas discoveries in each formation.

Since both resources and the CO_2 content of each representative gas discovery are subject to large uncertainties, we carry out sensitivity analyses to evaluate the impact of changes in CO_2 flow-rate on the economics. Table 4 gives the CO_2 flow-rates we assume for the sensitivity analyses.

Figure 8 – Sedimentary basins in South-East Asia [60]

Source: Newlands, I. and R. Langford, 2005. *CO_2 Storage Prospectivity of Selected Sedimentary Basins in the Region of China and South-East Asia*, Geoscience Australia, APEC Energy Working Group project EWG 06/2003.

4.4 Injection site assumptions

An APEC study by Newlands and Langford, "CO_2 Storage Prospectivity of Selected Sedimentary Basins in the Region of China and South-East Asia" [60], identified potential CO_2 storage basins/formations in selected member economies of the APEC region. This section refers to the APEC study as well as other literature and bases its analyses on eleven basins (twenty formations) as potential CO_2 storage sinks.

The quantitative representative analyses presented elsewhere in this report rely solely on indicative data on the reservoir properties of sedimentary basins in South-East Asia. These are based on geological assessments, seismic surveys and well drilling for oil and gas exploration and production. This generalised basin data is not sufficiently detailed to allow us to distinguish between specific types of storage reservoir into which CO_2 might be injected. We assume in this report that all storage reservoirs are saline formations.

All the quantitative representative analyses in this report assume CO_2 injection into a subsurface reservoir with a given set of reservoir properties. They assume supercritical or subcritical CO_2 injection depending on the pressure regime of the transport and injection operation. The analyses implicitly assume injection sites with the reservoir properties assumed for the sedimentary basin where they are located.

Individual depleted or producing oil and gas fields are unlikely to have the same pressure regime as we assume applies to the sedimentary basin and we do not attempt to analyse depleted or producing fields in our representative cases.

Table 3 shows the potential CO_2 storage sinks selected for analysis.

The reservoir properties of the storage formations are given in Appendix 3. In some cases there is very little data on the potential storage sites. Therefore we make simplifying assumptions and estimates for the illustrative analyses.

4.5 Injection scheme

We assume that the CO_2 has already been separated from the raw gas stream on the production platform before the methane is exported. The separation process in most cases[4] produces a stream of more than 75% CO_2 (see Table 7 for actual concentrations). For offshore discoveries, the injection gas is compressed on a dedicated un-manned platform and then transported to the storage site for injection into the subsurface. We assume un-manned injection platforms to host the injection wells. The injection site is 10 km from the gas discovery. A schematic diagram of the process is shown in Figure 9. For onshore discoveries we assume that the storage site is also onshore, sited 10 km from production facility.

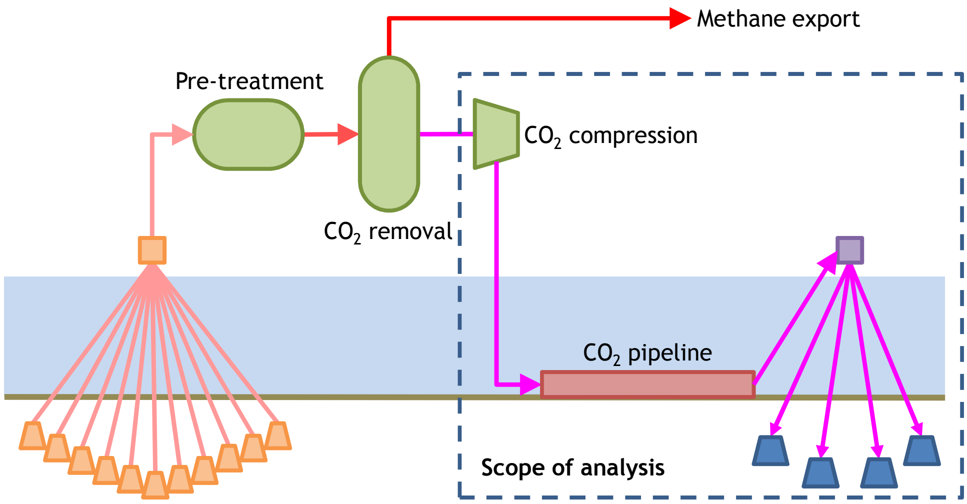


Figure 9 – Process schematic of a representative development with CCS

[4] The injection gas from Nam Con Son Formation is different. It has 27% CO_2.

4.6 Cost estimates

In this section we present the results of our analyses of the costs of transport and injection for both the base cases and sensitivity cases. We also present the average costs of transport and injection for each economy under consideration.

4.6.1 Costs for each base case

Figure 10 and Table 8 show that our estimates of the costs of CO_2 compression, transport and injection for individual basins range from US$3 to US$67 per tonne avoided in A$2010 terms depending on the project. The most expensive discovery is Pematang Fm (Central Sumatra Basin, Indonesia), whereas the cheapest discovery is the Terumbu Fm (East Natuna Basin, Indonesia). Approximately a quarter of the total costs are for compression (both machinery and platforms) with a further quarter-to-half of the total costs for injection (both wells and platforms). In some cases, two-thirds of the compression costs are for the compressor platforms. More details are provided in Appendix 4.

The range of estimates reflects the different volumes of CO_2 injected, different locations (onshore, shallow water, deep water) and formation characteristics. None of our estimates include the cost of CO_2 capture. We report costs in terms of CO_2-e avoided and not CO_2 avoided. The amount of CO_2-e injected is generally between one and three times the amount of CO_2 injected. In the case of Nam Con Son Basin, the CO_2-e injected is almost twelve times the CO_2 injected because of the low concentration of CO_2 in the injection gas.

The lowest absolute costs are for the Talang Akar Fm (North West Java Basin, Indonesia) with an up-front capital cost of US$66 million and a present value of all costs of US$72 million. While, the highest absolute costs are for the Terumbu Fm (East Natuna Basin, Indonesia) with up-front capital costs and present values of all costs of US$4,880 million and US$6,460 million respectively.

The specific cost of the Terumbu Fm (East Natuna Basin, Indonesia) is low because the process has large flow-rates (over 170 Mt/yr) with favourable injection characteristics and so high injectivities. There are therefore economies of scale in transport as well as large quantities of CO_2-e avoided. The latter means that the significant capital, operating and decommissioning costs are translated into a very small specific cost of CO_2-e avoided. This discovery also has the largest absolute costs of any of the representative discoveries.

The most expensive discovery on a specific cost basis is the Pematang Fm (Central Sumatra Basin, Indonesia). This case has very low flow-rates (less than 1 Mt/yr) and also very low injectivity.

We also calculate the average cost of all the discoveries by dividing the total present value of all costs for all formations by the total present value of CO_2-e avoided for all formations. This gives an average cost of approximately US$5 per tonne of CO_2-e avoided. This cost is lower than all but two of the formations. The reason for this is that the two cheapest formations comprise 80% of the total CO_2-e avoided by all the projects.

The effect of flow-rate on cost is shown in Figure 11 where the specific cost is plotted as a function of the annual rate of CO_2-e avoided using a logarithmic scale. The graph shows that cost decreases significantly as the rate of CO_2-e avoided increases. In fact the cost increases sharply at flow-rates below 1 Mt/yr.

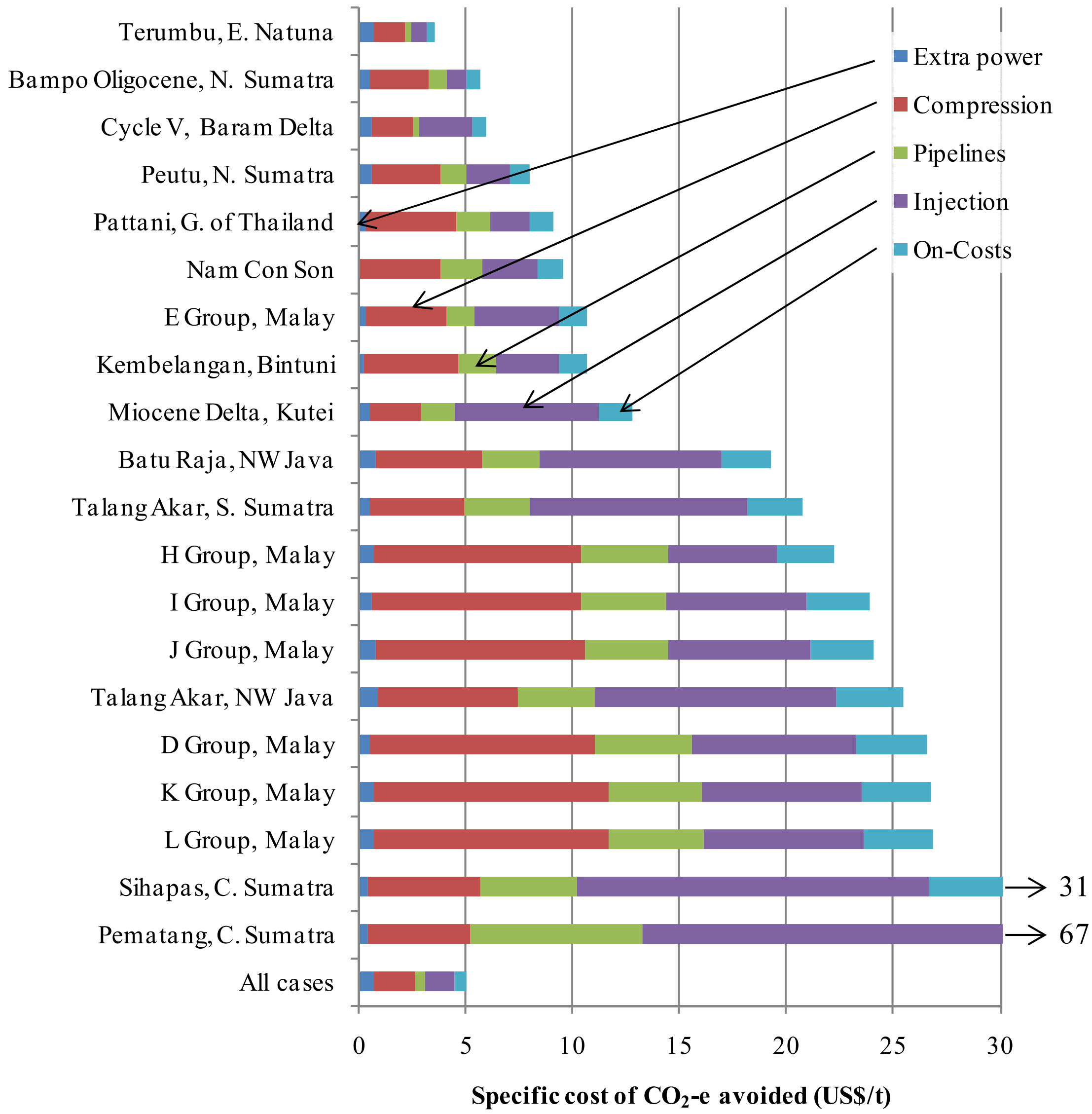


Figure 10 – Ranking of representative base cases on the basis of specific cost of CO_2-e avoided

4.6.2 Costs for each economy

The cases discussed in the previous section are representative of a typical or average field in each of the formations investigated. We extend this analysis by summing the present values of all costs and of CO_2-e avoided for all the formations in each economy and calculating a typical specific cost of CO_2-e avoided. These values are not a weighted average cost for each economy. This would require weighting each formation cost and CO_2-e avoided by the proportion of an economy's total resource contained in that formation. We calculate the simple average to allow comparison of costs between economies.

Table 8 – Results for base cases

Economy	Basin	Formation	Location	Rate of CO_2-e injected (Mt/yr)	Rate of CO_2-e avoided (Mt/yr)	PV of CO_2-e avoided (Mt)	Capital costs (US$ million)	Annual operating costs (US$ million/yr)	Decomm-issioning costs (US$ million)	PV of costs (US$ million)	Specific cost of CO_2-e avoided (US$/t)
Indonesia	Bintuni Basin	Lower Kembelangan Gp	Offshore	2.9	2.9	25.0	244	5.9	60	268	10.7
Indonesia	E. Natuna	Terumbu Fm	Offshore	206	204	1,763	4,880	246	1,152	6,459	3.7
Indonesia	N.W. Java Basin	Batu Raja Fm	Onshore	0.4	0.4	3.8	67	1.6	16	73	19.3
Indonesia	N.W. Java Basin	Talang Akar Fm	Onshore	0.3	0.3	2.8	66	1.5	16	72	25.5
Indonesia	N. Sumatra Basin	Oligocene Sst	Offshore	7.1	7.0	60.9	295	9.8	72	347	5.7
Indonesia	N. Sumatra Basin	Peutu Fm	Onshore	1.9	1.9	16.1	112	3.3	27	128	8.0
Indonesia	C. Sumatra Basin	Sihapas Gp Sst	Onshore	0.3	0.3	2.6	75	1.4	19	79	30.5
Indonesia	C. Sumatra Basin	Pematang Fm	Onshore	0.3	0.3	2.8	183	3.2	46	190	66.6
Indonesia	S. Sumatra Basin	Talang Akar Fm	Onshore	0.5	0.5	4.2	81	1.7	20	86	20.8
Indonesia	Kutei Basin	Miocene Delta Sst	Onshore	1.7	1.6	14.2	169	3.7	42	182	12.8
Malaysia	Malay Basin	D Group	Offshore	1.1	1.1	9.7	236	5.6	59	258	26.5
Malaysia	Malay Basin	E Group	Offshore	4.0	4.0	34.7	336	8.3	83	370	10.7
Malaysia / Vietnam	Malay Basin	H Group	Offshore	1.3	1.3	11.3	226	5.8	56	250	22.2
Malaysia / Vietnam	Malay Basin	K Group	Offshore	1.2	1.2	10.1	244	6.1	60	269	26.7
Vietnam	Malay Basin	I Group	Offshore	1.3	1.3	11.3	244	6.1	60	269	23.9
Vietnam	Malay Basin	J Group	Offshore	1.3	1.3	11.3	245	6.2	60	271	24.0
Vietnam	Malay Basin	L Group	Offshore	1.2	1.2	10.1	245	6.1	61	270	26.9
Vietnam	Nam Con Son Basin	Nam Con Son Fm	Offshore	2.6	2.6	22.4	198	4.4	49	214	9.6
Thailand	G. of Thailand Basin	Pattani Trough	Offshore	3.5	3.5	30.1	245	6.5	61	274	9.1
Brunei	Baram Delta Basin	Cycle V	Offshore	27	27	236	1,195	40	289	1,405	6.0

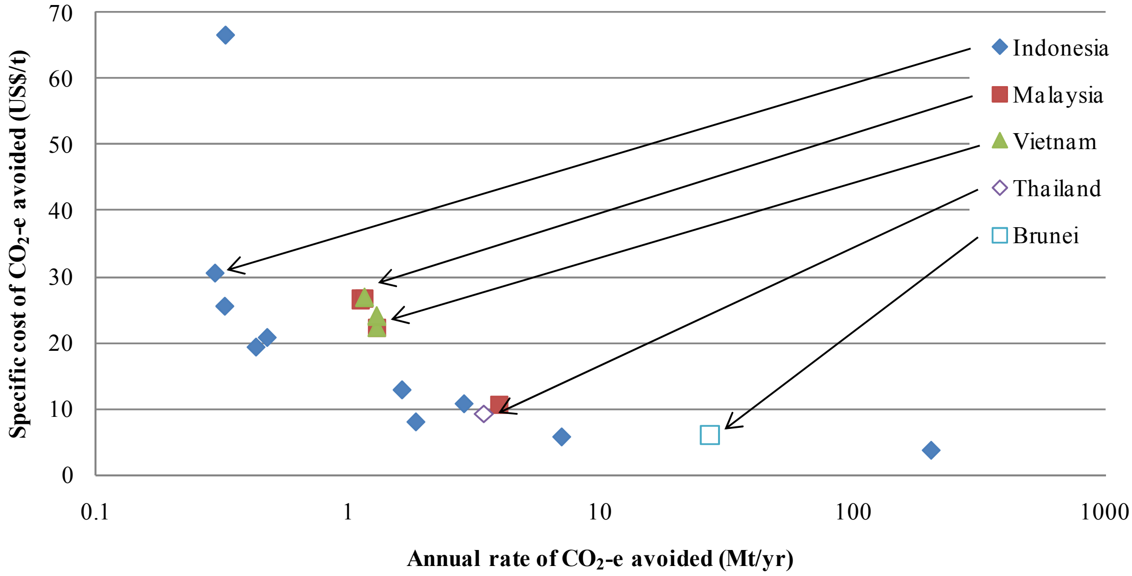


Figure 11 – Plot of representative costs as a function of annual injection rate of CO_2-e

The H and K Groups of the Malay Basin occur in both Malaysian and Vietnamese waters. Since the representative case studies simulate typical fields rather all fields in each formation, we include the H and K Group cases in both the average Malaysian and Vietnamese costs.

The results of our analysis are given in Figure 12 and Table 9. These results show that Indonesia is the cheapest (US$4 per tonne) as it benefits from including the two largest CO_2-e injection projects. The next cheapest is Brunei (US$6 per tonne) whose sole formation represents 10% of all the CO_2-e avoided in this analysis. The sole Thai formation has moderate flow-rates and moderate costs and so has a moderate specific cost (US$9 per tonne). The Malaysian and Vietnamese discoveries have low flow-rates of CO_2-e (mostly about 1 Mt/yr). They are also offshore. Therefore, they have relatively high specific costs (US$14 and US$18 per tonne respectively).

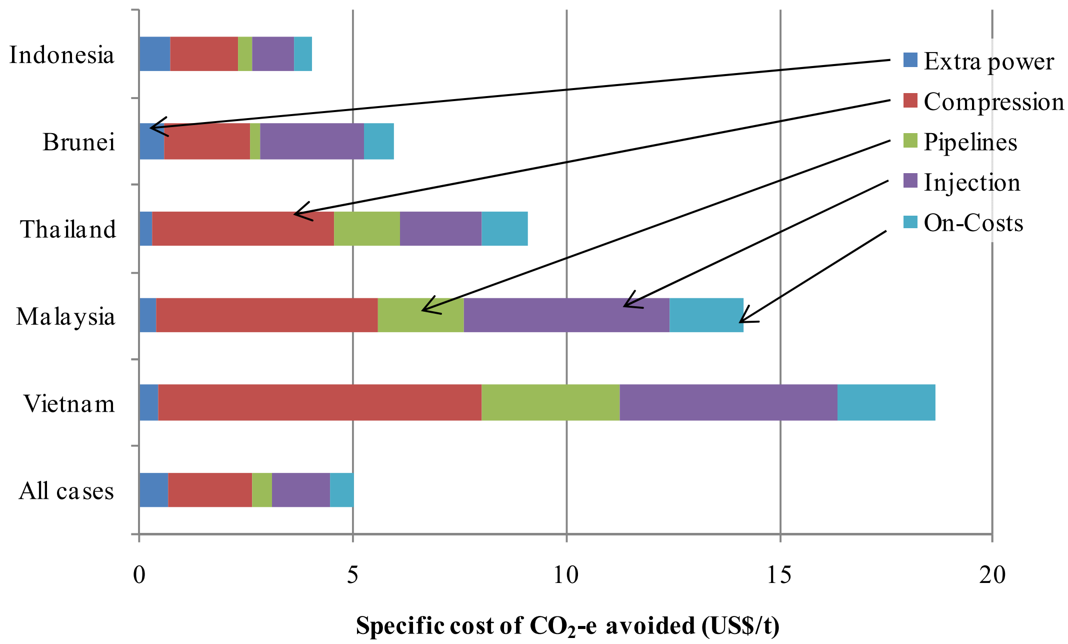


Figure 12 – Ranking of economies on the basis of specific cost of CO_2-e avoided

Table 9 – Results for each economy and for all cases

Economy	Rate of CO_2-e injected (Mt/yr)	Rate of CO_2-e avoided (Mt/yr)	PV of CO_2-e avoided (Mt)	Capital costs (US$ million)	Annual operating costs (US$ million/yr)	Decommissioning costs (US$ million)	PV of costs (US$ million)	Specific cost of CO_2-e avoided (US$/t)
Indonesia	221	219	1,895	6,171	278	1,470	7,883	4.2
Malaysia	5.2	5.1	44	572	14	141	628	14.1
Vietnam	6.4	6.4	55	932	23	231	1,024	18.6
Thailand	3.5	3.5	30	245	7	61	274	9.1
Brunei	27	27	236	1,195	40	289	1,405	6.0
All cases	266	264	2,282	9,585	373	2,308	11,735	5.1

4.6.3 Costs for individual economies

Figure 13 shows the costs of the Indonesian representative discoveries. The cost of all Indonesian cases is provided for comparison. The Terumbu formation is the cheapest and the Pematang the most expensive. Because of the effect of Terumbu, most Indonesian discoveries are more expensive than the economy average of US$4 per tonne of CO_2-e avoided.

The Malaysian cases are shown in Figure 14. Three of the four discoveries cost about US$25 per tonne with the E Group of the Malay Basin costing just over US$10 per tonne. The average cost across the four discoveries is US$14 per tonne of CO_2-e avoided.

