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PRE-FEASIBILITY STUDY OF CARBON CAPTURE AND STORAGE (CCS) TECHNOLOGIES: A CASE STUDY OF OFFSHORE NATURAL GAS FIELD IN THAILAND

Mr. Monsan Kantham

A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
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มนต์สันต์ กัณธรรม : การศึกษาความเป็นไปได้เบื้องต้นในการใช้ประโยชน์ เทคโนโลยีการดัก จับและกักเก็บคาร์บอน: กรณีศึกษาของแหล่งก๊าซธรรมชาตินอกชายฝั่งในประเทศไทย (PRE-FEASIBILITY STUDY OF CARBON CAPTURE AND STORAGE (CCS) TECHNOLOGIES: A CASE STUDY OF OFFSHORE NATURAL GAS FIELD IN THAILAND) อ. ที่ปรึกษา วิทยานิพนธ์หลัก: อ. ดร. ฐิติศักดิ์ บุญปราโมทย์, 92 หน้า.

เทคโนโลยีการดัก จับและกักเก็บคาร์บอน (Carbon Capture and Storage "CCS") ได้เข้ามามีบทบาทในการช่วยลดปริมาณการปลดปล่อยก๊าซเรือนกระจกสู่บรรยากาศ ในขณะที่พิธีสารเกียวโตพยายามที่จะบรรลุการปกป้องสภาพภูมิอากาศโลกและลดต้นทุนในกระบวนการลดการปลดปล่อยก๊าซเรือนกระจก โดยนำเสนอนวัตกรรม กลไกความร่วมมือในการปกป้องสภาพภูมิอากาศระหว่างอุตสาหกรรมและประเทศกำลังพัฒนา เรียกว่า กลไกการพัฒนาที่สะอาด (Clean Development Mechanism) ซึ่งในการศึกษานี้ได้มีการนำประเด็นความเป็นไปได้ในการนำก๊าซเรือนกระจกที่ถูกดักจับด้วยเทคโนโลยีการดัก จับและกักเก็บคาร์บอนใน มาใช้กับกลไกการพัฒนาที่สะอาด

พื้นที่ศึกษาตัวอย่างนี้ผลิตก๊าซธรรมชาติประมาณ 350 ล้านลูกบาศฟุตต่อวัน ซึ่งประกอบด้วยก๊าซคาร์บอนไดออกไซด์ร้อยละ 28-32 ซึ่งนำไปเผาทิ้งทุกวัน วัตถุประสงค์หลักคือเพื่อศึกษาภาพรวมของเทคโนโลยีการดักจับและกักเก็บคาร์บอนใต้แหล่งผลิตก๊าซธรรมชาติ ซึ่งมีการวิเคราะห์ความที่เหมาะสมกับแหล่งก๊าซธรรมชาตินอกชายฝั่งและเพื่อประเมินความเป็นไปได้ทางด้านเศรษฐกิจของเทคโนโลยีการดักจับและกักเก็บคาร์บอน ในแง่ของโครงการกลไกการพัฒนาที่สะอาด นอกจากนี้การวิเคราะห์ในด้านเศรษฐกิจในการศึกษานี้ได้ดำเนินการประเมินผลโดยอาศัยเครื่องมือการจำลองแบบสโตแคสติกส์ เราสามารถตรวจสอบการกระจายของมูลค่าปัจจุบัน (Net Present Value) จากตัวแปรที่มีผลต่อประสิทธิภาพของโครงการโดยใช้วิธีการจำลองแบบมอนติคาร์โล (Monte Carlo Simulation) มาจัดการกับความไม่แน่นอนในแง่ของค่าใช้จ่ายการสร้าง ค่าดำเนินงานทั้งโครงการและราคาของคาร์บอนเครดิต