Figure 15 shows the results for Vietnam. Again most of the representative discoveries cost around US$25 per tonne of CO_2-e avoided. The Nam Con Son Formation is the cheapest at just under US$10 per tonne. The average cost for a Vietnamese discovery is almost US$19 per tonne of CO_2-e avoided.

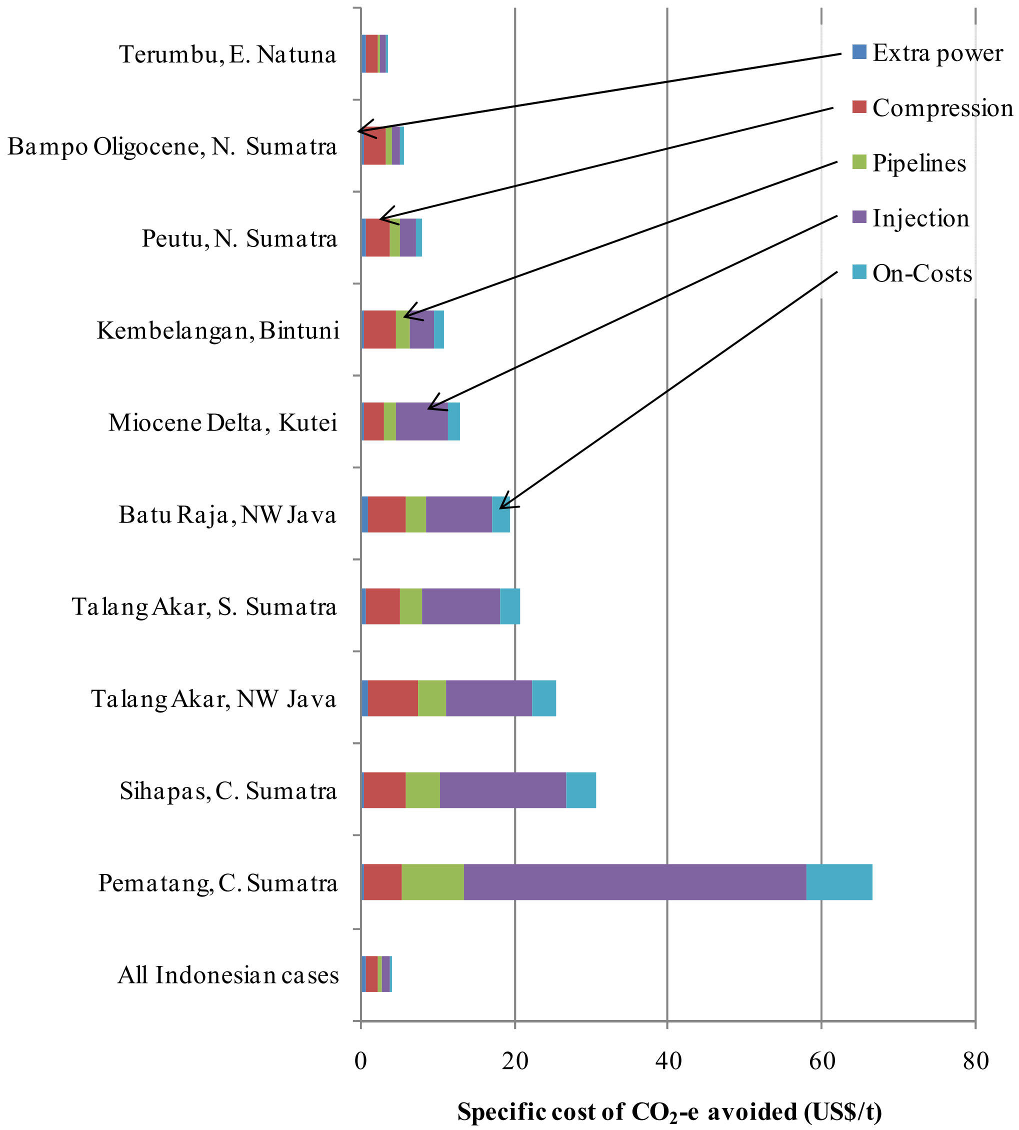


Figure 13 – Ranking of Indonesian cases and all Indonesia together

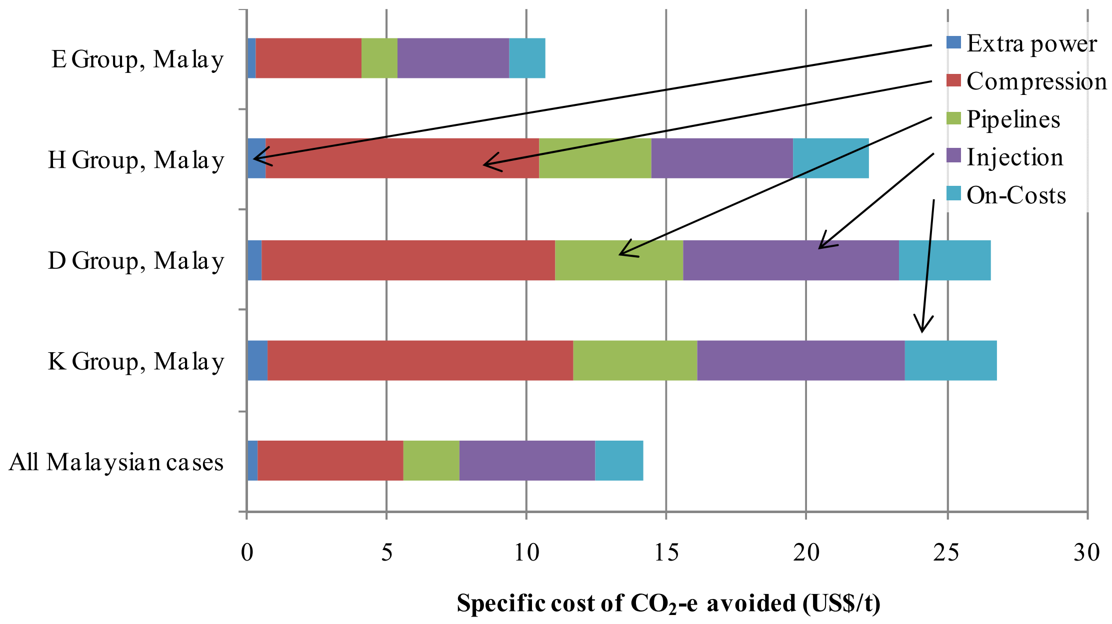


Figure 14 – Ranking of Malaysian cases and all Malaysia together

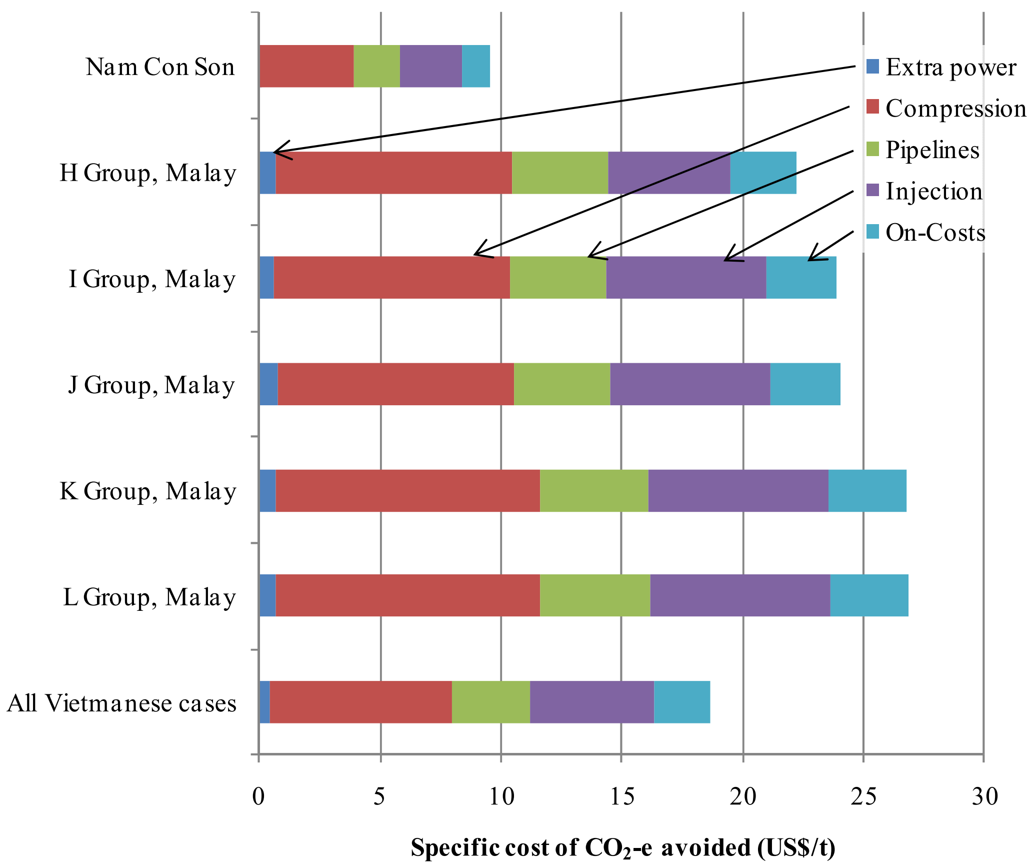


Figure 15 – Ranking of Vietnamese cases and all Vietnam together

4.6.4 Sensitivity of cost to injection flow-rate

For each of the base cases discussed above, we also analyse the sensitivity of the results to varying injection gas flow-rates. The specific cost of CO_2-e avoided for all the sensitivity cases are shown as a scatter plot in Figure 16. As in Figure 11, the results show that cost generally decreases as the rate of CO_2-e injected or avoided increases. The reduction in cost with increasing rates reflects mainly the economies of scale.

Figure 17 shows how the present values of all costs are relatively stable up to 10 Mt/yr, keeping below US$25 million. Beyond 10 Mt/yr, the costs increase rapidly. Figure 18 shows the spread of specific costs for each of the discoveries considered across the range of sensitivity flow-rates. The discoveries are ranked according to the base case cost.

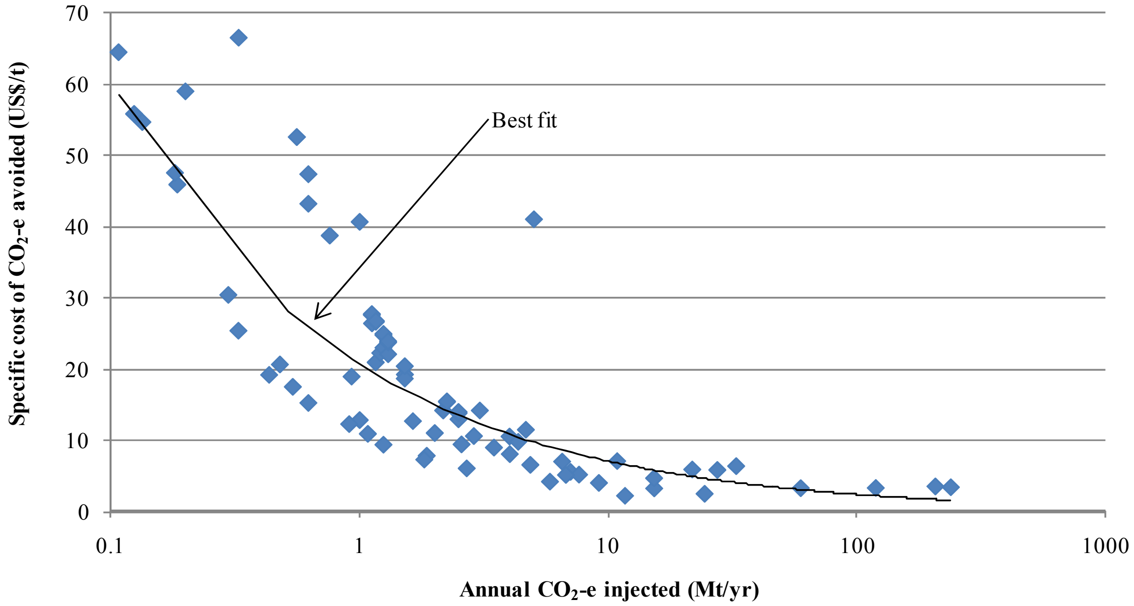


Figure 16 – Scatter of the specific cost of CO_2-e avoided for the sensitivity cases as a function of the annual rate of CO_2-e injected

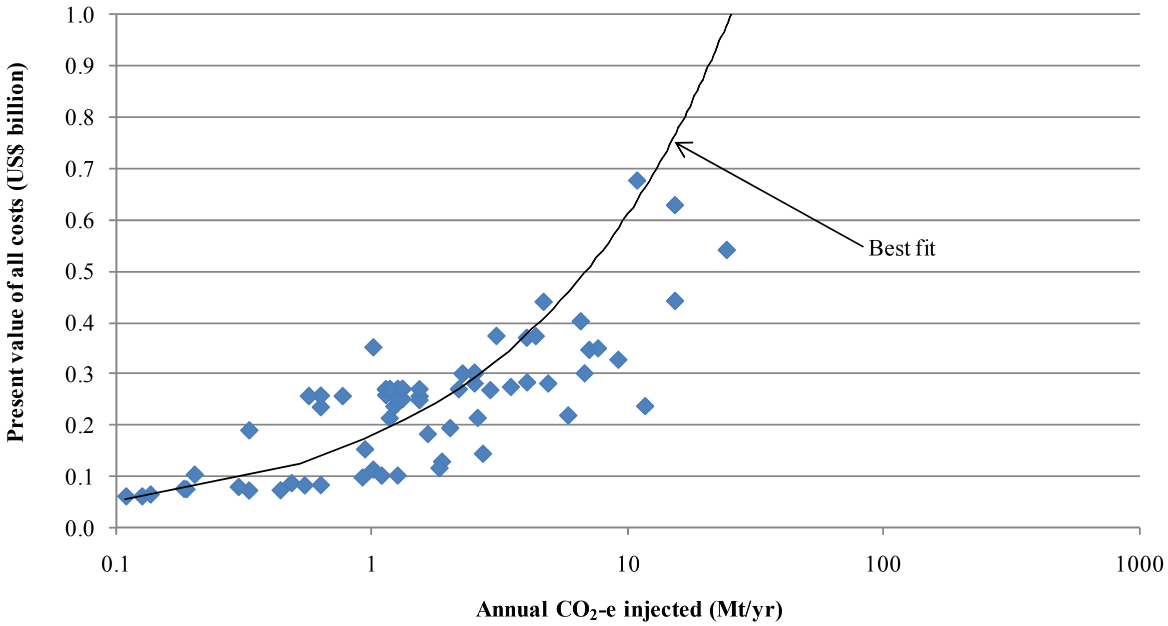


Figure 17 – Scatter of the present value of all costs for the sensitivity cases as a function of the annual rate of CO_2-e injected

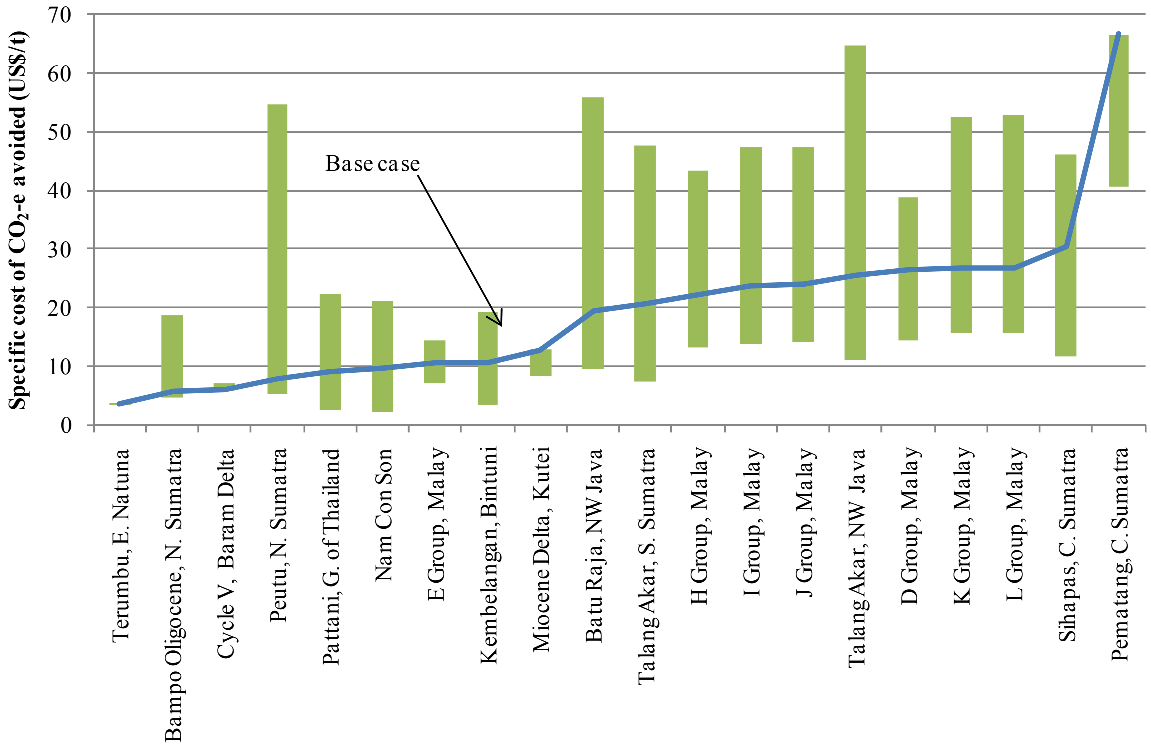


Figure 18 – Spread of sensitivity results for each representative case ranked by base case cost

5 Effect of fiscal terms

5.1 Fiscal terms

This section gives an analysis of the economic effects of the fiscal terms which are typical of current agreements in the five economies discussed in this report. Depending on how governments deal with the effects of CO_2 transport and storage on these terms, they can have a significant effect.

At the time of writing we cannot know how a carbon trading or a carbon tax regime would be treated in the fiscal terms applying to gas field developments in South-East Asia. For the analyses in this section, we make the simplifying assumption that a carbon price would provide additional revenues to a gas development over and above revenues from gas and liquids production.

The appendices contain a detailed description of the fiscal terms in each jurisdiction.

5.2 Analysis before Government take

The sensitivity analyses of the costs of representative CO_2 transport and injection projects discussed above exclude the effect of the fiscal terms (Government take). They show that the costs range from US$3 to US$67 per tonne avoided.

This implies that, ignoring the effects of the fiscal terms, the potential price of carbon would need to be at least US$3 to US$67 per tonne of CO_2-e avoided before the CCS projects could be economically justified.

For CO_2 transport and injection projects, the volume of CO_2-e avoided is of a similar order of magnitude to the volume of CO_2-e injected. Therefore, we could say that to justify a CO_2 transport and storage project, the minimum price of carbon per tonne injected would need to be roughly the same as the costs per tonne avoided quoted above.

In practice, however, the costs of CO_2 transport and storage or the potential revenues from CO_2 price might be subject to the same fiscal terms as applies to the natural gas projects that give rise to the emissions. If so, the financial effects would be significantly different. This aspect is discussed in the following section.

5.3 Costs after Government take

In the five economies in South-East Asia discussed in this report, natural gas projects have relatively high fiscal take in the form of royalties, taxes, Government profit sharing and so on. The total revenue the government receives as a percentage of the total net present value (NPV) of a gas discovery development ranges from about 55% to up to almost 100% depending on the fiscal regime and the profitability of projects. Therefore, in the absence of revenues from a carbon trading regime and depending on the treatment of CCS projects, companies implementing CCS for an existing natural gas project in these economies can potentially gain considerable financial advantages in the form of fiscal relief.

For each economy/fiscal regime we carry out fiscal analyses to estimate the economic effect of implementing CO_2 transport and storage to an existing natural gas project with a high CO_2 content. The purpose of these analyses is to determine the fiscal relief a project can obtain by applying transport and storage in the absence of a carbon trading regime.

We define fiscal relief to be the reduction in Government take caused by increases in costs for a project that is or will be paying significant fiscal imposts to Governments. We assume that no additional revenue is obtained from a carbon price or from enhanced recovery.

In order to illustrate the principle involved, Table 10 below gives a simple hypothetical illustration of the effect of fiscal relief in one year under a simple hypothetical income tax regime with a tax rate of 40%.

Table 10 – Illustration of the effect of tax relief

Item (US$ million)	Existing project	Existing project with extra costs	Incremental effect of extra costs
Revenue	100	100	0
Deductions (costs)	10	20	10
Tax	40% * (100 – 10) = 36	40% * (100 - 20) = 32	-40%*(10) = -4 (tax relief)
Net cash flow after tax	= 100-10-36 = 54	= 100-20-32 = 48	= -6

In this example, the extra costs before tax are US$10 million. This reduces taxable income by US$10 million and the project pays US$4 million less tax than before (40% of US$10 million). Therefore the tax relief is US$4 million and the effective after-tax cost is US$6 million.

For the purpose of the analyses of fiscal relief on CO_2 transport and storage for the representative sensitivity analyses, we assume a range of hypothetical but representative existing natural gas developments with reserves varying from 100 Bcf to 5,000 Bcf. We assume that natural gas price varies from US$4/GJ to US$10/GJ to reflect the uncertainty in long term natural gas prices in domestic and international gas markets.

Table 11 below shows our estimates of the overall fiscal relief under the fiscal regime in each of the five economies we considered.

Table 11 – Fiscal relief in five economies/fiscal regimes

Economy	Fiscal relief
Malaysia	63% – 88%
Indonesia	58% – 76%
Vietnam	41% – 67%
Thailand	38% – 70%
Brunei	49% – 66%

Taking Malaysia as an example, if we apply CO_2 transport and storage to an existing natural gas development in Malaysia, under the Malaysian PSC the project will have a fiscal relief of 63% to 88% depending on its profitability. Assuming that the before-tax cost of CO_2 transport and storage is US$500 million, the after-tax cost would only be US$500 million × (1 - 63% to 88%) = US$185 million to US$110 million.

The effect of fiscal relief on the representative sensitivity analyses would be to reduce the costs to the levels given in Table 12.

Table 12 – The cost of CO_2 transport and injection before and after fiscal relief for the representative cases

Economy	Basin	Formation	Location	PV of CO_2-e avoided (Mt)	Before-tax PV of all costs (US$ million)	Before-tax cost of CO_2-e avoided (US$/t)	Fiscal relief	After-tax PV of all costs (US$ million)	After-tax cost of CO_2-e avoided (US$/t)
Indonesia	Bintuni	Kembelangan	Offshore	25.0	268	10.7	58% – 76%	65 – 113	2.6 – 4.6
	East Natuna	Terumbu	Offshore	1,762.6	6,459	3.7	58% – 76%	1,551 – 2,713	0.9 – 1.6
	N.W. Java	Batu Raja	Onshore	3.8	73	19.3	58% – 76%	18 – 31	4.7 – 8.2
	N.W. Java	Talang Akar	Onshore	2.8	72	25.5	58% – 76%	18 – 31	6.2 – 10.8
	North Sumatra	Bampo Oligocene	Offshore	60.9	347	5.7	58% – 76%	84 – 146	1.4 – 2.4
	North Sumatra	Peutu	Onshore	16.1	128	8.0	58% – 76%	31 – 54	2.0 – 3.4
	Central Sumatra	Sihapas	Onshore	2.6	79	30.5	58% – 76%	19 – 34	7.4 – 12.9
	Central Sumatra	Pematang	Onshore	2.8	190	66.6	58% – 76%	46 – 80	16.0 – 28.0
	South Sumatra	Talang Akar	Onshore	4.2	86	20.8	58% – 76%	21 – 37	5.0 – 8.8
	Kutei	Miocene Delta	Onshore	14.2	182	12.8	58% – 76%	44 – 77	3.1 – 5.4
Malaysia	Malay	D Group	Offshore	9.7	258	26.5	63% – 88%	31 – 96	3.2 – 9.9
Malaysia	Malay	E Group	Offshore	34.7	370	10.7	63% – 88%	45 – 137	1.3 – 4.0
Malaysia / Vietnam	Malay	H Group	Offshore	11.3	250	22.2	63% – 88%	31 – 93	2.7 – 8.3
Malaysia / Vietnam	Malay	K Group	Offshore	10.1	269	26.7	63% – 88%	33 – 100	3.3 – 9.9
Vietnam	Malay	I Group	Offshore	11.3	269	23.9	63% – 88%	33 – 100	2.9 – 8.9
Vietnam	Malay	J Group	Offshore	11.3	271	24.0	63% – 88%	33 – 101	2.9 – 8.9
Vietnam	Malay	L Group	Offshore	10.1	270	26.9	63% – 88%	33 – 101	3.3 – 10.0
Vietnam	Nam Con Son	Nam Con Son	Offshore	22.4	214	9.6	41% – 67%	71 – 127	3.2 – 5.7
Thailand	Gulf of Thailand	Pattani	Offshore	30.1	274	9.1	38% – 70%	83 – 170	2.8 – 5.7
Brunei	Baram Delta	Cycle V	Offshore	235.7	1,405	6.0	49% – 66%	478 – 717	2.1 – 3.1
Average						19.5			3.9 – 8.0

5.4 Required carbon prices after Government take

Section 5.2 above referred to the fact that revenues from a carbon trading regime would have to be at least roughly equal to the costs per tonne avoided to ensure that a CO_2 transport and injection project is economically viable. The analysis in Section 5.3 showed the effect of fiscal relief on the costs of CO_2 transport and storage assuming that the costs of CO_2 transport and injection could be deducted in full against the revenues from sales of natural gas. In this section, as in Section 5.2, we estimate minimum required carbon prices. However, in this section we now include the effects of the fiscal terms.

We continue to make the simplifying assumption that a carbon trading regime provides revenues and that these would be treated in the same way as gas and liquids revenues. That is, they would be subject to royalties, taxes, profit sharing and so on. From the point of view of establishing a minimum carbon price taking the fiscal terms into account, this is a conservative assumption. In practice, it might be that a carbon trading regime has a different treatment in the fiscal terms. For instance, it might be that such regimes affect some components of the fiscal terms and not others. If so, the required minimum carbon prices taking the fiscal terms into account would be lower than we calculate in this section.

If we include both (a) the potential revenues from a carbon price together with (b) the costs of CO_2 transport and storage, then the minimum required price to justify a commercial project can be significantly different from those stated in Section 5.2.

Table 13 shows a simplified single-year hypothetical analysis[5] of the combined incremental effect of (a) potential revenue from a carbon trading regime and (b) the costs of a CO_2 transport and injection project for a simple fiscal regime with terms similar to the Thailand I fiscal terms. The regime consists of a 12.5% royalty on gross revenue and income tax at 50% of taxable income. The table shows the minimum price of CO_2 required to justify implementing a CO_2 transport and injection project. We assume that the fiscal terms for oil and gas also apply to the revenues from a carbon price and the costs of transport and injection.

Table 13 shows that the costs of CO_2 transport and injection assumed are US$60 million. Therefore, ignoring fiscal effects, the revenue required to justify transport and injection would be US$60 million. Assuming that 3 Mt are injected, the minimum price of CO_2 required to make transport and injection economically viable after royalty and tax is US$22.86 per tonne injected.

However, if the effects of the fiscal terms are ignored, the price required is only US$20 per tonne injected (US$60 million divided by 3 Mt). This is approximately 10% less than the minimum price calculated after Government take.

In this example, the reason that the price of CO_2 must be higher after the illustrative fiscal terms are taken into account is that royalties are applied only to gross revenue and are independent of costs. In general, any component of the fiscal terms that does not take into account both revenues and costs as they are received and spent will lead to a required carbon price that is different to the price calculated before Government take. This is a feature of all fiscal regimes in South-East Asia.

Table 13 – Illustration of the effect of fiscal terms on the required price of CO_2

Carbon price assumed	US$/tonne injected	22.86
CO_2 injected assumed	Mt	3.00
Gross Revenue from a CO_2 transport and injection	US$ million	68.57
Costs of CO_2 transport and injection assumed	US$ million	60.00
Before-tax net cash flow	US$ million	8.57
Royalty at 12.5% of gross revenue	US$ million	8.57

[5] This analysis shows the incremental effect of a CO_2 transport and injection project in one year only. In practice, a complete analysis for the whole of project life would be required.

Gross Revenue	US$ million	68.57
Royalty	US$ million	8.57
Costs of CO_2 transport and injection	US$ million	60.00
Taxable income	US$ million	0.0
Income tax at 50% of taxable income	US$ million	0.0

Gross Revenue	US$ million	68.57
Royalty	US$ million	8.57
Costs of CO_2 transport and injection	US$ million	60.00
Tax	US$ million	0.0
After-tax net cash flow	US$ million	0.0

We have carried out analyses of the required minimum carbon price taking into account effect of the fiscal terms for the APEC economies examined in this report. The results are provided in Table 14. The table also shows the required minima ignoring the fiscal terms. It indicates that the required minimum prices after taking the effects of Government take into account are significantly higher than the corresponding minima obtained by excluding Government take. The average minimum price after the effects of Government take is approximately US$35 per tonne injected compared to approximately US$20 per tonne injected ignoring the effects of Government take. In other words, the effect of Government take could be to increase the required price of CO_2 on average by 75%.

These analyses refer only to the required minimum prices of CO_2 in any future carbon trading regime. They ignore the effects of additional revenues (if any) from enhanced oil or natural gas recovery. The minimum prices are those prices that make zero the net present value of the incremental CO_2 transport and injection project.

In general, CO_2 transport and injection is not explicitly recognised in South-East Asian fiscal regimes and the analysis above is preliminary and indicative based on the general assumptions that (a) revenues from any CO_2 price and (b) costs of CO_2 transport and injection will be subject to the same fiscal terms that apply to existing natural gas developments. This may or may not be the case.

In practice, across South-East Asia in the economies considered in this report, the fiscal treatment of CO_2 transport and injection projects is not yet clear. The analyses above are intended merely to illustrate that the way in which CO_2 transport and injection is treated in the fiscal terms can have a significant effect on the economics of such projects.

Table 14 – Required minimum prices of CO_2 before and after Government take

Economy	Basin	Formation	Location	PV of CO_2-e avoided[vi] (Mt)	Minimum price of CO_2 in US$/t[vii]	
					Before Government Take	After Government Take
Indonesia	Bintuni	Kembelangan	Offshore	25.0	10.7	15.5
Indonesia	East Natuna	Terumbu	Offshore	1,762.6	3.7	5.4
Indonesia	N.W. Java	Batu Raja	Onshore	3.8	19.3	28.0
Indonesia	N.W. Java	Talang Akar	Onshore	2.8	25.5	37.0
Indonesia	North Sumatra	Bampo Oligocene	Offshore	60.9	5.7	8.0
Indonesia	North Sumatra	Peutu	Onshore	16.1	8.0	11.3
Indonesia	Central Sumatra	Sihapas	Onshore	2.6	30.5	44.8
Indonesia	Central Sumatra	Pematang	Onshore	2.8	66.6	98.6
Indonesia	South Sumatra	Talang Akar	Onshore	4.2	20.8	30.3
Indonesia	Kutei	Miocene Delta	Onshore	14.2	12.8	18.7
Malaysia	Malay	D Group	Offshore	9.7	26.5	59.2
Malaysia	Malay	E Group	Offshore	34.7	10.7	23.7
Malaysia / Vietnam	Malay	H Group	Offshore	11.3	22.2	49.2
Malaysia / Vietnam	Malay	K Group	Offshore	10.1	26.7	59.5
Vietnam	Malay	I Group	Offshore	11.3	23.9	53.1
Vietnam	Malay	J Group	Offshore	11.3	24.0	53.3
Vietnam	Malay	L Group	Offshore	10.1	26.9	59.8
Vietnam	Nam Con Son	Nam Con Son	Offshore	22.4	9.6	16.5
Thailand	Gulf of Thailand	Pattani	Offshore	30.1	9.1	14.9
Brunei	Baram Delta	Cycle V	Offshore	235.7	6.0	8.7
Average					19.5	34.8

(vi) For CO_2 transport and injection projects, the volume of CO_2-e avoided is roughly the same as the volume of CO_2-e injected.

(vii) The table shows the approximate minimum prices per tonne of CO_2-e avoided required to ensure that the net present values of the CO_2 transport and injection projects at least zero.

6 Case studies

This section presents analyses of the techno-economics of potential CO_2 injection and storage projects using CO_2 from actual gas developments in South-East Asia. The analyses provide illustrations of the possibilities for CO_2 transport and storage in the region.

6.1 Tangga Barat

The fields comprising the Tangga Barat Cluster were discovered during 1980 and 1993 and are located about 150 km northeast of Kertih, Terengganu offshore Peninsular Malaysia in the PM 313 Block at water depths in the range 60 m to 71 m [77]. Figure 19 shows the location of the Tangga Barat Cluster fields.

The estimated proven plus probable recoverable natural gas resources are 1,070 billion cubic feet. The fields remain undeveloped. The content level of CO_2 is beyond the gas specification required for gas sales.

The current operator of the Tangga Barat Cluster is Petronas Carigali Sdn Bhd (PCSB) which holds a 100% working interest.

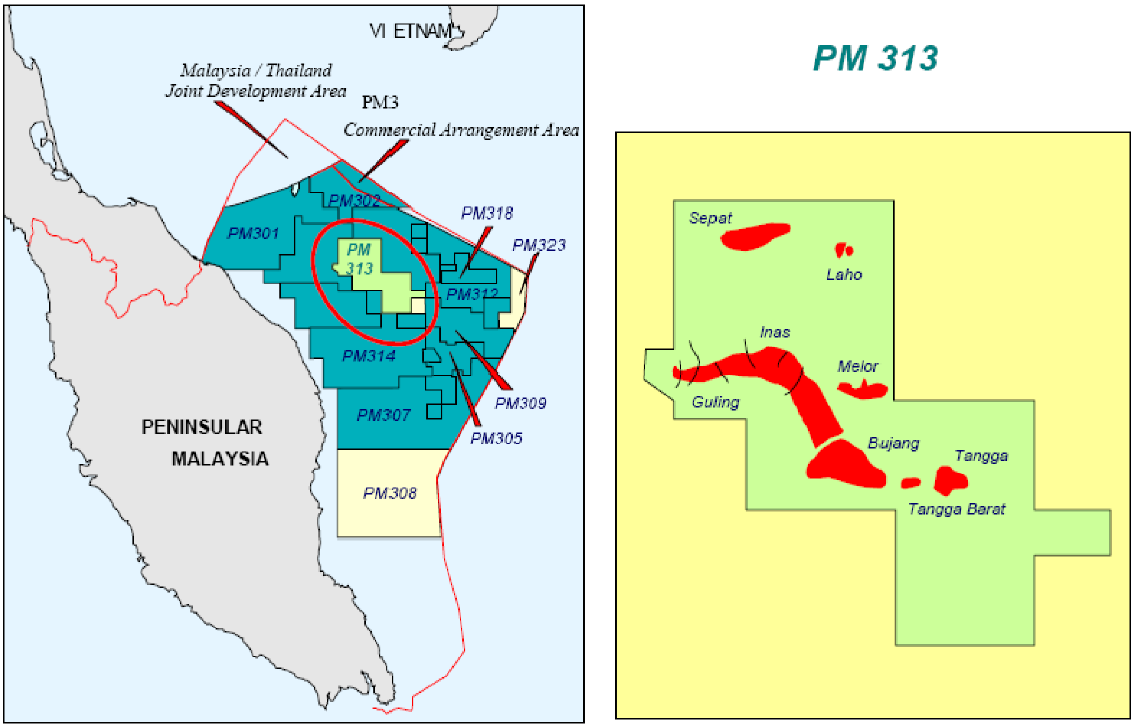


Figure 19 – The location of Tangga Barat Cluster gas fields [76]

Source: Darman, N. H. and A. R. B. Harun (2006). *Technical Challenges and Solutions on Natural Gas Development in Malaysia*. Beijing, China, Petronas / Petronas Carigali.

We assume that the development of the Tangga Barat Cluster comprises a total of 3 producing platforms and 1 central processing platform. We assume that the central processing platform accommodates all processing facilities, natural gas compression, main power generation, utilities and living quarters for field operations. The processing platform is 52 kilometres from the existing Resak production complex from which a 28 inch two-phase pipeline transports gas to the Resak Onshore Gas Terminal at Kertih. The Resak pipeline has sufficient spare capacity for the additional gas produced from Tangga Barat fields.

The development of the fields is designed for a capacity of 305 MMscf/d of raw gas with an initial blended CO_2 level of 34% prior to CO_2 removal. The raw gas will be processed, pre-treated and CO_2 content reduced to 10% to meet sales gas specification. For the purpose of this case study, we assume an annual average sales gas rate of 220 MMscf/d. This allows a 15-year production life of the fields. We assume that the CO_2 is separated from the raw gas with membranes.

After separation, approximately 10% of the sales gas is CO_2. The separated gas stream is 94% CO_2 and 6% methane and other hydrocarbons. This gas stream is transported and injected into a nearby saline formation.

Table 15 describes the composition of the raw, sales and injected gas assumed for the analysis in this report.

Table 15 – Composition of raw, sales and injected gas

Volumetric flow-rate (MMscf/d)	Raw gas	Sales gas	Injection gas
Methane	161	156	5
Other hydrocarbons	40	40	1
CO_2	104	23	81
Total	305	219	87
Mass flow-rate (Mt/yr)	**Raw gas**	**Sales gas**	**Injection gas**
Methane	1.1	1.1	0.0
Other hydrocarbons	0.5	0.5	0.01
CO_2	2.0	0.4	1.6
Total	3.7	2.1	1.6

6.1.1 Storage formation

CO_2 disposal studies carried out by Hong, T. Y., *et al.* [38] identified underground geological storage sites near the Tangga fields where the injected CO_2 volumes can be stored without increasing the reservoir pressure above the fracture pressure. The assumed storage site is located approximately 20 km from the Tangga Barat processing platform.

In this study, we assume that the separated gas stream is injected into a saline formation below the Tangga gas reservoirs (E Group) in the Malay Formation. E Group reservoirs were deposited in an estuarine depositional environment during the Early to Late Miocene. Reservior rocks have 25–30% porosity and up to 1,000 mD permeability [78]. Another source indicates that porosity ranges between 15% and 35% and permeabilities of main reservoirs ranges between 2 mD and 1,200 mD. Based on discussions with Petronas, we assume an porosity of 10% and a permeability of 290 mD for this analysis.

Based on data provided by Petronas, the reservoir pressure is 13.8 MPa (2,000 psi) and the fracture gradient is 14.7 MPa per kilometer (0.65 psi per feet).

Table 16 summarises the reservoir properties of E Group.

Table 16 – Storage formation properties

Variable	Units	Value	Notes
Economy		Malaysia	
Basin		Malay	
Formation/reservoir unit		E Group	
Areal extent of Basin	km^2	83,000	[60]
Depth base seal	m	1,300	Petronas
Formation thickness	m	300	Reservoir gross thickness (assumed)
Injection depth	m RKB	1,600	Calculated
Porosity	%	10	Petronas
Permeability	mD	250	Petronas
Formation temperature	°C	96	Petronas
Water depth	m SS	71	Assumed
Formation pressure at injection depth	MPa	13.79	Petronas
Fracture pressure at injection depth	MPa	23.53	Calculated based on fracture gradient
Fracture gradient	MPa/km	14.70	Petronas

These assumptions are subject to large uncertainties and variations in them can have a significant effect on the results of the economic analysis.

6.1.2 CO_2 handling

We estimate the equipment sizes, the capital, operating and decommissioning costs, as well as the costs per tonne of CO_2-e avoided for CO_2 transport and injection. The costs are presented in US$2010 terms. They are based on limited cost and reservoir data and have a large margin of error. We have modelled only transport and injection economics and have not modelled the economics of capture or the sources emitting the CO_2.

The main assumptions and methods used for the analyses are listed below.

1. We assume that 78% of the CO_2 produced with the methane is captured and injected into the subsurface. Therefore 22% of the CO_2 emissions are not captured but are exported along with the methane.
2. We assume that energy from a gas-fired generator is used to provide the additional energy for all transport and injection operations including compression and auxiliary equipment. The power plant does not have CO_2 capture facilities. A separate fixed platform is required for the power plant, compressor and auxiliary equipment.
3. We assume an injection period of 15 years to calculate the costs of transport and injection.
4. In this case, the injection gas is compressed from atmospheric conditions to a sufficiently high pressure (at least 8 MPa) to keep it in a supercritical state throughout the transport and injection stages. We estimate the compressor duty to be 4 MW.
5. The pipeline used to transport the injection gas is made from X70 carbon-steel line pipe with a maximum pipeline pressure of 18 MPa (2,610 psia). We assume a 20 km pipeline between the compression platform and the injection platform. We estimate that a 250 mm pipe will be required.
6. The separated gas stream is injected into the subsurface using 4 × 220 mm deviated wells from a steel jacket platform. We assume the same number of wells as planned by Petronas.

6.1.3 Cost estimates

We estimate the total extra capital cost for transport and injection to be US$220 million. The annual extra operating cost is US$8 million per year. At the end of the project the site is decommissioned at a real cost of US$50 million. In Table 17 we report unit capital costs for major equipment items. More detailed results are provided in Table 18.

Table 17 – Summary of estimated unit costs of CO_2 transport and storage for Tangga Barat

Items		Source	Results
Unit Capital Costs			
Power Plant	US$ million/MW	Estimated	0.8
Compressor	US$ million.yr/Mt	Estimated	19.2
Pipeline	US$ thousand/km.mm	Estimated	11
Wells	US$ million/well	Estimated	10
Injection platform (per platform)	US$ million/platform	Estimated	51
Injection platform (per slot)	US$ million/slot	Estimated	6.4
Total extra capital cost	US$ million	Estimated	220
Annual extra operating cost	US$ million/yr	Estimated	8
Extra decommissioning cost	US$ million	Estimated	50
Specific cost of CO_2-e avoided	US$/t CO_2-e avoided	Estimated	14.1

The specific cost of CO_2-e avoided quoted in Table 17 is the net present value of the real costs divided by the net present value of the CO_2-e avoided over a 15 year injection period.