จากการศึกษาพบว่าเทคโนโลยีการดัก จับและกักเก็บคาร์บอน สามารถลดการปลดปล่อยคาร์บอนสู่ชั้นบรรยากาศประมาณ 850,000 ตันต่อปี การรวมเทคโนโลยีการดัก จับและกักเก็บคาร์บอนกลไกการพัฒนาที่สะอาดช่วยให้เกิดแรงจูงใจที่จะลงทุนเพิ่มขึ้นเพราะเป็นการช่วยลดค่าใช้จ่ายในการลงทุนของเทคโนโลยีการดัก จับและกักเก็บคาร์บอน อย่างไรก็ตาม โครงการไม่สามารถพัฒนาเทคโนโลยีการดัก จับและกักเก็บคาร์บอนหากไม่มีการสนับสนุนทางด้านคาร์บอนเครดิต แม้กระนั้นราคาของคาร์บอนเครดิตในปัจจุบันก็ไม่สามารถชักนำให้มีการลงทุนในด้านเทคโนโลยีการดัก จับและกักเก็บคาร์บอน

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม .... ลายมือชื่อนิสิต ....

สาขาวิชา วิศวกรรมปิโตรเลียม .... ลายมือชื่ออ. ที่ปรึกษา วิทยานิพนธ์หลัก ....

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MONSAN KANTHAM. PRE-FEASIBILITY STUDY OF CARBON CAPTURE AND STORAGE (CCS) TECHNOLOGIES: A CASE STUDY OF OFFSHORE NATURAL GAS FIELD IN THAILAND. ADVISOR: THITISAK BOONPRAMOTE, Ph.D., 92 pp.

Carbon dioxide capture and storage (CCS) has played more roles in greenhouse gas (GHG) reduction while the Kyoto Protocol sets targets for each nation to reduce its emission of CO_2 and reduce investment cost of reduction between developed country and developing country by using Clean Development Mechanism (CDM). In this study, CCS systems are specifically designed to remove CO_2 from the natural gas production and safely store the CO_2 in deplete gas reservoir. Inclusion of CCS in the CDM could be a way to provide an incentive to those CCS project types that are ready to be deployed commercially.

A case study on natural gas field produces natural gas approximately 350 MMSCF per day which contains 28-32 percent of CO_2. In order to meet sale specification, company has to reduce CO_2 to 23 percent before delivery. The process leads to emit great amount of CO_2 annually so the technical and economic feasibility of CCS is being studied. An efficient model was developed to predict the economics involved in the CCS projects. The model mainly consists of Discounted Cash Flow Analysis and Monte Carlo Simulation to determine uncertainties of the project which is composed of capital cost of construction, operating cost and carbon credits.

From the study, the CCS project able to achieve significant reduction in GHG emissions approximately 850,000 tons per year. Inclusion of CCS project in the CDM can provide an important incentive for potential investment in the project. This incentive could offset the incremental cost of the technology however the project itself cannot achieve in CCS technology without carbon credit support. Nevertheless, the current price of carbon credit cannot induce the company to invest in CCS as well.

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LIST OF ABBREVIATIONS

ASME	American Society of Mechanical Engineers
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
DCF	Discounted Cash Flow
CERs	Certified Emission Reductions
CDM	Clean Development Mechanism
GHG	Greenhouse Gases
IRR	Internal Rate of Return
MM$	Million US Dollar
MM€	Million Euro
MCS	Monte Carlo Simulation
NPV	Net Present Value
PDF	Probability Distribution Functions

NOMENCLATURE

$MtCO_2$	million metric tons of Carbon dioxide
p	pressure
p_i	initial reservoir pressure
Pas	pascal second
t	time
tCO_2	ton of Carbon dioxide
y	year

GREEK LETTERS

ρ	density
Φ	porosity
μ	fluid viscosity
Δ	difference operator

CHAPTER I

INTRODUCTION

1.1 General Statement

Global warming is considered to be a major problem for the worldwide environment. By the efforts of the IPCC (International Panel on Climate Change) and others, global warming and the contrary effects on the environment are now considered as highly probable and are creating and raising awareness. Far reaching measures will be necessary to at least limit the global warming effect. This requires a transition towards a more sustainable energy supply characterized by less dependency on fossil fuels. In the period of transition however extensive measures are required to mitigate the effects of global warming.