Table 18 – Detailed estimated costs of CO_2 transport and storage for Tangga Barat

Items	Units	Source	Results
Total capital costs			
All power plants (1)	US$ million	Estimated	2
Source compressor machine (1)	US$ million	Estimated	30
Source compressor platform (1)	US$ million	Estimated	42
Well-head compressor machine (0)	US$ million	Estimated	–
Well-head compressor platform (0)	US$ million	Estimated	–
Transport pipeline	US$ million	Estimated	36
Inter-platform pipeline	US$ million	Estimated	–
Injection wells (4)	US$ million	Estimated	40
Injection platform (1)	US$ million	Estimated	35
On costs	US$ million	Estimated	35
Total cost	US$ million	Estimated	220
Annual operating costs			
All power plants (1)	US$ million/yr	Estimated	0.9
Source compressor machine (1)	US$ million/yr	Estimated	1.8
Source compressor platform (1)	US$ million/yr	Estimated	2.5
Well-head compressor machine (0)	US$ million/yr	Estimated	–
Well-head compressor platform (0)	US$ million/yr	Estimated	–
Transport pipeline	US$ million/yr	Estimated	0.5
Inter-platform pipeline	US$ million/yr	Estimated	–
Injection wells (4)	US$ million/yr	Estimated	1.6
Injection platform (1)	US$ million/yr	Estimated	1.0
On costs	US$ million/yr	Estimated	–
Total cost	US$ million/yr	Estimated	8.3
Total abandonment costs			
All power plants (1)	US$ million	Estimated	–
Source compressor machine (1)	US$ million	Estimated	7
Source compressor platform (1)	US$ million	Estimated	9
Well-head compressor machine (0)	US$ million	Estimated	–
Well-head compressor platform (0)	US$ million	Estimated	–
Transport pipeline	US$ million	Estimated	8
Inter-platform pipeline	US$ million	Estimated	–
Injection wells (4)	US$ million	Estimated	10
Injection platform (1)	US$ million	Estimated	8
On costs	US$ million	Estimated	8
Total cost	US$ million	Estimated	50
Specific cost of CO_2-e avoided			
All power plants (1)	US$/t CO2-e avoided	Estimated	0.5
Source compressor machine (1)	US$/t CO2-e avoided	Estimated	2.2
Source compressor platform (1)	US$/t CO2-e avoided	Estimated	3.0
Well-head compressor machine (0)	US$/t CO2-e avoided	Estimated	–
Well-head compressor platform (0)	US$/t CO2-e avoided	Estimated	–
Transport pipeline	US$/t CO2-e avoided	Estimated	2.0
Inter-platform pipeline	US$/t CO2-e avoided	Estimated	–
Injection wells (4)	US$/t CO2-e avoided	Estimated	2.6
Injection platform (1)	US$/t CO2-e avoided	Estimated	2
On costs	US$/t CO2-e avoided	Estimated	1.7
Total cost	US$/t CO2-e avoided	Estimated	14.1

6.1.4 Effects of fiscal terms

In Section 5 of this report, we discuss the effect of the fiscal terms on the economics of representative projects. Applying the same type of analysis to the Tangga Barat development gives the results shown in Table 19.

Table 19 – Effect of fiscal terms on CO_2 transport and storage for Tangga Barat

PV of CO_2-e avoided	Mt	18.4
Before-tax PV of all costs	US$ million	260.2
Before-tax cost of CO_2-e avoided	US$/t	14.1
Fiscal relief	%	63% – 88%
After-tax PV of all costs	US$ million	32 – 97
After-tax cost of CO_2-e avoided	US$/t	1.7 – 5.3
Minimum price of CO_2 before Government Take	US$/t	14.1
Minimum price of CO_2 after Government Take	US$/t	26.4

6.1.5 Conclusions

The addition of CO_2 transport and injection facilities to the development of the Tangga Barat discovery would require additional capital costs of about US$220 million in US$2010 terms. The extra annual operating costs would be approximately US$8 million per year and the additional decommissioning costs would be about US$50 million incurred after a CO_2 injection period of 15 years.

Such a project would avoid emitting approximately 2.5 Mt/yr of CO_2-e to the atmosphere, which gives a total of 37.5 Mt over the assumed 15 years life of the project.

The specific cost of CO_2-e avoided is US$14 per tonne.

6.2 Natuna discovery

The Natuna gas field was discovered by Italy's Agip in 1973 and are located in the Greater Sarawak Basin about 1,100 km north of Jakarta and 225 km northeast of the Natuna Islands [40]. The field is in Indonesia's northernmost territory in the South China Sea at a water depth of 145 m. The Natuna discovery is the largest undeveloped gas discovery in Southeast Asia with an estimated resource of 46 Tcf of recoverable methane. We assume that this is at the 50% confidence level. However, this figure will need to be refined by further appraisal work [41].

In 2008, the Indonesian government awarded the Natuna block to Pertamina after cancelling former operator ExxonMobil's production sharing contract. However, it is possible that other companies would be joint venture partners with Pertamina in any development of the discovery.

Figure 20 shows the location of the Natuna discovery in Indonesia.

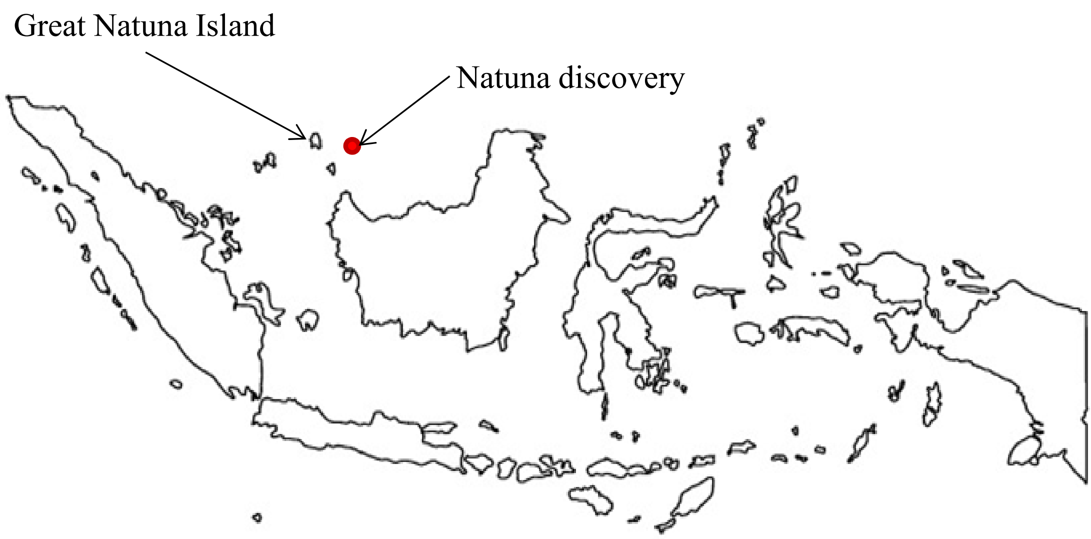


Figure 20 – The location of Natuna gas field in Indonesia

For the purpose of this analysis, we assume that the development of the Natuna discovery involves transporting the raw gas onshore to Great Natuna Island (Natuna Besar). At the onshore treatment plant the CO_2 is removed and compressed for transport. The purified methane gas is then liquefied at an LNG plant to be built on the island.

Pertamina has said that production of the Natuna discovery could start in 2017 provided that the plan of development is approved. At full capacity, the Natuna discovery could produce about 16 million tonnes per year of LNG. This corresponds to 690 Bcf per year (1,830 MMscf/d) of natural gas.

Table 20 describes the composition of the raw, sales and injected gas assumed for the analysis.

Table 20 – Composition of raw, sales and injected gas

Volumetric flow-rate (MMscf/d)	Raw gas	Sales gas	Inj. gas
Methane	1,393	1,393	0
Other hydrocarbons	348	348	0
CO_2	4,262	85	4,177
Total	6,003	1,826	4,177
Mass flow-rate (Mt/yr)	**Raw gas**	**Sales gas**	**Inj. gas**
Methane	9.8	9.8	0.0
Other hydrocarbons	4.6	4.6	0.0
CO_2	82.3	1.6	80.7
Total	96.7	16.0	80.7

6.2.1 Storage formation

The Natuna discovery is located in the East Natuna Basin in the Miocene Terumbu Formation. For the purpose of this study, we assume that CO_2 is injected into the Terumbu Formation below the Natuna discovery. The assumed injection site is located approximately 200 km from the project central processing facility on Great Natuna Island.

The middle Miocene to Lower Pliocene Terumbu Formation is the primary reservoir in the East Natuna Basin. The formation is composed of a series of platform and reefal carbonate build-ups. These carbonate build-ups are surrounded by tight fine-grained carbonates and shales deposited around their margins [63]. The reservoir quality in the build-ups is excellent. In this analysis, we assume an average porosity of 24% and an average permeability of 250 mD. The thickness of the formation varies from 300 m to over 1,525 m.

We have not obtained any data on the fracture pressure. For the purpose of this case study, we assume a constant fracture pressure gradient of 16 MPa/km.

Table 21 summarises the reservoir properties of the Terumbu Formation.

Table 21 – Storage formation properties

Variable	Units	Value	Notes
Economy		Indonesia	
Basin		East Natuna	
Formation/reservoir unit		Terumbu Formation	
Areal extent of formation	km^2	4,000 – 75,000	Assumed
Depth base seal	m	2,629	[63]
Formation thickness	m	300 – 1,525	Assumed
Injection depth	m RKB	3,429	Calculated
Porosity	%	24	Assumed
Permeability	mD	250	Assumed
Formation temperature	°C	171	[63]
Water depth	m SS	145	[63]
Formation pressure at injection depth	MPa	39.4	[63]
Fracture pressure at injection depth	MPa	54.9	Calculated
Fracture gradient	MPa/km	16.0	Assumed

The reservoir properties are clearly subject to large uncertainties and variations in them can have a significant effect on the injectivity, capacity and the results of the economic analysis. we do not warrant that, after taking the uncertainties into account, the formation has sufficient capacity to hold the volumes of CO_2 that would be emitted from the a development of the Natuna discovery. Therefore, estimating the number of wells required is highly uncertain. We assume that 90 wells are required for CO_2 injection. However, further appraisal will refine this number. Clearly, a lower areal extent and formation thickness could increase the required number of wells and the costs significantly.

6.2.2 CO_2 handling

For each of the cases we estimate the equipment sizes, the capital, operating and decommissioning costs, as well as the costs per tonne of CO_2-e avoided for CO_2 transport and injection. The costs are presented in US$2010 terms. They are based on limited cost and reservoir data and have a large margin of error. We have modelled only transport and injection economics and have not modelled the economics of capture or the sources emitting the CO_2.

The main assumptions and methods used for the analyses are listed below.

1. We assume that 98% of the CO_2 produced with the methane is captured and injected into the subsurface. Therefore 2% of the CO_2 emissions are not captured but are exported along with the methane. As a preliminary assumption, we assume separation using solvent absorption with a cryogenic polishing stage.
2. We assume that energy from a gas-fired power plant is used to provide the additional energy for all transport and injection operations including compression and auxiliary equipment. The power plant does not have CO_2 capture facilities. The power plant, compressor and auxiliary equipment are located on Great Natuna Island.

3. We assume an injection period of 75 years to calculate the costs of transport and injection. This corresponds to the expected life of the natural gas development.
4. We assume that the compressors' service lives are about 25 to 30 years – about one third of the project life. To take this into consideration, we increase the number of compressors for cost estimating purposes. We calculate that 10 compressor trains are needed to compress the injected gas. However, taking into account compressor sparing for a project life of 75 years, in total 25 compressors are purchased.
5. In all cases, the injected gas is compressed from capture conditions to a sufficiently high pressure (at least 8 MPa) to keep it in a supercritical state throughout the transport and injection stages. We estimate the compressor duty to be 203 MW.
6. The captured CO_2 is transported through three 1,050 mm parallel X70 carbon-steel pipelines with a maximum pipeline pressure of 18 MPa (2,610 psia). We assume that the pipelines carry the CO_2 200 km to the injection platforms. An alternative to this is separating the CO_2 offshore and transporting it a short distance to the injection sites. Separation offshore would be more expensive than separation onshore. However, transport would be less expensive. We have not analysed the trade-offs between offshore and onshore separation and transport.
7. The CO_2 is injected into the subsurface using 90 × 220 mm deviated wells from three steel jacket platforms.

6.2.3 Cost estimates

We estimate the total extra capital cost for CO_2 transport and injection to be US$5,975 million. Approximately 15% of the extra capital is spent on drilling wells. The annual extra operating cost is about US$180 million per year. At the end of the project the site is decommissioned at a real cost of approximately US$1,470 million. In Table 22 we report unit capital costs for major equipment items. More detailed results are provided in Table 23.

Table 22 – Summary of estimated unit costs of CO_2 transport and storage for Natuna

Items	Units	Source	Results
Unit Capital Costs			
Power plants	US$ million/MW	Estimated	0.4
Source compressor	US$ million/(Mt/yr)	Estimated	28.2
Pipeline	US$ thousand/km.mm	Estimated	2
Wells	US$ million/well	Estimated	10
Injection platforms	US$ million/platform	Estimated	156
Injection platforms	US$ million/slot	Estimated	5.2
Total extra capital cost	US$ million	Estimated	5,975
Annual extra operating cost	US$ million/yr	Estimated	176
Extra decommissioning cost	US$ million	Estimated	1,472
Specific cost of CO_2-e avoided	US$/t CO_2-e avoided	Estimated	7.6

The specific cost of CO_2-e avoided quoted in Table 17 is the net present value of the real costs divided by the net present value of the CO_2-e avoided over a 75 year injection period.

Table 23 – Detailed estimated costs of CO_2 transport and storage for Natuna

Items	Units	Source	Results
Total capital costs			
All power plants (1)	US$ million	Estimated	89
Source compressor machines (25)	US$ million	Estimated	2,272
Source compressor platforms (0)	US$ million	Estimated	–
Well-head compressor machine(0)	US$ million	Estimated	–
Well-head compressor platform(0)	US$ million	Estimated	–
Transport pipeline (3)	US$ million	Estimated	1,349
Inter-platform pipeline	US$ million	Estimated	–
Injection wells (90)	US$ million	Estimated	900
Injection platforms (3)	US$ million	Estimated	467
On costs	US$ million	Estimated	899
Total cost	US$ million	Estimated	5,975
Annual operating costs			
All power plants (1)	US$ million/yr	Estimated	44.7
Source compressor machines (25)	US$ million/yr	Estimated	90.9
Source compressor platforms (0)	US$ million/yr	Estimated	–
Well-head compressor machine(0)	US$ million/yr	Estimated	–
Well-head compressor platform(0)	US$ million/yr	Estimated	–
Transport pipeline (3)	US$ million/yr	Estimated	13.5
Inter-platform pipeline	US$ million/yr	Estimated	–
Injection wells (90)	US$ million/yr	Estimated	18.0
Injection platforms (3)	US$ million/yr	Estimated	9.3
On costs	US$ million/yr	Estimated	–
Total cost	US$ million/yr	Estimated	176.4
Total abandonment costs			
All power plants (1)	US$ million	Estimated	–
Source compressor machines (25)	US$ million	Estimated	568
Source compressor platforms (0)	US$ million	Estimated	–
Well-head compressor machine(0)	US$ million	Estimated	–
Well-head compressor platform(0)	US$ million	Estimated	–
Transport pipeline (3)	US$ million	Estimated	337
Inter-platform pipeline	US$ million	Estimated	–
Injection wells (90)	US$ million	Estimated	225
Injection platforms (3)	US$ million	Estimated	117
On costs	US$ million	Estimated	225
Total cost	US$ million	Estimated	1,472
Specific cost of CO_2-e avoided			
All power plants (1)	US$/t CO_2-e avoided	Estimated	0.6
Source compressor machine (25)	US$/t CO_2-e avoided	Estimated	3.2
Source compressor platform (0)	US$/t CO_2-e avoided	Estimated	–
Well-head compressor machine (0)	US$/t CO_2-e avoided	Estimated	–
Well-head compressor platform (0)	US$/t CO_2-e avoided	Estimated	–
Transport pipeline (3)	US$/t CO_2-e avoided	Estimated	1.4
Inter-platform pipeline	US$/t CO_2-e avoided	Estimated	–
Injection wells (90)	US$/t CO_2-e avoided	Estimated	1.0
Injection platforms (3)	US$/t CO_2-e avoided	Estimated	0.5
On costs	US$/t CO_2-e avoided	Estimated	0.8
Total cost	US$/t CO_2-e avoided	Estimated	7.6

6.2.4 Effects of fiscal terms

In Section 5 of this report, we discuss the effect of the fiscal terms on the economics of representative projects. Applying the same type of analysis to the Natuna development gives the results shown in Table 24.

Table 24 – Effect of fiscal terms on CO_2 transport and storage for Natuna

PV of CO_2-e avoided	Mt	692
Before-tax PV of all costs	US$ million	5,274
Before-tax cost of CO_2-e avoided	US$/t	7.6
Fiscal relief	%	58% – 76%
After-tax PV of all costs	US$ million	1,266 – 2,216
After-tax cost of CO_2-e avoided	US$/t	1.9 – 3.2
Minimum price of CO_2 before Government Take	US$/t	7.6
Minimum price of CO_2 after Government Take	US$/t	10.3

6.2.5 Conclusions

In our best estimate, the addition of CO_2 transport and injection facilities to the development of the Natuna discovery would require additional capital costs of about US$5,975 million in US$2010 terms. The extra annual operating costs would be approximately US$180 million per year and the additional decommissioning costs would be about US$1,470 million incurred after a CO_2 injection period of 75 years.

Such a project would avoid emitting approximately 80 Mt/yr of CO_2 to the atmosphere, which gives a total of about 6,000 Mt over the assumed 75 years life of the project.

We estimate that the specific cost of CO_2-e avoided is US$7.6 per tonne.

6.3 Papua New Guinea

The representative analyses discussed above do not include an analysis of CO_2 transport and storage in potential storage sites in Papua New Guinea (PNG). The principal reason for this is that current natural gas developments in PNG have very low or negligible CO_2 emissions.

The PNG LNG project currently being developed will tie together sources of natural gas in the Juha, Hides, Angore gas fields, and the gas associated with the Kutubu, Agogo, Moran and Gobe oil fields (Oil Search Annual Report 2009). With CO_2 representing just over 5% of the volume of raw gas, Juha has the by far the highest CO_2 content of all the sources of gas in the LNG project. Juha is the most remote of the sources of gas, is not planned to be tied in until later in the life of the LNG project and is expected to produce CO_2 at rates that will be very small in comparison to the volume of natural gas produced. Therefore, the small rate of CO_2 production is not expected to jeopardise the gas specifications for LNG production. We understand that, for these reasons, there are no plans to extract CO_2 from any gas developments linked to the LNG project. That includes any CO_2 from Juha. For the same reason, it is unlikely that sufficient CO_2 would be available from existing gas developments for enhanced oil or gas production in the existing oil or gas developments in PNG.

7 Regulations

This section considers the implications of environmental policies, legislation and regulations for CO_2 transport and storage activities in South-East Asia. Specifically, it considers:

- those parts of these environmental policies, legislation and regulation might positively assist in facilitating CO_2 transport and storage and how;
- those parts of these environmental policies, legislation and regulation might hinder CO_2 transport and storage and how; and
- the main omissions in the material that need to be addressed to facilitate CO_2 transport and storage.

To our knowledge, many of the CCS environmental issues (such as log-term liability for CO_2, surface rights, measuring, monitoring and verification requirements) that are being actively discussed in the USA, Canada, Australia and other economies are not given equivalent levels of attention in South-East Asia. For example, in Australia, it is intended that all CO_2 transport and storage projects will be subject to environmental assessment and approval in the relevant jurisdiction under the appropriate legislative regime.

7.1 Indonesia

7.1.1 Introduction

The Indonesian Government's environmental policies are established through the *Environmental Management Act 1997* and associated regulations and guidelines administered through the Ministry of Environment. The Ministry, however, lacks executorial and monitoring powers, which are still in the hands of sectoral departments or local authorities. The objective of the Act is stated as follows:

> *Environmental management which is performed with a principle of national responsibility, a principle of sustainability, and a principle of exploitation, aims to create environmentally sustainable development in the framework of the holistic development of the Indonesian human and the development of an Indonesian community in its entirety which is faithful and devoted to God the Almighty.*

A key feature of the policy is the need to prepare an Environmental Impact Analysis (EIA), which is required under Article 18 of the *Environmental Management Act 1997*. Every business which gives rise to a *"large and important impact on the environment"* must possess an EIA to obtain the licence to conduct a business and/or activity. It seems likely that CO_2 transport and storage activities would require an EIA.