Emissions of greenhouse gases are expected to cause climate change. The main greenhouse gas is carbon dioxide (CO_2), the most important greenhouse gas which causes global warming. The most recent international effort to address the greenhouse effect was the Kyoto Protocol, an agreement among the industrialized nations of the world to reduce emissions of six greenhouse gases over a certain period of time under the United Nations Framework Convention on Climate Change (UNFCCC).

The oil and gas industries in Thailand contributes to climate change by creating direct emissions from operational activity (recovery and treatment facility) which include CO2 and methane, resulting in serious problem for climate. Hence, E&P companies begin to encounter the problem by reduction of emission amount of greenhouse gases such as carbon dioxide, methane, nitrous oxide, ozone and chlorofluorocarbons (CFCs) while the Kyoto Protocol attempts to achieve global climate protection and cost minimization by introducing an innovative mechanism for cooperation in climate protection between industrialized and developing countries which is Clean Development Mechanism (CDM).

Currently Carbon dioxide Capture and Storage (CCS) is considered to be one of the most feasible and cost effective options for the transition period, as recently elaborated in an extensive IPCC Special report (IPPC 2005). CCS systems are specifically designed to remove CO_2 at major emission sources like refineries and power stations, transported by pipeline or ship to a suitable sink and stored in depleted natural gas reservoirs, aquifers, etc. or used for enhanced oil or gas recovery. Therefore, the feasibility study of the CCS technology for natural gas instead of emission directly to atmosphere should be studied. The objectives of this project are not only considered economical aspect, but also considered environmental and energy conservation aspects as well.

Figure 1.1: Location of A-20 gas field

In this study one of an offshore gas field is reviewed. Figure 1.1 shows an "A-20" offshore gas field. The case study gas field is located in Gulf of Thailand, at a distance of 200 kilometers from the Songkhla coast. The 4,000 km^2 field produces natural gas approximately 350 MSCF per day which contains 28-30 percent of CO_2. In order to meet sale specification, company has to reduce CO_2 to 23 percent before selling. The process leads to emit CO_2 around 835,000 tons annually (2,800 tCO_2 per day) which are the cause of global warming.

Rather than flaring the removal gas, the CCS will take into account this problem by re-injecting the CO_2 into underground. Figure 1.2 illustrates the project boundary. The boundary contains all and only the equipment and machinery which are associated with the compression, transportation, injection and storage of CO_2.

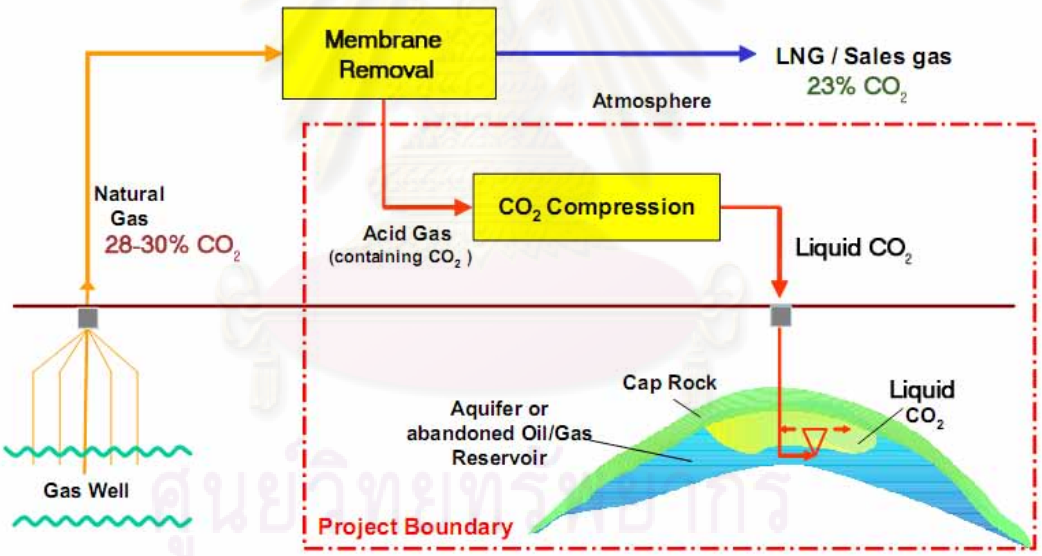


Figure 1.2: Project Boundary

The most significant emission in the baseline scenario is the CO_2 emissions from the membrane removal facility. In this methodology, the amount of the CO_2 emission from the membrane removal facility is considered to be equal to the amount of CO_2 injected. The CO_2 separated from the natural gas using membrane removal which is located in production platform and recompress again into liquid phase for injecting below seafloor or abandoned oil/gas reservoir.

1.2 Objectives

The main objective is:

- to perform pre-feasibility study in order to apply CCS technologies with the development of gas field in Thailand.
- to evaluate the effect of cost from CCS technologies to financial of the project.
- to establish how the CDM can provide economic incentive to CCS project.

1.3 Methodology

To estimate the economics of CO_2 capture, transport and injection in A-20, the amount of gas production has been evaluated in order to determine suitable CCS facilities; i.e. number of injection wells, size of pipeline and capture technology.

After gathering costs of the facilities, a stochastic assessment is performed for each project using the Monte Carlo simulation. First, the distributions of input parameters (CAPEX, OPEX and CERs) are determined and, next, simulations are performed by input parameters. The sampling method of simulation for the risk analysis is Monte Carlo Simulation (MCS) technic. The number of trials is limited to 5,000 and performed by commercial software. Finally, the data can be retrieved from the simulations which are NPV and IRR by using general economic concepts. The cash flow from CCS project will be combined with an existing cash flow of this gas field for evaluating the economic feasibility.

1.4 Thesis Outline

Chapter I Introduction thesis background, problems, objectives, and methodologies.

Chapter II Review previous works relating with this study which are composed of three parts: (1) review of exist CDM by UNFCCC which is applicable and concerning with this project and (2) review of the CCS projects that can be applied to this study.

Chapter III Describe an overview of CDM and currents status of CDM in Thailand.

Chapter IV Provide information of CCS system in terms of general detail and technical for using in this case study.

Chapter V Describe details of economic for evaluating the project which are included cost of investment, cash flow model, and Monte Carlo Simulation technic.

Chapter VI Present and discuss the study results from economic analysis.

Chapter VII Provide conclusions of this study and recommendations for further study based on this study point of view.

CHAPTER II

LITERATURE REVIEW

This chapter provides an overview of previous research on topics which are related to this study. It introduces the framework for the case study that comprises the main focus of the research described in this thesis. The main sections are divided in 3 parts: 2.1 Carbon Capture and Storage (CSS) Technology, 2.2 Clean Development Mechanism and 2.3 Economics analysis.

2.1 Carbon Capture and Storage (CCS) Technology

The aim of Carbon Capture and Storage (CSS) Technology is separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere. These studies are consistent with other researchers who investigated the same responses for these four groups.

An overview of CCS from UNFCC's paper [1] is studied. A new base methodology for carbon dioxide capture and storage (CCS) for gas reservoir is proposed for the project title "The capture of CO_2 natural gas processing plants and liquefied natural gas (LNG) plants and its storage in underground aquifers or abandon oil/gas reservoir". They involves setting up additional facilities to LNG complex to compress the recovered CO_2 which would otherwise have been released, to over the supercritical pressure and transfer it to a new sub-sea facility through a pipeline and inject it into an underground aquifer in the Pudina filed (Malaysia), and store the CO_2 in safe, sound and stable condition in underground geologic formation, and this reduce the CO_2 emission to atmosphere. The study significantly reduces an amount of CO_2 3 million tons per year and baseline and monitoring methodologies currently under consideration by the CDM Executive Board.