EIA are requirements are considered further in Articles 19, 20 and 21 and include that:

> ***Article 19***
>
> 1. *In issuing a license to carry out a business and/or activity it is compulsory to take into account:*
>   a. *spatial management plans;*
>   b. *public opinion;*
>   c. *considerations and recommendations of authorized officials who are involved with such business and/or activity.*
> 2. *The license to conduct a business and/or activity decision must be made public.*

Article 20

1. *Without a licensing decision, every person is prohibited from disposing of waste to an environmental medium.*

2. *Every person is prohibited from disposing of waste which originates from outside Indonesian territory to an Indonesian environmental medium.*

3. *The authority to issue or refuse a licensing application as provided for in (1) above lies with the Minister.*

4. *Waste disposal to an environmental medium as provided for in (1) above may only be carried out at a disposal site which is determined by the Minister.*

5. *Implementing provisions for this Article are regulated further by government regulation.*

Article 21

Every person is prohibited from importing hazardous and toxic wastes.

More detailed regulations on EIAs and associated requirements (including requirements for an environmental management plan, environmental monitoring plan and a commission of assessment) are set out in *Government Regulation No. 27/1999*.

7.1.2 Regulations that might assist

The clearest assistance that can be provided by Indonesia's environmental policies, legislation and regulation that might positively assist in facilitating CO_2 transport and storage in Indonesia would be the ability to conduct an EIA and obtain a licence to operate under the *Environmental Management Act 1997*.

This would allow CO_2 transport and storage activities to proceed through consideration under the EIA process and potentially be approved for development. It should be noted that such a process, while vital to facilitating CO_2 transport and storage in Indonesia, would be secondary to establishing a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements.

7.1.3 Obstacles

Directly related to the section above, the major hindrance to CO_2 transport and storage arising from Indonesia's environmental policies, legislation and regulation is likely to be the fact that no CO_2 transport and storage activity has yet conducted an EIA and obtained a licence to operate under the *Environmental Management Act 1997*. First mover disadvantages may face the first project to do so.

It should be noted that such a process, while vital to facilitating CO_2 transport and storage in Indonesia, would be secondary to establishing a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements.

7.1.4 Omissions

While CO_2 transport and storage activities do not appear to be precluded by the *Environmental Management Act 1997,* it would appear that an overarching legislative and regulatory framework would need to be developed and implemented in Indonesia before such activities could proceed. Any necessary amendments to the *Environmental Management Act 1997* could be considered as part of this process.

7.2 Malaysia

7.2.1 Introduction

The Malaysian Government's environmental policies are established through the *Environmental Quality Act 1974* and associated regulations and guidelines. The objective of the Act is to promote environmentally sound and sustainable development. Investors are encouraged to consider the environmental factors during the early stages of their project planning. Aspects of pollution control include possible modifications in the process line to minimise waste generation, seeing pollution prevention as part of the production process, and focusing on recycling options.

A key feature of the policy is the need to prepare an Environmental Impact Assessment (EIA), which is required under section 34A of the *Environmental Quality Act 1974* for a list of activities set out in the *Environmental Quality (Prescribed Activities) (Environmental Impact Assessment) Order 1987*. According to the Malaysian Government, an:

EIA is a study to identify, predict, evaluate and communicate information about the impacts on the environment of a proposed project and to detail out the mitigating measures prior to project approval and implementation (Malaysian Government, Environmental Impact Assessment (EIA) Procedure and Requirements in Malaysia)

The list of prescribed activities do not directly include CO_2 transport and storage activities (although CO_2 pipeline transport may be captured by (b) below). Prescribed petroleum related activities include:

(a) Oil and gas discovery development.

(b) Construction of off-shore and on-shore pipelines in excess of 50 kilometres in length.

(c) Construction of oil and gas separation, processing, handling, and storage facilities.

(d) Construction of oil refineries.

(e) Construction of product depots for the storage of petrol, gas or diesel (excluding service stations) which are located within 3 kilometre of any commercial, industrial or residential areas which have a combined storage capacity of 60,000 barrels or more.

Even if the project is a non-prescribed activity, a Site Suitability Evaluation is required.

It is likely that any CO_2 transport and storage activities would need to be prescribed under the *Environmental Quality (Prescribed Activities) (Environmental Impact Assessment) Order 1987* before even being considered for approval for development in Malaysia. The rest of these sections proceed on the assumption that this is the case.

7.2.2 Regulations that might assist

The clearest assistance that can be provided by Malaysia's environmental policies, legislation and regulation that might positively assist in facilitating CO_2 transport and storage in Malaysia would be the inclusion of CO_2 transport and storage as a prescribed activity under the *Environmental Quality (Prescribed Activities) (Environmental Impact Assessment) Order 1987*.

This would allow CO_2 transport and storage activities to proceed through consideration under the EIA process and potentially be approved for development. It should be noted that such a process, while vital to facilitating CO_2 transport and storage in Malaysia, would be secondary to establishing a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements.

Malaysia also has in place a range of incentives for environmental management, some of which may be relevant to CO_2 storage and transport activities.

Specifically, the following activities may qualify for incentives:

- setting up proper facilities to store, treat and dispose of toxic and hazardous wastes. Companies that are directly involved in these three activities in an integrated manner qualify for:

- Pioneer Status, with income tax exemption of 70 per cent (100 per cent for promoted areas) of the statutory income for a period of five years. Unabsorbed capital allowances as well as accumulated losses incurred during the pioneer period can be carried forward and deducted from the post pioneer income of the company; or
- Investment Tax Allowance of 60 per cent (100 per cent for promoted areas) on the qualifying capital expenditure incurred within a period of five years. The allowance can be offset against 70 per cent (100 per cent for promoted areas) of the statutory income in each year of assessment. Any unutilised allowances can be carried forward to subsequent years until fully utilised.

- companies providing energy conservation services are eligible for the following incentives:
  - Pioneer Status with income tax exemption of 100 per cent of the statutory income for a period of ten years. Unabsorbed capital allowances as well as accumulated losses incurred during the pioneer period can be carried forward and deducted from the post pioneer income of the company; or
  - Investment Tax Allowance (ITA) of 100 per cent on the qualifying capital expenditure incurred within five years. The allowance can be offset against 100 per cent of the statutory income for each year of assessment. Any unutilised allowances can be carried forward to subsequent years until fully utilised.
- Companies using environmental protection equipment are eligible for an initial allowance of 40 per cent and an annual allowance of 20 per cent on the qualifying capital expenditure. Thus, the full amount can be written off within three years. These companies are:
  - Waste generators and wish to establish facilities to store, treat and dispose off their wastes, either on-site or off-site; and
  - Undertake waste recycling activities.
- In the case of companies that incur capital expenditure for conserving their own energy for consumption, the write-off period is accelerated by another one year.

It is important to note that CO_2 storage and transport activities are not currently eligible for these incentives, but it may be possible to mount a case for their inclusion.

7.2.3 Obstacles

Directly related to the section above, the major hindrance is the fact that CO_2 transport and storage is not listed as a prescribed activity under the *Environmental Quality (Prescribed Activities) (Environmental Impact Assessment) Order 1987* and therefore unable to proceed through the EIA process. This is likely to represent a significant impediment to moving forward with CO_2 transport and storage activities in Malaysia.

As with the section above, it should be noted that such a process, while vital to facilitating CO_2 transport and storage in Malaysia, would be secondary to establishing a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements.

7.2.4 Omissions

The main omission relates to the omission of CO_2 transport and storage as a prescribed activity under the *Environmental Quality (Prescribed Activities) (Environmental Impact Assessment) Order 1987*.

The treatment of CO_2 transport and storage under the *Environmental Quality Act 1974* should be seen as an element of the legislative and regulatory framework that would need to be developed and implemented in Malaysia before such activities could proceed.

In addition, consideration could be given to including CO_2 storage and transport activities as eligible for one or more environmental incentives in Malaysia.

7.3 Vietnam

7.3.1 Introduction

The Vietnam Government's environmental policies are established through the *Law on Environmental Protection (1993)* and associated regulations and guidelines and administered by the Ministry for Natural Resources and the Environment. The objective of the Law is to provide environmental protection, including

> *... activities aimed at preserving a healthy, clean and beautiful environment, improving the environment, ensuring ecological balance, preventing and overcoming adverse impacts of man and nature on the environment, making a rational and economical exploitation and utilisation of natural resources.*

A key feature of the policy is the need to prepare and consider a Strategic Environmental Assessment (SEA), an Environmental Impact Assessment (EIA) or an Environmental Protection Commitment.

SEA requirements are set out in Chapter III, Article 16 of the *Law on Environmental Protection (1993)* and must comprise:

> ***Article 16 — Contents of strategic environmental assessment reports***
>
> 1. *Overview of the project's objectives, size and characteristics related to the environment.*
> 2. *General description of natural, socio-economic and environmental conditions related to the project.*
> 3. *Forecasts for possible bad environmental impacts when the project is executed.*
> 4. *Citation of sources of figures and data, methods of assessment.*
> 5. *Proposed orientations and measures to address environmental issues during project execution.*

EIA requirements are set out in Chapter III, Article 18 of the *Law on Environmental Protection (1993)*. The EIA involves:

> *... the process of analysing, evaluating and forecasting the effects on the environment by socio-economic development projects and plans, by production and business establishments, and economic, scientific, technical, medical, cultural, social, security, defence or other facilities, and proposing appropriate solutions to protect the environment.*

The Vietnamese Government promulgates a list of activities for which EIAs are required. CO_2 transport and storage is not currently a listed activity. It is likely that any CO_2 transport and storage activities would need to be included in this list before even being considered for approval for development in Vietnam. The rest of these sections proceed on the assumption that this is the case.

Household-based production, business or service establishments and entities not defined in Articles 14 and 18 of the *Law on Environmental Protection (1993)* must make written environmental protection commitments. Such commitments involve *"measures to minimise and treat wastes and strictly comply with the provisions of law on environmental protection"* and are generally for small-scale activities.

7.3.2 Regulations that might assist

The clearest assistance that can be provided by Vietnam's environmental policies, legislation and regulation that might positively assist in facilitating CO_2 transport and storage in Vietnam would be the inclusion of CO_2 transport and storage as a listed activity under the *Law on Environmental Protection (1993)*.

This would allow CO_2 transport and storage activities to proceed through consideration under the SEA and EIA processes and potentially be approved for development. It should be noted that such a process, while vital to facilitating CO_2 transport and storage in Vietnam, would be secondary to establishing a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements.

7.3.3 Obstacles

Directly related to the section above, the major hindrance is the fact that CO_2 transport and storage is not listed as an activity under the *Law on Environmental Protection (1993)* and therefore likely to be unable to proceed through the SEA and EIA processes. This is likely to represent a significant impediment to moving forward with CO_2 transport and storage activities in Vietnam.

As with the section above, it should be noted that such a process, while vital to facilitating CO_2 transport and storage in Vietnam, would be secondary to establishing a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements.

7.3.4 Omissions

The main omission, then, relates to the omission of CO_2 transport and storage as an activity promulgated under the *Law on Environmental Protection (1993)*.

The treatment of CO_2 transport and storage under the *Law on Environmental Protection (1993)* should be seen as an element of the legislative and regulatory framework that would need to be developed and implemented in Vietnam before such activities could proceed.

In addition, consideration could be given to including CO_2 storage and transport activities as eligible for one or more environmental incentives in Vietnam.

7.4 Thailand

7.4.1 Introduction

The Thailand Government's environmental policies have been established through the *National Environmental Quality Act 1992 (NEQA 1992)* and associated regulations and guidelines. The objective of this Act is to reform and improve the law on enhancement and conservation of national environmental quality.

A National Environment Board sets environmental quality standards and gives approval to various plans and standards proposed by other regulatory bodies or organisations. Aspects of pollution control include constructing or installing facilities for controlling and treating waste water discharge, polluted air emissions and discharge of other wastes or pollutants.

Projects or activities likely to have environmental impact are required to prepare reports on environmental assessment. The reports are referred to as Environmental Impact Assessment (EIA) reports. The legal framework for EIA is set out in Part 4 in Chapter III in the *National Environmental Quality Act 1992*. The types and sizes of projects or activities are specified by *Notification No. 3/92* published in the Government Gazette.

Upstream activities including constructing onshore and offshore pipelines are subject to a full EIA report. For seismic surveys and exploration drilling, it is usually sufficient to provide an initial environmental evaluation.

The activities identified in the *Notification No. 3/92* do not directly include CO_2 transport and storage activities, although it is possible that CO_2 pipeline transport is included.

It is likely that CO_2 transport and storage activities will need to be identified in the notification before even being considered for approval for development.

7.4.2 Regulations that might assist

Thailand's environmental policies, legislation and regulation might positively assist in facilitating CO_2 transport and storage in Thailand if they include CO_2 transport and storage as a prescribed activity in *Notification No. 3/92*.

This would allow CO_2 transport and storage activities to be considered under the EIA process and potentially be approved for development. This process is vital to facilitating CO_2 transport and storage. However, it would be more important to establish a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements.

According to Section 68 of the *NEQA 1992,* the owner or operator of a point source of air pollution has the duty to install or bring into operation facilities for air pollution control in order to reduce or eliminate pollutants which may affect air quality. This would urge companies to implement CO_2 transport and storage activities if CO_2 emissions from natural gas developments are deemed as emissions of polluted air described in the emission standards. The *NEQA 1992* authorises Ministry of Natural Resources and Environment to regulate point sources of pollution and introduce atmospheric ambient air standards.

Thailand also has in place a range of support and assistance measures for environmental management, some of which may be relevant to CO_2 storage and transport activities.

Specifically, the following activities are qualify for government support and assistance —

- Installing facilities for treating polluted air or wastewater or for disposal of any other wastes including procurement of equipment, instrument tools, appliances or materials necessary for control of pollution. Companies involved in these activities can request assistance from the government service in the following matters -
  - Importing necessary machinery equipment instrument tools, appliances or materials which are not available in Thailand
  - Bringing foreign experts or specialists into Thailand to carry out works concerning the installation, monitoring control or operation of air pollution control systems, wastewater treatment works or waste disposal facilities.

- Income tax exemptions for work involving supervising foreign experts or specialists.

CO_2 storage and transport activities are not currently eligible, but it may be possible to make a case for their inclusion.

7.4.3 Obstacles

Directly related to the section above, the major impediment is the fact that CO_2 transport and storage is not a prescribed activity in the government notifications. Therefore it cannot proceed through the EIA process. This is likely to hinder CO_2 transport and storage activities.

As with the section above, including CO_2 transport and storage provisions in the EIA would facilitate CO_2 transport and storage. However, it would be secondary to establishing a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements.

National ambient air quality standards are set out in *Notification of National Environmental Board No. 28, B.E 2550 (2007)*. However, oil and gas exploration and production atmospheric emission standards have not been prescribed. In general industrial atmospheric emission standards, CO_2 emissions are not considered as emissions of polluted air and there are no regulations directly related to their control or treatment.

7.4.4 Omissions

The main omission relates to the omission of CO_2 transport and storage as a defined activity in the government Notifications.

The treatment of CO_2 transport and storage under the *National Environmental Quality Act 1992* should be seen as an element of the legislative and regulatory framework. Such framework would need to be developed and implemented before any CO_2 transport and storage activities could proceed.

In addition, consideration could be given to including CO_2 storage and transport activities as eligible for environmental incentives.

7.5 Brunei

7.5.1 Introduction

Brunei has no framework legislation concerning the environment. Environmental issues are regulated by existing sectoral laws governing various economic activities. However, there is an environmental policy. It has the following objectives -

- *To maintain sustainable utilisation of natural resources.*
- *To minimise negative impacts on environment arising from population growth and human activities.*
- *To achieve balanced goals of socio-economic development and sound environmental quality.*

The most important laws related to environmental issues are listed below.

- *Petroleum Mining Act, amended 1992 (Chapter 44)*
- *Petroleum (Pipelines) Act (Chapter 45)*
- *Mining Act (Chapter 42)*
- *Forest Act (Chapter 46)*
- *Water Supply Act (Chapter 12)*
- *Land Code (Chapter 40)*
- *Poison Act (Chapter 114)*
- *Ports Act, amended 1988 (chapter 144)*
- *Town and Country Planning (Development Control Act (Chapter 142)*

There is no single Ministry or Department in Brunei which is specifically responsible for environmental issues. Such responsibilities are divided among different ministries, departments and units.

There are two institutions which play important roles in coordinating environmental policies. These are the National Committee on the Environment (NCE) and the Environmental Unit of the Ministry of Development. The NCE is a high-level inter-agency consultative body. Its responsibilities are to look into environmental issues, review environment related legislation and give advice for environmental plans and guidelines. It coordinates environmental policy-making, provides an overall framework for environmental management and oversees the implementation of national environmental activities, legislation and policies related to the environment.

Brunei does not yet have specific laws requiring Environmental Impact Assessments (EIAs). The draft EIA regulation is yet not approved. However, in principle the Government requires EIAs for large and heavy industries such as in the ammonia/urea, methanol and aluminium smelter plants currently being planned. New industries also need to submit plans indicating measures to be taken to reduce environmental impacts.

Brunei Shell has formulated its own Environmental Management Plan. The plan includes practices, procedures and standards related to air quality, water quality and waste management. The plan also includes monitoring programmes, EIA procedures and environmental audits. It is likely that any CO_2 transport and storage activities would need to submit EIAs or plans before being considered for approval for development in Brunei.

7.5.2 Regulations that might assist

Parts of Brunei's environmental policies, legislation and regulations might positively assist in facilitating CO_2 transport and storage in Brunei. For instance, the ability to conduct an EIA and submit development plans to obtain approval from the Government would be important. This would allow CO_2 transport and storage activities to be approved for development under the EIA process. While the EIA process is vital to facilitating CO_2 transport and storage, establishing a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements are more important in the first instance.

7.5.3 Obstacles

Directly related to the section above, the major obstacle to CO_2 transport and storage arising from Brunei's environmental policies, legislation and regulation is likely to be the fact that no CO_2 transport and storage activity has yet conducted an EIA and obtained a licence to operate.

The EIA process is vital to facilitating CO_2 transport and storage in Brunei. However, it should follow the implementation of a legislative and regulatory framework for CO_2 transport and storage activities, including titling and permitting arrangements.

In addition, there are no specific laws to regulate air quality. There are some brief provisions in various laws and regulations that deal with air pollution, but these are largely lack of detail. Therefore there are no regulations in place that deal specifically with CO_2 emissions.

7.5.4 Omissions

While CO_2 transport and storage activities do not appear to be in any of the environmental legislation, it appears that an overarching legislative and regulatory framework would need to be developed and implemented in Brunei before such activities could proceed.

One possible method would be to enact comprehensive environmental framework legislation. This framework should tie together the environmental issues which are currently covered by sectoral laws. More detailed regulations on specific matters such as CO_2 transport and storage can then be included as subsidiary legislations. The existing EIA procedures will also need to be improved. Specific guidelines, regulations and standards will need to be enacted.

In addition, consideration could be given to providing incentives for new industries such as CO_2 transport and storage.

8 Conclusions and recommendations

The results of this study suggest that, depending on any future carbon price and fiscal policies, there is significant potential for transport and injection of CO_2 emitted from natural gas field developments in South-East Asia. A significant number of projects are likely to be viable with a carbon price up to US$20 per tonne in real terms ignoring the effects of the fiscal terms that operate across the region and up to US$60 per tonne in real terms assuming that the fiscal terms that apply to gas field developments also apply to CO_2 transport and injection projects.

However, this study is based on limited high-level data and therefore the findings are only broadly indicative. More detailed project-specific studies are required. In addition, realising the potential for CO_2 sequestration requires more work in establishing the economic, fiscal and regulatory environment in which such projects could be developed.

We recommend further study based on more specific data on actual gas field developments and potential storage sites, particularly depleted or depleting fields for which data is plentiful. Depending on the circumstances, this might involve a study of enhanced oil or gas recovery in addition to CO_2 storage. In our view, such a study would first require obtaining the cooperation of oil and gas companies in the region and then working closely with them. The study is likely to proceed in stages. First it would involve contacting companies at a high level to gauge their level of interest in collaborating in such a study. Then it would involve negotiating agreements with interested companies to determine the terms of reference before the study begins. Finally, it would involve preparing the study with the close cooperation of the interested companies.

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Appendix 1 Invitation to tender

Asia-Pacific
Economic Cooperation

Request for Proposals

EWG 06/2008A

Assessment of the Capture and Storage Potential of CO_2 Co-Produced with Natural Gas in South-East Asia

Further assistance regarding this Request for Proposals may be obtained from:

Dr. Frank Mourits
Natural Resources Canada
Phone: +1-613-947-3482
Fax: +1-613-995-6146
Email: fmourits@nrcan.gc.ca

Lodgment of Tenders to:
Mr. Sun Tao APEC Secretariat 35, Heng Mui Keng Terrace Fax - 65-6891-9690 Email: st@apec.org (Reference EWG09/2008A)
Closing Time and Date: 5.00 pm, Singapore time, Friday, 27 March 2009

Request for Proposals

This request for proposals is for a consultancy to assess the techno-economic feasibility of reducing carbon dioxide (CO_2) emissions resulting from natural gas production in South-East Asia through carbon capture and storage (CCS) technologies, specifically by re-injecting the gas into subsurface geological formations. The project will explore potential near-term opportunities for commercially viable CCS and present at least two case studies that will demonstrate how CCS technologies could be applied in natural gas production operations in the South-East Asian region.

The main output of this consultancy will be a report providing guidance, especially for APEC developing economies in South-East Asia, on the technical, economic and other aspects of re-injecting CO2 produced during natural gas production into depleted oil or gas reservoirs, or deep saline formations. The report will include:

- Assessment of the capital and operating costs to re-inject the CO2 separated during natural gas production, including transportation if the storage site is remote from the production site;
- Identification and analysis of specific CCS-related issues;
- Assessment of the potential benefits in the form of enhanced oil or gas production and reduced greenhouse gas emissions;
- Conclusions and recommendations for potential widespread applications in the South-East Asian region.

The project will be conducted in consultation with a Project Steering Committee, made up of the Project Overseer and members of the APEC Expert Group on Clean Fossil Energy (EGCFE), augmented, where needed, with government and industry representatives from the project region. In order to ensure that the project meets APEC Energy Working Group (EWG) expectations and follows APEC project guidelines, the Project Steering Committee will be actively involved throughout the project, including in consultant selection, final project definition, evaluation of the results and review of the draft report.

Background

In order to meet their future energy needs, developing APEC economies are anticipated to sharply increase their consumption of predominantly fossil fuel energy. As a result, carbon dioxide emissions from energy production and use in the APEC region are forecast to rise by 60 per cent between 1999 and 2020. Technologies to store (or sequester) CO_2 in geological formations have the potential to provide a viable, medium-term option for developing APEC economies to retain the benefits of deriving energy from low-cost fossil fuels, such as coal, while at the same time reducing CO2 emissions to the atmosphere and, thus, promoting environmentally sustainable growth.

There is a sense of urgency, which was highlighted by the International Energy Agency (IEA) in their 2004 statement that “governments need to take action now to ensure that CCS technologies are developed and deployed on a large scale over the next few decades”. This urgency was again emphasized by G8 Leaders in July 2008, who, at their summit meeting in Hokkaido, Japan, declared that they “strongly support the launching of 20 large-scale CCS demonstration projects globally by 2010, taking into account various national circumstances, with a view to beginning broad deployment of CCS by 2020”.

There are presently significant efforts in progress in the area of CCS in Australia, Canada, the European Union, Japan, Norway, the United States and other industrialized economies across the world. The deployment of CCS is at varying stages of implementation, and a number of demonstration or commercial projects are operating, under way or being planned. In addition, numerous CCS feasibility studies are being carried out by the IEA Greenhouse Gas R&D Programme, the Carbon Sequestration Leadership Forum (CSLF) and many other organizations.

A significant source of CO_2 emissions in South-East Asia is the production of natural gas (e.g., Thailand, Vietnam, Malaysia and Indonesia). The raw gas often contains considerable quantities (e.g., 25%) of CO_2, which is currently separated and released into the atmosphere – thus contributing to climate change and global warming. As an example, more than half a million tonnes of CO_2 annually is released from natural gas produced in the Gulf of Thailand alone. Fortunately, opportunities may exist to re-inject the CO_2 into subsurface geological formations, either into partially depleted oil or gas reservoirs or into deep saline formations.

The use of captured CO_2 for injection into partially depleted oil or gas reservoirs to enhance the recovery of the remaining oil or gas is a near-term storage option, which has found widespread application in the United States and is increasingly practiced in Canada and other parts of the world. The storage of CO_2 into deep saline formations is generally seen as a somewhat longer-term option with very large storage potential. This technology is being considered or demonstrated in a growing number of projects around the world. Examples of large, commercial-scale natural gas production operations with CO_2 geological storage include the Sleipner and Snøhvit projects in Norway, the In-Salah project in Algeria and the Gorgon project in Australia.

Building on this body of experience and knowledge of injecting and storing CO_2 in subsurface formations, this study will look at the applicability of the above two storage options to gas production operations in South-East Asia and assess their techno-economic feasibility. It is expected that an earlier APEC assessment study of the geological storage potential of CO_2 in APEC economies (Phase I – EWG 06/2003), which showed that suitable geological formations exist in the South-East Asian region, can be utilized as a useful screening tool. It is further anticipated that local geological services and the natural gas producers in the study areas may be asked by the consultant to furnish some of the site-specific geological and operational information that will be needed for the feasibility study. It will be beneficial to establish a good working relationship with the producers, as it will be important to hear their views on the concept of re-injecting CO_2 and any operational issues they may anticipate.

Objectives

The main objective of the project is to assess the techno-economic feasibility of reducing CO_2 emissions resulting from natural gas production in South-East Asia through the application of CCS technologies, specifically by re-injecting the gas into subsurface geological formations. The project will explore potential near-term opportunities for commercially viable CO_2-enhanced oil or gas recovery, and the longer-term storage of CO_2 in deep saline formations. At least two case studies will be presented to demonstrate how CCS could be applied to natural gas production operations in the South-East Asian region. The project will produce a report providing guidance, especially for developing APEC economies in South-East Asia, on the technical, economic and other issues related to re-injecting CO_2 from natural gas production into depleted oil or gas reservoirs or deep saline formations.

A secondary objective of the project is a combination of promoting awareness, building capacity and developing human capital in the discovery of CCS. By being exposed to and/or involved in the geological assessments and CCS technology evaluation methodologies being carried out by the consultant for specific sites in their own economies, decision makers from government and industry will be "learning by doing". They may become involved by taking part in the study itself, attending debriefs throughout the study or participating in a workshop at the conclusion of the study. Through the transfer of CCS technology knowledge and expertise, local capacity will be developed and/or strengthened. This knowledge base will become the foundation for follow-on CCS work that the developing economies may want to initiate as they are pursuing their long-term energy sustainability goals. In circulating the final report of the project, and as part of workshop presentations, recipients and participants will be asked to complete a survey, so they can give their views on the content and utility of the report, the benefits they expect to derive from it, and the degree to which the project contributed to building awareness of and capacity in CCS in the recipients' economy.

The project will build on the successful CCS work the EGCFE has carried out since 2003, which includes exploring the potential of CO_2 subsurface storage (geological sequestration) in APEC economies (Phase I – EWG 06/2003); developing training materials for use in CCS training workshops (Phase II – EWG 02/2004); and hosting two capacity-building and technology transfer workshops in China and Mexico (Phase III – EWG 07/2005). Reports on these projects are available at http://www.ewg.apec.org/.

Scope of Work

The project will be carried out and completed by 31 December 2009 by a consultant with appropriate oil and gas production expertise, a thorough understanding of the issues involved in CCS, and specific knowledge and expertise of the technologies and economics of CO_2 injection and storage. The consultant will work closely with local governments and the oil and gas companies operating in South-East Asia, both of which are expected to be the main sources of the geological and technical data that will be required. A Project Steering Committee, comprising the Project Overseer, EGCFE experts and government and industry representatives from the project regions, will provide guidance at appropriate stages. In-kind industry support will be sought.

The project will include the following staged activities:

1. Data Collection
   - review the experiences to date in APEC and OECD economies, the International Energy Agency, and by other relevant international bodies with respect to the technical, operational, economic, regulatory and other challenges facing the re-injection of CO_2 produced in natural gas production operations;
   - identify and collect data on major natural gas production facilities in developing APEC economies in the South-East Asian region. Potential economies to be included are: Brunei Darussalam, Indonesia, Malaysia, Papua New Guinea, Philippines, Thailand and Viet Nam). A final selection will be made in consultation with the Project Steering Committee;
   - obtain required geological data from natural gas producers, the geological services of the APEC economies included in the study, or any other relevant sources;
2. Analysis, Evaluation and Assessment
   - identify and assess potential suitable CO_2 storage reservoirs in the proximity of the natural gas production sites;
   - develop an estimate of the capital and operating costs to re-inject the CO_2 separated during natural gas production, including pipelining if the storage site is more remotely located from the production site;
   - estimate the potential revenues from enhanced oil or gas production;
   - estimate the potential greenhouse gas emission reductions resulting from the re-injection of CO_2 produced in natural gas production operations;
     - prepare at least two case studies exemplifying the challenges and benefits of re-injecting CO_2 from natural gas production (one study to include enhanced oil or gas recovery; the second to be limited to direct CO_2 injection);
     - identify and analyze specific CCS-related issues and/or barriers, including but not limited to: S technical issues; S legal and regulatory issues; S commercial and financial issues; S safety, environmental and security issues; S public information and consultation issues; S potential CDM (Clean Development Mechanism) opportunities.
     - prepare conclusions and recommendations with respect to potential applications of this CCS technology in the APEC economies included in the study and beyond the region.
3. Reporting and Presentations
   - complete a preliminary draft final report and submit it for comments and approval to the Project Steering Committee;
   - taking into account the comments and suggestions provided by the Project Steering Committee, present the results, conclusions and recommendations at an appropriate regional workshop and/or the annual APEC EGCFE Technical Seminar (Korea, October or November 2009);
   - in circulating the preliminary draft final report and as part of the workshop presentation, conduct a survey and request feedback on:

- appropriateness of the methodologies used;
- degree to which the report provides new and relevant insights;
- degree to which the results may be used by government and industry decision-makers when considering options to reduce CO_2 emissions in their economy;
- degree to which the project contributed to building awareness of and capacity in CCS.

- incorporating the comments and suggestions previously provided by the Project Steering Committee and including the feedback received from the workshop and the results of the survey, finalize the draft report, ensuring that editing and formatting meet high professional standards and comply with APEC style and nomenclature guidelines, and submit it to the Project Steering Committee for final approval
- submit electronic copies (MS Word and PDF formats) of the approved final report on CD-ROM to the Project Overseer and the APEC and EWG Secretariats by 31 December 2009.

Timetable and Deliverables

The following timetable for the completion of the project is suggested. The consultant may propose an alternative schedule as long as the project is completed by the end of 2009.

	Activity	Deadline
1	Issuance of RFP	27 February 2009
2	Deadline for submission of Proposals to APEC Secretariat	27 March 2009
3	Consultant selected and recommendation referred to APEC Secretariat for contract negotiations	6 April 2009
4	Contract awarded by APEC Secretariat	April 2009
5	Data collection	May-July 2009
6	Analysis, evaluations and assessments	June-September 2009
7	Preliminary draft final report submitted to Project Steering Committee for review and approval	October 2009
8	Workshop presentation	October-November 2009
9	Draft final report submitted to Project Steering Committee for review and approval	30 November 2009
10	Final report completed and submitted to Project Overseer and APEC/EWG Secretariats	31 December 2009
NOTE: The project must be completed with all monies disbursed by 31 December 2009		

Qualifications of the Consultant

Consultants wishing to tender for this project should present a proposal to the APEC Secretariat by close of business on 27 March 2009. The Proposal should include evidence of ability and experience to undertake the specified tasks in this Request for Proposal, specifically:

an outline of all project activities, sufficiently detailed to demonstrate that the consultant:

(a) has a clear understanding of the tasks and methodologies to be applied;

(b) has original suggestions that can improve the study and ensure a quality product;

(c) can complete the work efficiently and provide deliverables on time and on budget;

1. evidence of a high level of technical and business knowledge of and expertise with oil and natural gas production operations; experience with such operations in developing APEC economies would be an asset;

2. evidence of in-depth knowledge of and experience with CCS, in particular with respect to the injection and geological storage of CO_2;

3. familiarity with the issues affecting the potential of CCS, including technical, economic, legal and regulatory issues, and with impediments to the uptake of CCS;

4. prior evidence of the capability to deliver high-quality projects and outputs on time and within budget;

5. evidence of familiarity with and/or having contacts in the oil and gas industry carrying out natural gas production operations in South-East Asia, and with local government agencies involved in decision-making in the area of energy supply and environmental protection.

The consultant should provide a Résumé for each person proposed to participate in the project. When reviewing proposals, specific attention will be given to qualified women proposed by the consultant to work on the project. It will be important to involve women in the organization of the workshops as well as the management of the project and preparation of the final report. The proposal should adhere to the priorities of the Framework for the Integration of Women in APEC ("Accelerate the progress of integrating women in the mainstream of APEC processes and activities" and "Promote and encourage the involvement of women in all APEC fora").

Budget

The total approved budget for this study is up to US$185,010, including US$85,010 from APEC funding and up to US$100,000 (not open for bidding) from anticipated in-kind support by Canada, the oil and gas industry, and local governments. This budget is consistent with the anticipated costs of carrying out the required work and preparing/completing the final report, including all associated costs (labor, fees, travel, etc.).

The consultant will prepare an itemized budget (up to US$68,000) and submit this with the proposal. This budget must include:

- Consulting fees, including contractor and subcontractor (where required) fees;
- Consultant's secretary cost and other administrative costs associated with the project.

Funding for travel, publication, photocopying and telecommunication costs (US$17,010) will be handled and be reimbursed by the APEC Secretariat, subject to signature of travel undertaking and submission of relevant invoices. It is anticipated that the consultant will need to travel up to three times to Asia, including travel for the workshop presentation.

http://www.apec.org/apec/publications/free_downloads/2002.MedialibDownload.v1.html?url=/etc/medialib/apec _media_library/downloads/taskforce/aggi/pubs/2002.Par.0003.File.v1.1

The self-financed portion of the project reflects self-funding by Canada for project oversight and management, and the anticipated in-kind support from the oil and gas industry operating in the South-East Asian region and local government agencies. This in-kind support covers the provision of geological data, operational/production data and other pertinent information, as well as staff time to discuss the emerging results on a regular basis.

Proposal Information

Inquiries on this request for proposals should be addressed to:

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E-mail: st@apec.org

Conditions of the RFP

The detailed conditions of this RFP are listed in the attachment.

Attachment

Conditions of this Request for Proposals

1. APEC PREFERENCE PROGRAM

It is the policy of APEC to award contracts to firms from Member Economies when this can be done consistent with an expectation of efficient performance of the Contract, at prices no higher than are obtainable elsewhere, and which can be done without restricting competition. If subcontractors are used, the Contractor shall use its best efforts to place subcontracts in accordance with this policy.

2. ASSIGNMENT

Assignment of the Contract or any benefit arising there under or any interest therein will be grounds for terminating the Contract at the option of the APEC Secretariat.

3. CHANGES TO SCOPE OF CONTRACT

The terms of the Contract may be varied only by written agreement between the APEC Secretariat and the Contractor.

4. CONTRACTOR LIABILITY FOR PERSONAL INJURY AND/OR PROPERTY DAMAGE

The Contractor indemnifies and holds harmless the APEC Secretariat for loss or damage or injury suffered by any person, however and wherever caused, by the Contractor, its employees, agents and contractors during the performance of the Contract.

5. DEFAULT

5.1. In the event of a Default by the Contractor, the APEC Secretariat shall write to the Contractor setting out the Default. If the Contractor fails to remedy the Default within the time specified in writing by the APEC Secretariat, the APEC Secretariat may forthwith terminate the Contract without prejudice to the rights of any parties accrued to the date of termination.

5.2. A Default means any breach of a condition of the Contract or any substantial breach of a warranty in the Contract, including, but not limited to:

- failure to perform the Contract within the agreed time, or
- failure to deliver equipment of adequate capability, quality or reliability.

6. DISPUTES

In the event of any dispute concerning the meaning to be given to any term in the Contract, a determination by the APEC Secretariat in writing as to the meaning shall be final and conclusive.

7. EXAMINATION OF RECORDS

The APEC Secretariat, or its designated representative, shall have access to the Contractor's directly relevant books, documents, papers, and other records involving transactions related to the Contract. This access shall commence from the date of signing of the Contract and shall continue for a period of 3 years following the completion of the Contract.

8. RIGHTS IN DATA -GENERAL

The APEC Secretariat shall be deemed the owner of, and shall be deemed to have full rights (including copyright) in all data, regardless of form, format, or media, resulting from performance of the Contract, all data regardless of form, format, or media, used in performing the Contract; all data delivered under the Contract constituting manuals or instructional and training material; all processes delivered or furnished for use under the Contract; and all other data delivered under the Contract.

Subject to the prior written approval of the Executive Director of the APEC Secretariat ("the Executive Director"), the Contractor may have the right to use, release to others, reproduce, distribute, or publish any data first produced or specifically used by the Contractor in the performance of the Contract. For example, the information may be used to promote economic development with any benefits accruing to the originator.

The APEC Secretariat may deliver to the Contractor data necessary for the performance of the Contract. Title to APEC Secretariat furnished data remains with the Secretariat. The Contractor must use any data which it receives from the APEC Secretariat only in connection with the Contract.

To the extent it receives or is given access to data necessary for the performance of the Contract which contains restrictive markings, the Contractor shall treat the data in accordance with such markings unless otherwise specifically authorized in writing by the Executive Director.

The Contractor shall not disclose any information received or generated under the Contract, unless its release is approved in writing by the Executive Director and shall assert any privilege allowed by law to defend vigorously the APEC Secretariat's rights to confidentiality.

9. SUSPENSION OF WORK

The Executive Director may, at any time, by written order to the Contractor, suspend all, or any part, of the work, if any, being carried out by the Contractors, its officers, employees, agents or subcontractors, for a period of up to 90 days after the order is delivered to the Contractor, and for any further period as the circumstances may require at the discretion of the Executive Director. Upon receipt of the order, the Contractor shall immediately comply with its terms and take all reasonable steps to minimize the costs incurred by the stoppage relevant to the work covered by the order. Any associated adjustment to the Contract price and/or time for completion will be negotiated between the Executive Director and the Contractor.

10. TERMINATION FOR CONVENIENCE OF THE SECRETARIAT

The Executive Director, by written notice and without giving any reasons therefore, may terminate this Contract, in whole or in part as he sees fit by issuing a Notice of Termination. If this Contract is terminated, the rights, duties, and obligations of the parties, including compensation to the Contractor, shall be negotiated between the Executive Director and the Contractor, but in no event shall it exceed the total value of the Contract.

After receipt of a Notice of Termination and except as directed by the Executive Director, the Contractor shall immediately stop work as specified in the notice. After termination, the Contractor shall submit a final termination settlement proposal to the Executive Director in the form and with the certification prescribed by the Executive Director. If the Contractor fails to submit the termination settlement proposal within the time allowed, the Executive Director may determine, on the basis of information available, the amount, if any, due to the Contractor because of the termination and shall pay the amount so determined.

11. LANGUAGE

All drawings, documents, information, correspondence, test reports and such like items shall be in the English language.

Appendix 2 GTL through CO_2/steam reforming

A review of the CO_2/steam reforming process from basic chemical equations is worthwhile as an initial exercise to understand better the published data.

The process is summarised in the following equilibrium reactions that result in the production of syngas (a mixture of hydrogen and carbon monoxide).

$$CH_4 + CO_2 \leftrightarrows 2H_2 + 2CO \quad (3)$$

$$CH_4 + H_2O \leftrightarrows 3H_2 + CO \quad (4)$$

Equation (3) results in an H_2:CO molar ratio of 1:1 and Equation (4) gives a ratio of 3:1.

There is another reaction involved that affects the H_2:CO molar ratio. This is the water gas shift reaction -

$$CO + H_2O \leftrightarrows H_2 + CO_2 \quad (5)$$

An H_2:CO molar ratio of 2:1 is required to convert syngas into paraffinic syncrude using the Fischer-Tropsch process. This is described by the equation below.

$$2nH_2 + nCO \leftrightarrows \frac{1}{n}(CH_2)_n + nH_2O \quad (6)$$

$\frac{1}{n}(CH_2)_n$ represents the Fischer-Tropsch product called syncrude. This product is a mixture of paraffins of carbon chain lengths n, ranging from 5 to 100. This product is upgraded by separation into saleable GTL products, namely Naphtha (n = 5 to 10), Kerosene (n = 10 to 14) and Gas Oil (Diesel) for which n = 14 to 20.

It is evident that if the proportion of CO_2 in the raw feed gas is in the right range, then a syngas could be produced satisfying the requirement that the H_2:CO molar ratio is equal to 2:1.

We estimate the amount of syngas that could theoretically be created from the same raw feed gas rate (781 MMscf/d) and CO_2 content (40 mol%) that we assumed for a benchmark 3 Mt/yr LNG train[6]. We start with reacting the GTL feed CO_2 volume (279 MMscf/d, Table 25) with feed CH_4 in accordance with Equation (3). As shown in Table 26, this creates 1,115 MMscf/d of syngas by consuming the stoichiometric amount of methane (279 MMscf/d).

[6] For a 3.0 Mt/yr LNG train, the product is close to 400 MMscf/d of methane. For 40% CO_2 in raw feed, we assume that the methane required to power CO_2 removal and refrigeration is equivalent to 17% of production.
It can be shown by a material balance calculation that the required raw gas feed rate is 781 MMscf. CO_2 emissions arising from the production process are 7.3 Mt/yr, consisting of 6.0 Mt/yr from CO_2 extraction and 1.3 Mt/yr from fuel combustion. Theoretical CO_2 emissions from LNG combustion are 7.7 Mt/yr, resulting in approximately 15 Mt/yr CO_2 emissions over the production and consumption cycle.