The study by Md Faudzi Isa and Muhammad Akkil Azhar [2] focus mainly on the application of CO_2 removal plant on offshore platform. Authors said that the selection of the optimum technology for CO2 removal is specific for each application.

The factors governed are among others are reservoir conditions, feed gas rate and composition operating pressure and temperature conditions, cost of product gas and fuel, availability and cost of utilities and environmental regulations. There are many projects which are suing membrane. Cakerawala platform an offshore processing facility in Block A18 of the Malaysia – Thailand Joint Development Area in the Gulf of Thailand, installed semi permeable membranes for CO_2 removal after evaluating several other technology options. The Cakerawala production platform (CKP) which uses NATCO/Cynara semi permeable membranes was successfully commissioned in December 2004 and is currently continuing to operate. The study also compares advantages of membrane and liquid solvent technologies. In conclusion, the use of membrane is more promising because it occupies less platform space and requires lower energy to operate.

Detail of transportation and injection well are important to estimate the capital investment of CCS. A. Shafeen, et al studied [3] the estimated cost of sequestration of 14,000 ton/day of CO_2 in Ontario and cost estimation includes only the pipeline transportation and storage into the reservoir. A calculation of number of well has been performed based on Darcy's law and the flow rate calculated by this calculation only gives an indication of the injection rate and deviation may occur in a practical situation. Finally, they concluded that the cost of the injection wells may vary from 22.5 to 95 MMUS$ depending on the total number of wells required at different flow rates.

T.N. Vermeulen [4] investigated the estimation of the required costs for the offshore facilities for the injection of CO_2 in depleted gas fields at the North Sea. The study consist of an analysis of the required process facilities at the platforms, cost estimation of the offshore facilities if existing gas production platforms are reused for CO_2 injection and a cost estimate for a typical new CO_2 injection platform. Author stated that new platforms are much more expensive compared to the modified existing platforms. Average cost per injection well for reuse of existing platform is eight or nine times lower than the new platform. This is mainly resulting from the cost to drill and complete new wells. There is mainly difference in construction which is the cost of the new platform, since the process facility costs are almost equal. The operational costs for new platforms are lower, because it can be specifically designed for low maintenance and attendance. However, the new platform is still necessary in case of limitation of the space of existing platform. This study also provide short reviews about options for CO_2 transport to the injection platforms and it is recommended that transport by pipelines in the liquid phase is the best option.

2.2 Clean Development Mechanism (CDM)

Guideline of CCS project under the Clean Development Mechanism is studied following “CDM Country Guide for Thailand” [5]. The main issues addressed are: CDM project cycle, possible CDM project in Thailand, CDM-related government authorities, project approval procedures and requirements and government support and incentives. Authors report that the energy and waste sectors (waste-to-energy options) offer the largest potential for CDM projects in Thailand and it is estimated that by 2020 the two sectors will generate 400 million tons of CO_2 equivalent ($MtCO_2e$) per year, accounting for 75 percent of total emissions. In addition, agriculture is the second largest sector for potential CDM projects because of emissions from rice cultivation and livestock. There are also opportunities in the forestry, waste, and industrial processing sectors.

CDM activities in Thailand are reported by “CDM Country Fact Sheet” [6]. The paper informs a current status CDM in Thailand. In June 2010, Thailand issued Letter of Approval 107 CDM projects, 35 projects had been registered at CDM executive board. Most of the projects in Thailand are either biomass energy generation or biogas energy generation by utilizing waste water from pig farm, palm oil mill, and tapioca mill. CDM project approval in Thailand is regulated so that it receives approval from the Board of Thailand Greenhouse Gas Management Organization (TGO Board) within 180 working days. The Letter of Approval (LoA) is to be signed by the Permanent Secretary of the Ministry of Natural Resources and Environment. Following regulation of the TGO Board process, CDM projects in Thailand take consideration of the Project Design Document (PDD) in order to determine whether the project meets all the requirements, including the sustainable development criteria.