Table 25 – Published pilot plant feed data and scaled-up data

	Pilot plant data for 40% CO_2 in feed gas [35]		Scale up for 3 Mt/yr LNG feed (40% CO_2 in feed gas) Factor = 3.9	
	Nm³/hr	MMscf/d	MMscf/d	kg/hr
Feed CH_4	120,000	107	418	333,533
Feed CO_2	80,000	72	279	611,478
Feedstock	200,000	179	697	945,011
Fuel CH_4	14,520	13	51	40,358
Fuel CO_2	9,680	9	34	73,989
Fuel total	24,200	22	84	114,346
Inlet CH_4	134,520	120	469	373,891
Inlet CO_2	89,680	80	312	685,467
Total inlet	224,200	200	781	1,059,357

Table 26 – Reforming of methane with CO_2

	CH_4	+ CO_2	⇨	$2H_2$	+ 2CO
MMscf/d	279	279		557	557
kmol/hr	13,897	13,897		27,794	27,794
kg/hr	222,356	611,478		55,589	778,244

The remaining amount of CH_4 in the feed available for steam reforming is 139 MMscf/d. This is the GTL inlet CH_4 (418 MMscf/d, Table 25) less the amount already consumed in the reaction described by Equation (3) (279 MMscf/d). This gives an additional theoretical syngas quantity of 557 MMscf/d, as shown in Table 27.

Table 27 – Steam reforming of methane

	CH_4	+ H_2O	⇨	$3H_2$	+ CO
MMscf/d	139	139		418	139
kmol/hr	6,949	6,949		20,846	6,949
kg/hr	111,178	125,075		41,692	194,561

Adding the theoretical amount of syngas from Equation (3)/Table 26 and Equation (4)/

Table 27 gives us 1,672 MMscf/d with a H_2:CO molar ratio of 1.4:1. To increase this ratio to the 2:1 needed for the Fischer-Tropsch reaction, we find that 140 MMscf/d of CO needs to consumed by the water gas shift reaction as shown in

Table 28. The resulting syngas quantity stays the same (1,672 MMscf/d) but it now has the needed H_2:CO ratio of 2:1. The theoretical amount of syngas is 9% more than the scaled-up published data [35] as shown in Table 29.

Table 28 – Water gas shift reaction

	CO	+ H_2O	⇨	H_2	+ CO_2
MMscf/d	140	140		140	140

Table 29 – Published and scaled-up syngas yield by CO_2/steam reforming

	Published data for 40% CO_2 in feed gas [35]			Worked example for 3 Mt/yr LNG plant feed (40% CO_2)			
				Scale up of pilot plant data by factor of 3.9 per Table 25		'Theoretical' syngas (from Table 26, 21 and 22)	
	Nm³/hr	MMscf/d	kg/hr	MMscf/d	kg/hr	MMscf/d	kg/hr
H_2	293 333	262	26 158	1 022	101 913	1,115	111,244
CO	146 667	131	183 108	511	713 391	557	777,323
Total	440 000	393	209 267	1 533	815 304	1,672	888,566

In Table 30 the indicative yield of the GTL process is given both for the published case and the scaled case. Table 31 details the sources and flow-rates of carbon for the GTL process. Finally, Table 32 estimates CO_2 emissions from the GTL process.

Table 30 – Yield of GTL products and associated CO_2 emissions from combustion

Published data for 40% CO_2 in feed [35]		Scaled data for comparison with 3.0 Mt/yr LNG train feed			
		Scaled GTL production (factor = 3.9)	CO_2 emissions factor[7]	Estimated CO_2 emissions from combustion by user	
GTL products	bbl/d	bbl/d	lb CO_2/bbl	lb/d	Mt/yr
Naphtha ($C_5 – C_{10}$)	4,374	17,041	886.0	15,098,087	2.50
Kerosene ($C_{10} – C_{14}$)	6,069	23,645	904.6	21,389,122	3.54
Gas oil ($C_{14} – C_{20}$)	4,557	17,754	940.1	16,690,614	2.76
Total	15,000	58,440		53,177,823	8.80

Table 31 – Estimated mass flow of carbon entering GTL production plant

	GTL plant raw feed scaled up for 3 Mt/yr LNG comparison (40% CO_2 in feed gas) from Table 25		Carbon content of feed gas
	MMscf/d	kg/d	kg/hr
Feed CH_4	418	8,004,665	6,003,499
Feed CO_2	279	14,675,220	4,002,333
Feedstock total	697	22,679,885	10,005,832
Fuel CH_4	51	968,565	726,423
Fuel CO_2	34	1,775,702	484,282
Fuel total	84	2,744,267	1,210,705
Total inlet CH_4	469	8,973,230	6,729,922
Total inlet CO_2	312	16,450,922	4,486,615
Total inlet	781	25,424,152	11,216,537

Table 32 – Inferred CO_2 emissions from GTL process by carbon balance

GTL worked example for comparable 3.0 Mt/yr LNG train(40% CO_2)	Derivation	Units	Value

[7] CO_2 emission factors for the combustion of petroleum fuels are derived from EIA published data, see http://www.eia.doe.gov/oiaf/1605/coefficients.html

Estimated CO_2 emissions from combustion of GTL products(from Table 30)	(A)	Mt/yr	8.80
		kg/d	24,121,055
Carbon content of GTL CO_2 emissions = Carbon content of GTL products	$(B) = (A)\left(\frac{12}{44}\right)$	kg/d	6,578,469
Carbon content of feed gas (Table 31)	(C)	kg/d	11,216,537
Inferred CO_2 emissions from GTL plant	$[(C) - (B)]\left(\frac{44}{12}\right)$	kg/d	17,006,249
		Mt/yr	6.2

We compare the overall system performance of the hypothetical CO_2/steam reforming GTL plant taking the same feed as the example 3.0 Mt/yr LNG train. This comparison shows that the estimated total system CO_2 emissions are the same (15 Mt/yr). This is expected, since all the carbon atoms produced from the reservoir in both cases must end up as CO_2 in the atmosphere, unless the CO_2 is captured and stored.

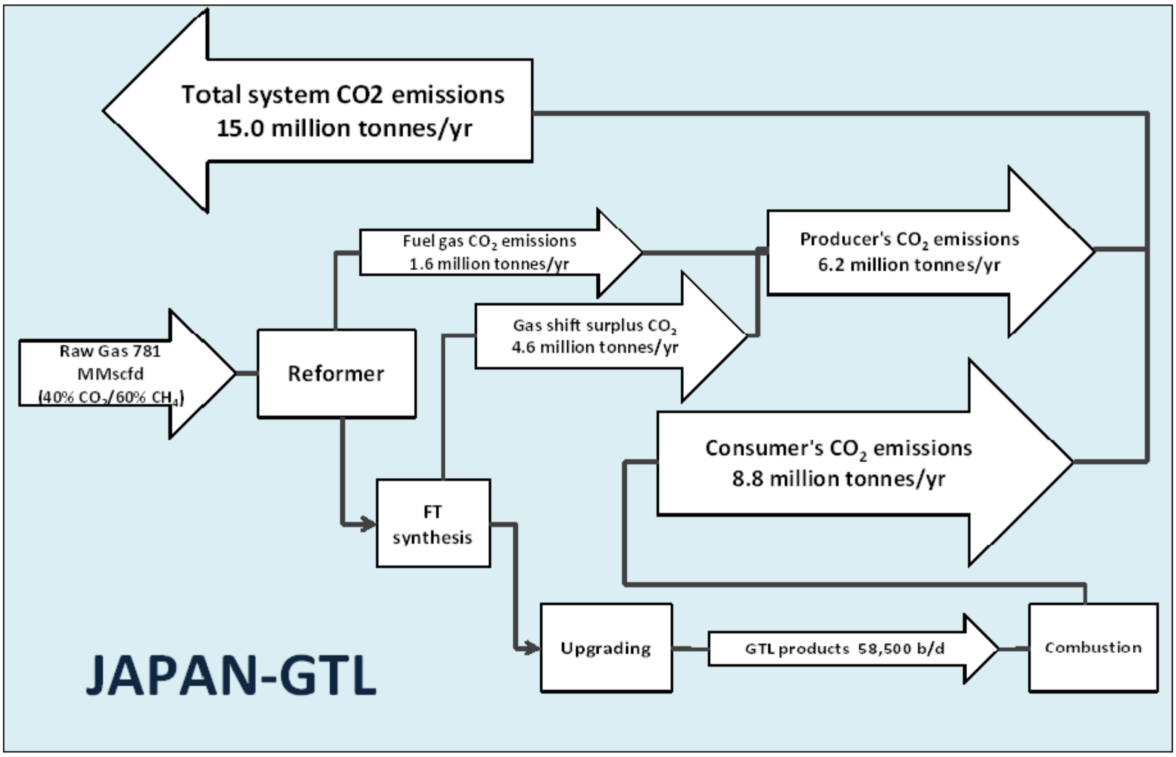

Figure 21 – Hypothetical Japan-GTL® CO_2 emissions

From the discussion above, we conclude that the new GTL process (Figure 21) is expected to produce slightly less plant CO_2 emissions (6.2 Mt/yr) than an equivalent LNG process (7.3 Mt/yr). This is because the new GTL process transfers 66% of the carbon content of the raw feed gas into the product sold to customer. In contrast, the LNG process only passes on 51% of the carbon content in the feed to the customer.

The LNG process requires a capture plant, followed molecular sieves to remove all feed CO_2. This requires significant energy for reboiler heating. The same need to remove all CO_2 applies to conventional GTL processes.

This process produces more energy at higher product value from the same amount of raw high-CO_2 feed gas than does LNG. In addition, compared to LNG, it is easier to transport the GTL products to market.

Appendix 3 Injection site characteristics

Table 33 –Characteristics of the Indonesian formations investigated

Basin		Bintuni B.	E. Natuna B.	N.W. Java B.		North Sumatra B.		Central Sumatra B.		S. Sumatra B.	Kutei B.
Formation		Lower Kembelangan Gp	Terumbu Fm	Batu Raja Fm	Talang Akar Fm	Peutu Fm	Oligocene Sst	Sihapas Gp Sst	Pematang Fm	Talang Akar Fm	Miocene Delta Sst
Areal extent of basin	km²	36,595 (viii)	77,782 (viii)	140,870 [60]	140,870 [60]	258,000 [60]	258,000 [60]	117,300 [60]	117,300 [60]	133,700 [60]	165,000 [60]
Depth base seal	m	3,738 (viii)	2,629 [63] (ix)	2,130 (viii)	2,015 (viii)	2,896 (viii)	2,896 (viii)	600 [66] (ix)	600 [66] (ix)	2,000 (viii)	915 [10] (ix)
Formation thickness	m	50 [61]	800 (viii)	300 (viii)	150 (viii)	152 [65] (ix)	152 [65] (ix)	76 [67] (ix)	76 [67] (ix)	37 [69]	21
Injection depth	m RKB	3,788 (viii)	3,429 (viii)	2,430 (viii)	2,015 (viii)	3,048 [65] (ix)	3,048 [65] (ix)	676 [60]	676 [60]	2,037 (viii)	936 [60]
Porosity	%	12 [62] (ix)	24 (viii)	30 [60]	30 [60]	18 [60]	22 [60]	25% [60]	18% [60]	21.5% (viii)	28 [60]
Permeability	mD	250 [62] (ix)	250 (viii)	1,000 [60]	1,000 [60]	400 (viii)	400 (viii)	1,000 [60]	50 [60]	1,000 (viii)	1,000 [60]
Fm temperature	°C	125 (viii)	171 (viii)	114 [60]	95 [60]	137 [60]	137 [60]	41 [60]	41 [60]	100 [60]	30 [60]
Water depth	m	52 (viii)	145 [5]	0	0	0	109 (viii)	0	0	0	0
Formation pressure at injection depth	MPa	38 (viii)	39 (viii)	24 (viii)	20 (viii)	30 (viii)	30 (viii)	6.4 [68]	6.4 [68]	20 (viii)	9 (viii)
Fracture gradient	MPa/km	16 (viii)	16 (viii)	16 (viii)	16 (viii)	30 (viii)	30 (viii)	16 (viii)	16 (viii)	16 (viii)	16 (viii)
Fracture pressure at injection depth	MPa	61 (viii)	55 (viii)	39 (viii)	32 (viii)	49 (viii)	49 (viii)	11 [60]	11 [60]	32.6 (viii)	15 (viii)

(viii) Calculated or assumed
(ix) Data for oil and gas reservoirs

Table 34 –Characteristics of the Malaysian, Vietnamese, Thai and Bruneian formations investigated

Economy		Malaysia							Thailand	Brunei
			Vietnam							
Basin		Malay Basin						Nam Con Son Basin	Gulf of Thailand B.	Baram Delta B.
Formation		D, E, F & G Groups	H Group	K Group	I Group	J Group	L Group	Nam Con Son Fm	Pattani Trough	Cycle V
Areal extent of basin	km²	83,000 [60]						162,254 (viii)	112,680 [60]	49,000 (viii)
Depth base seal	m	1,300 (viii)	1,600 (viii)	2,850 (viii)	2,400 (viii)	2,150 (viii)	3,300 (viii)	2,972 (viii)	1,220 (viii)	1,950 (viii)
Formation thickness	m	300 (viii)	200 (viii)	50 (viii)	300 (viii)	300 [60]	50 (viii)	423 (viii)	1,650 (x)	50 [70] (xi)
Injection depth	m RKB	1,600 (x)	1,800 (x)	2,900 (x)	2,700 (x)	2,450 (x)	3,350 (x)	3,395 (x)	2,870 (x)	2,000 (x)
Porosity	%	25 [60]	30 [60]	20 [60]	28 [60]	20 [60]	20 [60]	20 (viii)	21 (viii)	20 (viii)
Permeability	mD	100 [60]	800 [60]	400 [60]	100 [60]	100 [60]	400 [60]	150 (viii)	500 (viii)	980 (viii)
Fm temperature	°C	67 [60]	90 [60]	145 [60]	135 [60]	123 [60]	168 [60]	135 (viii)	144 [60]	56 (viii)
Water depth	m	71 (viii)	54 (viii)	57 (viii)	55 (viii)	53 (viii)	57 (viii)	138 (viii)	64 [71]	46 [72] (xi)
Formation pressure at injection depth	MPa	16 (x)	18 (x)	29 (x)	27 (x)	24.5 (x)	34 (x)	34 (x)	29 (x)	20 (x)
Fracture gradient	MPa/km	16 (x)	16 (x)	16 (x)	16 (x)	16 (x)	16 (x)	54 (x)	46 (x)	32 (x)
Fracture pressure at injection depth	MPa	26 (x)	29 (x)	46 (x)	43 (x)	39 (x)	54 (x)	16 (x)	16 (x)	16 (x)

(x) Calculated or assumed
(xi) Data for oil and gas reservoirs

Appendix 4 Results of representative analyses

Table 35 – Detailed engineering results for the representative base cases in Indonesian formations

Economy	Units	Indonesia									
Basin		Bintuni B.	E. Natuna B.	N.W. Java B.		N. Sumatra B.		C. Sumatra B.		S. Sumatra B.	Kutei B.
Formation		Lower Kembelangan Gp	Terumbu Fm	Batu Raja Fm	Talang Akar Fm	Oligocene Sst	Peutu Fm	Sihapas Gp Sst	Pematang Fm	Talang Akar Fm	Miocene Delta Sst
Nominal CO_2 injection rate	Mt/yr	2.9	205.7	0.4	0.3	7.1	1.9	0.3	0.3	0.5	1.7
Annual CO_2-e flows											
Injected	Mt/yr	2.9	205.7	0.4	0.3	7.1	1.9	0.3	0.3	0.5	1.7
Avoided	Mt/yr	2.9	203.8	0.4	0.3	7.0	1.9	0.3	0.3	0.5	1.6
Total CO_2-e flows											
Injected	Mt	58.0	4,113.2	8.8	6.6	141.4	37.5	6.0	6.6	9.7	33.0
Avoided	Mt	57.8	4,076.4	8.7	6.5	140.7	37.3	6.0	6.6	9.6	32.9
Present Value of CO_2-e flows											
Injected	Mt	25.1	1,778.5	3.8	2.8	61.2	16.2	2.6	2.9	4.2	14.3
Avoided	Mt	25.0	1,762.6	3.8	2.8	60.9	16.1	2.6	2.8	4.2	14.2
Transport design											
Pipeline length	km	10	10	10	10	10	10	10	10	10	10
Nominal pipeline diameter	mm	150	950	100	100	300	150	100	100	100	100
Transport compr. duty	MW	2	529	1	1	11	3	0.3	0.3	1	2
Transport compr. pressure rise	MPa	15	14	11	10	15	15	4	5	9	14
Formation properties											
Injection depth	m	3,788	3,429	2,430	2,165	3,048	3,048	676	676	2,037	936
Effective permeability	mD	250	250	1,000	1,000	400	400	1,000	50	1,000	1,000
Formation thickness	m	50	800	300	150	305	152	76	76	37	21
Formation temperature	°C	125	144	114	102	137	137	41	41	100	30
Formation pressure	MPa	38	34	24	22	30	30	6	6	20	9
Fracture pressure	MPa	61	55	39	35	49	49	11	11	33	15
Injection design											
Platform		Steel jacket	Steel jacket	No platform	No platform	Steel Jacket	No Platform	No platform	No platform	No platform	No platform
Well type		Deviated	Deviated	Deviated	Deviated	Deviated	Deviated	Deviated	Deviated	Deviated	Deviated
Well head compr. required		No	Yes	No	No	No	No	No	No	No	No
Well head compr. duty	MW	n/a	57	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Well head compr. pressure rise	MPa	n/a	8	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Number of wells		4	81	3	3	3	3	4	12	4	9
Total extra power required	MW	2	586	1	1	11	3	0.3	0.3	1	2

Table 36 – Detailed economic results for the representative base cases in Indonesian formations

Economy	Units	Indonesia									
Basin		Bintuni B.	E. Natuna B.	N.W. Java B.		N. Sumatra B.		C. Sumatra B.		S. Sumatra B.	Kutei B.
Formation		Lower Kembelangan Gp	Terumbu Fm	Batu Raja Fm	Talang Akar Fm	Peutu Fm	Oligocene Sst	Sihapas Gp Sst	Pematang Fm	Talang Akar Fm	Miocene Delta Sst
Nominal CO_2 injection rate	Mt/yr	2.9	205.7	0.4	0.3	7.1	1.9	0.3	0.3	0.5	1.7
Total capital costs											
All power plants	US$ million	2	231	1	1	8	3	0.4	0.4	1	2
Source compr. machine	US$ million	28	1,999	15	15	79	43	11	11	15	28
Source compr. platform	US$ million	61	61	n/a	n/a	61	n/a	n/a	n/a	n/a	n/a
Well-head compr. machine	US$ million	n/a	136	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Well-head compr. platform	US$ million	n/a	37	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transport pipeline	US$ million	45	65	2	2	49	3	2	2	2	2
Inter-platform pipeline	US$ million	n/a	381	9	9	n/a	17	10	22	11	22
Injection wells	US$ million	40	810	30	30	30	30	40	120	40	90
Injection platform	US$ million	31	426	n/a	n/a	24	n/a	n/a	n/a	n/a	n/a
On costs	US$ million	37	734	10	10	44	17	11	27	12	25
Total Cost	US$ million	244	4,880	67	66	295	112	75	183	81	169
Annual operating costs	US$ million/yr	6	246	2	2	10	3	1	3	2	4
Total decommissioning costs	US$ million	60	1,152	16	16	72	27	19	46	20	42
Present value of all costs											
All power plants	US$ million	6	1,305	3	3	29	9	1	1	2	7
Source compr. machine	US$ million	34	2,468	19	19	98	53	14	14	19	34
Source compr. platform	US$ million	76	76	n/a	n/a	76	n/a	n/a	n/a	n/a	n/a
Well-head compr. machine	US$ million	n/a	167	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Well-head compr. platform	US$ million	n/a	46	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transport pipeline	US$ million	44	64	2	2	47	2	2	2	2	2
Inter-platform pipeline	US$ million	n/a	371	8	8	0	17	10	21	11	21
Injection wells	US$ million	42	860	32	32	32	32	42	127	42	96
Injection platform	US$ million	33	453	n/a	n/a	25	n/a	n/a	n/a	n/a	n/a
On costs	US$ million	33	650	9	9	39	15	10	24	11	23
Total Cost	US$ million	268	6,459	73	72	347	128	79	190	86	182
Specific cost of CO_2-e avoided											
All power plants	US$/t	0.2	0.7	0.8	0.9	0.5	0.6	0.4	0.4	0.5	0.5
Source compr. machine	US$/t	1.4	1.4	4.9	6.6	1.6	3.3	5.3	4.8	4.5	2.4
Source compr. platform	US$/t	3.0	0.04	n/a	n/a	1.2	n/a	n/a	n/a	n/a	n/a
Well-head compr. machine	US$/t	n/a	0.1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Well-head compr. platform	US$/t	n/a	0.03	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transport pipeline	US$/t	1.8	0.04	0.5	0.6	0.8	0.2	0.7	0.6	0.4	0.1
Inter-platform pipeline	US$/t	n/a	0.2	2.3	3.0	n/a	1.0	3.9	7.5	2.6	1.5
Injection wells	US$/t	1.7	0.5	8.5	11.3	0.5	2.0	16.4	44.8	10.2	6.7
Injection platform	US$/t	1.3	0.3	n/a	n/a	0.4	n/a	n/a	n/a	n/a	n/a
On costs	US$/t	1.3	0.4	2.4	3.1	0.6	0.9	3.9	8.6	2.6	1.6
Total Cost	US$/t	10.7	3.7	19.3	25.5	5.7	8.0	30.5	66.6	20.8	12.8