2.3 Economics Analysis

A probabilistic analysis is used to quantify the impact of uncertainty and variability in cost model parameters in this thesis. The distribution of the NPV can be determined from the variables that affect project performance, resulting its average or the expected Present Value by using Monte Carlo Simulation. Fateh Belaid and Daniel De Wolf [7] introduced and attempted to explain the evaluation and risk analysis criteria of investment projects in upstream oil based on cash flows, showing how the Monte Carlo Simulation (MCS) and Sensitivity Analysis (SA) can be useful. The Monte Carlo method has the advantage of being based on estimated cash flows and therefore fits perfectly into the development strategies of exploration and production projects that focus on finding solutions that create the worth. Authors suggested that the Monte Carlo Simulation is one of the most efficient risk analysis project, because it is the only method that is able to integrate the various dimensions of a problem.

Main of economic parameters is quantified in a probability based distribution functions studying various uncertain economic characteristics. The parameters that are applied for the models are adapted by J.M.A. Rodriguez's study [8]. This study aimed to maximize the worth of the company while accounting, investigating and analyzing the inherent uncertainties and requirements of the petroleum industry. Author performed Monte Carlo simulation and provided the models of distributions that represent input parameters, which are commonly used in petroleum industry. The author also believed that the true value of portfolio management applied to the petroleum industry is not to provide a certain and unique answer but to gain insights into what makes a desirable portfolio for the company than an undesirable one.

Tomas Nauclér [9] also explains uncertainty over how costs will develop with time. Author compares cost level of CCS at different stages of development from initial demonstration projects, to early commercial and, eventually, matures commercial projects. For the reference case of new coal power installations, CCS costs could come down to around €30 to €45 per tCO_2 abated in 2030 which is in line with expected carbon prices in that period. By Figure 2.1, Nauclér found that early demonstration projects will typically have a significantly higher cost of €60 to €90 per ton, early full commercial scale CCS projects are expected to cost in the range of €35 to €50 per tCO_2 .With operating experience and scale effects, it is estimated that these costs can drop to €30 to €45 per tCO_2 abated by 2030. The author also said that storage is a key uncertainty that will determine the shape of the CCS roll-out. His team believes that there is sufficient storage potential in Europe for at least several decades. Depleted oil and gas fields, one key option, are well known and lie mostly in the North Sea, while deep saline aquifers, the other key option, are more widespread but also less researched and understood. In an ideal case, deep saline aquifers will be available locally for main emission clusters, but it is possible that longer transport and offshore storage may be required for some areas.