Table 37 – Detailed engineering results for the representative base cases in Malaysian, Vietnamese, Thai and Bruneian formations

Economy	Units	Malaysia							Thailand	Brunei	
				Vietnam							
Basin		Malay B.							Nam Con Son B.	G. of Thailand B.	Baram Delta B.
Formation		D Group	E Group	H Group	K Group	J Group	I Group	L Group	Nam Con Son Fm	Pattani Trough	Cycle V
Nominal CO_2 injection rate	Mt/yr	1.1	4.0	1.3	1.2	1.3	1.3	1.2	2.6	3.5	27.4
Annual CO_2-e flows											
Injected	Mt/yr	1.1	4.0	1.3	1.2	1.3	1.3	1.2	2.6	3.5	27.4
Avoided	Mt/yr	1.1	4.0	1.3	1.2	1.3	1.3	1.2	2.6	3.5	27.3
Total CO_2-e flows											
Injected	Mt	22.6	80.6	26.3	23.4	26.3	26.3	23.4	51.7	69.8	548.9
Avoided	Mt	22.5	80.3	26.1	23.3	26.1	26.1	23.3	51.7	69.6	545.2
Present Value of CO_2-e flows											
Injected	Mt	9.8	34.8	11.4	10.1	11.4	11.4	10.1	22.4	30.2	237.4
Avoided	Mt	9.7	34.7	11.3	10.1	11.3	11.3	10.1	22.4	30.1	235.7
Transport design											
Pipeline length	km	10	10	10	10	10	10	10	10	10	10
Nominal pipeline diameter	mm	150	150	200	150	150	150	200	100	250	850
Transport compr. duty	MW	2	4	3	3	3	3	3	0.3	3	59
Transport compr. pressure rise	MPa	7	15	8	15	15	14	15	12	15	6
Formation properties											
Injection depth	m	1,600	1,600	1,800	2,900	2,700	2,450	3,350	3,395	2,870	2,000
Effective permeability	mD	100	100	800	400	100	100	400	150	500	980
Formation thickness	m	300	300	200	50	300	300	50	423	1,650	50
Formation temperature	°C	67	67	90	145	135	123	168	135	144	56
Formation pressure	MPa	16	16	18	29	27	24	33	34	29	20
Fracture pressure	MPa	26	26	29	46	43	39	54	54	46	32
Injection design											
Platform		Steel jacket	Steel jacket	Steel jacket	Steel jacket	Steel jacket	Steel jacket	Steel jacket	Steel jacket	Steel jacket	Steel jacket
Well type		Deviated	Deviated	Deviated	Deviated	Deviated	Deviated	Deviated	Deviated	Deviated	Deviated
Well head compr. required		No	No	No	No	No	No	No	No	No	No
Well head compr. duty	MW	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Well head compr. pressure rise	MPa	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Number of wells		4	8	3	4	4	4	4	3	3	36
Total extra power required	MW	2	4	3	3	3	3	3	0.3	3	59

Table 38 – Detailed economic results for the representative base cases in Malaysian, Vietnamese, Thai and Bruneian formations

Economy		**Malaysia**								**Thailand**	**Brunei**
				Vietnam							
Basin	–	Malay B.							Nam Con Son B.	G. of Thailand B.	Baram Delta B.
Formation	–	D Group	E Group	H Group	K Group	J Group	I Group	L Group	Nam Con Son Fm	Pattani Trough	Cycle V
Nominal CO_2 injection rate	Mt/yr	1.1	4.0	1.3	1.2	1.3	1.3	1.2	2.6	3.5	27.4
Total capital costs											
All power plants	US$ million	2	3	2	2	2	3	2	0.4	3	31
Source compr. machine	US$ million	21	44	28	28	28	28	28	8	43	318
Source compr. platform	US$ million	61	61	61	61	61	61	61	61	61	61
Well-head compr. machine	US$ million	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Well-head compr. platform	US$ million	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transport pipeline	US$ million	45	45	46	45	45	45	46	44	48	62
Inter-platform pipeline	US$ million	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Injection wells	US$ million	40	80	30	40	40	40	40	30	30	360
Injection platform	US$ million	31	51	24	31	31	31	31	24	24	182
On costs	US$ million	35	50	34	37	37	37	37	30	37	180
Total Cost	US$ million	236	336	226	244	244	245	245	198	245	1,195
Annual operating costs	US$ million/yr	6	8	6	6	6	6	6	4	7	40
Total decommissioning costs	US$ million	59	83	56	60	60	60	61	49	61	289
Present value of all costs											
All power plants	US$ million	5	12	8	7	7	9	7	1	9	141
Source compr. machine	US$ million	26	54	34	34	34	34	34	10	53	392
Source compr. platform	US$ million	76	76	76	76	76	76	76	76	76	76
Well-head compr. machine	US$ million	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Well-head compr. platform	US$ million	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transport pipeline	US$ million	44	44	45	44	44	44	45	43	46	61
Inter-platform pipeline	US$ million	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Injection wells	US$ million	42	85	32	42	42	42	42	32	32	382
Injection platform	US$ million	33	54	25	33	33	33	33	25	25	193
On costs	US$ million	32	45	30	33	33	33	33	26	33	159
Total Cost	US$ million	258	370	250	269	269	271	270	214	274	1,405
Specific cost of CO_2-e avoided											
All power plants	US$/t	0.5	0.3	0.7	0.7	0.6	0.8	0.7	0.05	0.3	0.6
Source compr. machine	US$/t	2.7	1.6	3.1	3.4	3.1	3.1	3.4	0.5	1.8	1.7
Source compr. platform	US$/t	7.8	2.2	6.7	7.5	6.7	6.7	7.5	3.4	2.5	0.3
Well-head compr. machine	US$/t	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Well-head compr. platform	US$/t	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transport pipeline	US$/t	4.5	1.3	4.0	4.4	3.9	3.9	4.5	1.9	1.5	0.3
Inter-platform pipeline	US$/t	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Injection wells	US$/t	4.4	2.4	2.8	4.2	3.8	3.8	4.2	1.4	1.1	1.6
Injection platform	US$/t	3.3	1.6	2.2	3.2	2.9	2.9	3.2	1.1	0.8	0.8
On costs	US$/t	3.2	1.3	2.7	3.2	2.9	2.9	3.3	1.2	1.1	0.7
Total Cost	US$/t	26.5	10.7	22.2	26.7	23.9	24.0	26.9	9.6	9.1	6.0

Appendix 5 Fiscal terms in South-East Asia

This section gives a description of the fiscal terms which are believed to be typical of current agreements in the five counties in South-East Asia. Depending on how governments deal with the effect of CO_2 transport and storage on these terms, they can have a significant effect on the economics of CCS in the region. The analyses of these effects are shown in the body of this report.

A5.1 Indonesian PSC

Oil and gas production activities in Indonesia are currently governed by the terms of Production Sharing Contracts (PSC). This section summarises the terms that we assume will apply to the representative analyses for Indonesia and the Natuna development case study analysed in the main body of this report. However, the actual terms that apply to any development are confidential and might differ from those set out here.

The key components of Indonesian PSC for oil and natural gas development include First Tranche Petroleum (FTP), Cost Recovery, Profit Sharing, Income Tax and Domestic Market Obligation (DMO).

FTP

The first claim on Gross Revenue from the sales of petroleum is FTP which is shared between the State and the contractors. FTP is currently 20% of the gross revenue in conventional areas. Shares of FPT are in principle negotiable, but are typically the same as the shares for Profit Petroleum (see below).

Cost Recovery

After FTP, the contractors are allowed to recover their costs from the remaining revenue. There is no cost recovery ceiling in Indonesian PSCs. The contractors can recover costs from 100% of the remaining revenue after the share of FTP.

Profit Sharing

The revenue remaining after FTP and Cost Recovery is Profit Petroleum which is shared between the State and the contractors. The shares vary depending on the location and the type of the development. Since the introduction of the 1993 incentives, the contractors' share of profit oil is 15% for conventional areas. The contractors' share of profit gas is 35% for conventional areas.

The profit shares given above are on an after-tax basis. However, the shares are expressed in contracts on a before-tax basis. The equivalent before-tax share is derived by dividing the given after-tax share by (1 – tax rate). Therefore, providing the current income tax rate of 44%, the before-tax shares are as follows.

Table 39 – Profit sharing on a before-tax basis in Indonesian PSC

	Conventional areas	Frontier areas
Oil	26.79%	62.50%
Gas	62.50%	71.43%

Income Tax

The current income tax rate is 44%. There is a ring fence around the contract area for income tax purposes. The income tax applying to the contracts signed between 1984 and 1994 was 48%.

Domestic Market Obligation (DMO)

Under Indonesian PSCs, in each year after the fifth year of production, contractors must sell a portion of their FTP and Profit Oil to the domestic Indonesian market at a discounted price. The DMO oil price is 15% of the price obtained in international markets for conventional contracts. Under the 2002 conventional model contract, DMO applies to natural gas as well, but the DMO gas price is at market rates.

A5.2 Malaysian PSC

Oil and gas production activities in Malaysia are currently governed by the terms of Production Sharing Contracts (PSC). In 1997, Petronas introduced a new PSC based on the “revenue over cost” concept (the "R/C" PSC) to encourage additional investment in Malaysia’s upstream sector.

The key components of Malaysian PSC for oil and natural gas developments include Royalty, Cost Recovery, Profit Sharing and Income Tax.

Royalty

Royalty is set at a maximum of 10% of gross revenue and is payable in kind.

Supplementary payment

The supplementary payment is a cash payment to Petronas. It is payable in any month when the price of crude oil or natural gas exceeds a real base price of US$25/bbl or US$1.8/MMBtu and the Contractors’ R/C exceeds one. Under these situations, the Contractors must pay to Petronas 70% of their Profit Oil or Profit Gas. The real base price increases at 4% per year from the effective date of the contract.

Cost recovery

Costs are recovered quarterly from a percentage of gross production. Since the introduction of the 1997 model contract, the cost recovery ceiling has been in the range of 30% to 70% depending on the profitability of the contract area as measured by the ratio of the contractor’s revenue to the contractor’s costs (the R/C ratio).

The Contractors' R/C ratio is defined as follows:

Revenue(R) = Contractors' Cumulative Value of Cost Gas and Profit Gas less a Supplementary Payment

Cost(C) = Contractors' Cumulative Petroleum Costs less Non Recoverable Expenditure & Disputed Costs.

Excess Cost Recovery is considered to be Profit Gas and is shared between the state and the Contractor on a sliding scale.

Profit Sharing

Profit remaining after Royalty and Cost Recovery is then shared between Petronas and the Contractor on a sliding scale based on the Contractor’s R/C ratio and the cumulative production level of the contract area or the Threshold Volume (THV). For gas field, the THV is 0.75 Tcf or accumulative production per discovery whichever is smaller. Table 40 below summarises the Cost Recovery Ceiling and the Profit Shares.

Table 40 – Cost Recovery Ceiling and Profit Sharing in Malaysia PSC

Contractor's R/C ratio	Cost Recovery Ceiling	Contractor's share of Excess Cost Recovery		Contractor's share of Profit Gas	
		Below THV	Above THV	Below THV	Above THV
0.0 to 1.0	70%	-	-	80%	40%
1.0 to 1.4	60%	80%	40%	70%	30%
1.4 to 2.0	50%	70%	40%	60%	30%
2.0 to 2.5	30%	60%	40%	50%	30%
2.5 to 3.0	30%	50%	40%	40%	30%
> 3.0	30%	40%	20%	30%	10%

Income Tax

Income Tax is levied at 38% on the Contractors’ share of cost and Profit Gas.

A5.3 Vietnamese PSC

Oil and gas production activities in Vietnam are currently governed by the terms of Production Sharing Contracts (PSC). The key components of Vietnamese PSC for oil and natural gas development include Royalties, Cost Recovery, Profit Sharing, Withholding Tax, Export Duty and Income Tax.

Royalty

Royalty is levied as a percentage of Gross Revenue. It is calculated on an incremental sliding scale based on the rate of production. Before 1 July 2000, the minimum and maximum royalty rates are 6% and 25% for crude oil and 0% and 10% for gas. The sliding scale of royalties is shown in Table 41.

Table 41 – Royalty rates in Vietnamese PSC

Average daily production		Royalty rate
Oil (Mbbl/d)	Gas (MMscf/d)	
0 – 20	-	8%
20 – 50		8%
50 – 75		10%
75 – 100		15%
100 – 150		20%
over 150		25%
-	0 – 175	0%
	175 – 350	5%
	over 350	10%

Cost Recovery

After Royalty, the contractors are allowed to recover costs from the Gross Revenue, subject to a negotiated cost recovery ceiling. In the 1990s, the ceilings were in the range of 30% to 45%. Costs can be recovered under Vietnamese PSCs include all exploration, appraisal, development and production costs incurred within the contract area. All costs are expensed and recovered immediately.

Profit Sharing

The revenue remaining after royalty and cost recovery is Profit Petroleum which is shared between the contractors and the State at negotiable rates on an incremental sliding scale depending on the production rate. Table 42 gives the indicative profit shares for crude oil.

For profit gas, the contractors' share is indicatively a fixed 50%.

Export Duty

There is an export duty at the rate of 4% of the market price of the cost recovery oil and profit oil exported outside Vietnam. The rate is 0% for exported natural gas.

Table 42 – Profit Sharing in Vietnamese PSC

Increment of Production (Mbbl/d)	Contractors' share of Profit Petroleum
0 – 75	50%
75 – 100	45%
100 – 150	40% – 45%
over 150	30% – 40%

Withholding Tax

Withholding tax is 3%, 5% or 7% of the profit transferred, depending on the level of capital contribution of such foreign investor.

Income Tax

The income tax rate set out in the 1993 Petroleum Law is 50%. However, income tax might be exempt or reduced for special cases. At the discretion of the government, the contractors can be exempt from paying income tax for a maximum of two years.

A5.4 Thailand III fiscal regime

Oil and gas production activities in Thailand are currently governed by the terms in the Thailand III fiscal regime. The next section contains an account of the fiscal terms for the Thailand I fiscal regime, under which many existing gas developments operate.

The key components of Thailand III fiscal regime for oil and natural gas development include Royalty, Special Remuneratory Benefit (SRB) and Income Tax.

Royalty

Royalty is payable monthly out of Gross Revenue on a sliding scale depending on production rates. The incremental sliding scale is shown in Table 43 below.

Table 43 – Royalty rates in Thailand fiscal regime

Oil production (Mbbl/d)	Gas production (MMscf/d)	Royalty rate shallow water areas (<200m)
0 – 2	0 – 20	5.00%
2 – 5	20 – 50	6.25%
5 – 10	50 – 100	10.00%
10 – 20	100 – 200	12.50%
over 20	over 200	15.00%

Special Remuneratory Benefit (SRB)

SRB is payable on Profit Petroleum once all prior losses are offset. The SRB payment equals the profit petroleum multiplied by the SRB rate. The steps of the derivation of Profit Petroleum and SRB rate are illustrated as follows.

Profit Petroleum

The profit petroleum is calculated by deducting the following from the gross revenue: capital costs, operating costs, royalty payments, any losses carried forward and a special reduction, if any. The special reduction is defined as the "amount of money the government prescribes from time to time when awarding concessions". The special reduction rate for Gulf of Thailand is 25%.

SRB rate

The SRB rate payable depends on the "annual revenue per one metre depth of well" (in Baht per metres). It also takes into account the geology and geological risk which is reflected by a geological stability factor (GSF). The annual revenue used in the calculation is adjusted by an inflation factor and a currency exchange factor. The annual revenue per one metre depth of well is calculated using the equation below.

$$Annual\ revenue\ per\ one\ metre\ depth\ of\ well = \frac{Rev_e}{M+GSF} \quad (7)$$

Where –

Rev_e (Baht) = adjusted annual revenue that reflects the dollar value of any year's annual revenue at the time the concession was granted.

M (metres) = cumulative metres of wells drilled on the concession area. This includes dry holes, as well as water and gas injection wells, but excludes abandoned production wells which have produced over 100,000 barrels of oil.

GSF (metres) = geological stability factor. GSF is 600,000 for Gulf of Thailand.

Rev_e is calculated as follows –

$$Rev_e = \frac{Rev_m}{2}\left(\frac{I_e}{I_m}\right)\left(\left(\frac{C_e}{C_m}\right)+\left(\frac{P_e}{P_m}\right)\right) \quad (8)$$

Where –

Rev_m	=	current year's revenue in Baht
I_e	=	the exchange rate in the year the concession was awarded
I_m	=	the exchange rate in the accounting (i.e. current) period
C_e	=	the consumer price index in the year the concession was awarded
I_m	=	the consumer price index in the accounting (i.e. current) period
P_e	=	the producer price index* in the year the concession was awarded
P_m	=	the producer price index* in the accounting (i.e. current) period

Once the annual revenue per metre is derived, the SRB rate can be looked up in Table 44. The SRB rate is calculated every year and is rounded up to the nearest percent. Once the profit petroleum and the SRB rate are known, the SRB payment can be calculated.

Table 44 – SRB rates in Thailand fiscal regime

Annual revenue per one metre depth of well (Baht/metre)	SRB rate
below 4,800	0%
4,800 – 14,400	0% plus 1% per 240 Baht/metre
14,400 – 33,600	40% plus 1% per 960 Baht/metre
33,600 – 91,200	60% plus 1% per 3,840 Baht/metre
above 91,200	75%

Income Tax

The current income tax rate is 50%.

A5.5 Thailand I fiscal regime

Oil and gas production activities in Thailand are currently governed by the terms in the Thailand III fiscal regime. However, many existing gas developments operate under Thailand I fiscal terms. The Thailand I regime is described in the following:

1. A royalty of 12.5% of gross revenue
2. Income tax at 50% of taxable income

A5.6 Brunei PSC

Oil and gas production activities in Brunei are currently governed by the terms of Production Sharing Contracts (PSC).

The key components of Brunei fiscal regime for oil and natural gas development include Royalty, Cost Recovery, Profit Sharing and Income Tax. These are described below.

Royalty

In the 2000 model agreement, for onshore fields, the royalty rate is 12.5% and for deepwater developments, the royalty rate is 8%.

Under concessions awarded before the 2001 bidding round, the royalty rates depend on the location of the developments. The rate is 12.5% for onshore fields, 10% for discoveries between three and ten nautical miles offshore and 8% for discoveries more than ten nautical miles offshore.

Cost Recovery

After Royalty, the contractors are allowed to recover costs from the Gross Revenue, subjected to a negotiated cost recovery ceiling. The cost recovery ceilings announced in the government's bid presentation on 23 October 2000 are 60% for oil discoveries and 70% for gas discoveries onshore and 80% for oil discoveries and gas discoveries in deepwater. Costs can be recovered under the Brunei PSCs include exploration and appraisal costs, development costs, operating costs, abandonment sinking fund and excess revenue payments. All costs are expensed and recovered immediately. Unrecovered costs are carried forward indefinitely until fully recovered but not beyond the duration of the contract.

Profit Sharing

The revenue remaining after Royalty and Cost Recovery is Profit Petroleum which is shared between the contractors and the State at negotiable rates on an incremental sliding scale depending on the production rate. The profit shares indicated in the government's bid presentation of 23 October 2000 are given in Table 45 and Table 46.

Table 45 – Profit Sharing in Brunei Onshore PSCs

Production		Contractors' Profit Share
Oil	Gas (Tcf)	
0 – 10 Mbbl/d 10 – 25 Mbbl/d > 25 Mbbl/d > 50 MMbbl cumulative production	–	50% 40% 30% 50%
–	0 – 2 > 2	50% 40%

Table 46 – Profit Sharing in Brunei Offshore PSCs

Production		Contractors' Profit Share
Oil	Gas (Tcf)	
0 – 50 Mbbl/d 50 – 100 Mbbl/d > 100 Mbbl/d > 200 MMbbl cumulative production	–	75% 65% 60% 50%
–	0 – 4 > 4	60% 30%

Income Tax

The petroleum income tax rate in Brunei is 55%.

The deductions for income tax include exploration costs, operating costs, royalty and depreciation. Exploration costs and operating costs are immediately deductible. Capital costs are depreciated on a straight line basis over different periods of time depending on the category of expenditure.