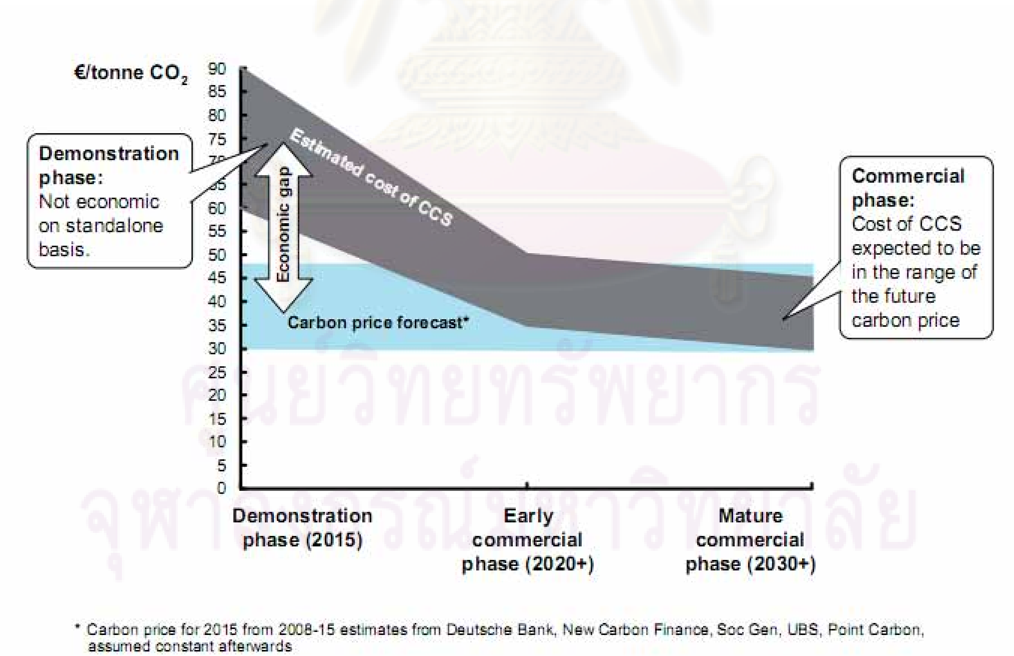


Figure 2.1: Forecast chart of development of CCS and carbon price

Besides, the Special Report on Carbon Dioxide Capture and Storage by the Intergovernmental Panel on Climate Change (IPCC 2005, Table SPM.5) [10] summarized a very wide range of cost estimates for the major steps of the CCS process: 1) capture, 2) transport, and 3) storage, monitoring and verification. The capture cost for coal and gas-fired power plants was assessed to be 15-75 US$/t$CO_2$ captured. The capture from hydrogen and ammonia production or gas processing was 5-55 US$/tCO2 captured. Capture costs from other industrial sources were 25-115 US$/tCO2 captured. The cost for transportation via pipeline was assessed to be 1-8 US$/tCO2 transported 250 km by pipeline for a scale of 5-40 million metric tons CO_2 per year (MtCO_2/yr). The cost of geological storage, monitoring and verification was assessed to be 0.6-8 US$/tCO2 injected without including any cost offsets that might occur if CO_2 were used for enhanced oil recovery (EOR). So, summary cost of CCS and the overall cost could be 16.6-131 US$/t$CO_2$. In summary, these cost estimates indicate the cost of capture dominates the cost of CCS, and there is a wide range of capture cost estimates.

CHAPTER III

CLEAN DEVELOPMENT MECHANISM

This chapter provides Clean Development Mechanism (CDM) theory and some of the CDM terminologies and rules. The CDM has its own specific modalities and procedures, and this chapter also explains general information of CDM. It's composed of 4 parts which are overview of the CDM, CDM project cycle, credit period, and currents status of CDM in Thailand.

3.1 General Overview of the CDM

The CDM is a mechanism where Annex I countries with a specific obligation to reduce a set amount of greenhouse gas (GHG) emissions by 2012 under the Kyoto Protocol assist non-Annex I countries to implement project activities to reduce or absorb (sequester) at least one of six GHGs (see Table 3.1 and Figure 3.1) The six GHGs are not equal In terms of global warming potential (GWP) [5], which measure the relative radioactive effect of GHGs compared to CO_2. For example, one ton of methane has a GWP as potent as 21 tons of CO_2. Non-Annex I countries are signatories to the Kyoto Protocol; however, they do not adhere to reduction targets stipulated under the protocol. The reduced amount of GHGs becomes credits called certified emission reductions (CERs), which Annex I countries can use to help meet their emission reduction targets under the protocol.

Table 3.1: The six greenhouse gases addressed under the Kyoto Protocol

Greenhouse gas	Global warming potential
Carbon dioxide (CO2)	1
Methane (CH4)	21
Nitrous oxide (N2O)	310
Hydrofluorocarbons (HFCs)	140–11,700
Perfluorocarbons (PFCs)	6,500–9,200
Sulfur hexafluoride (SF6)	23,900

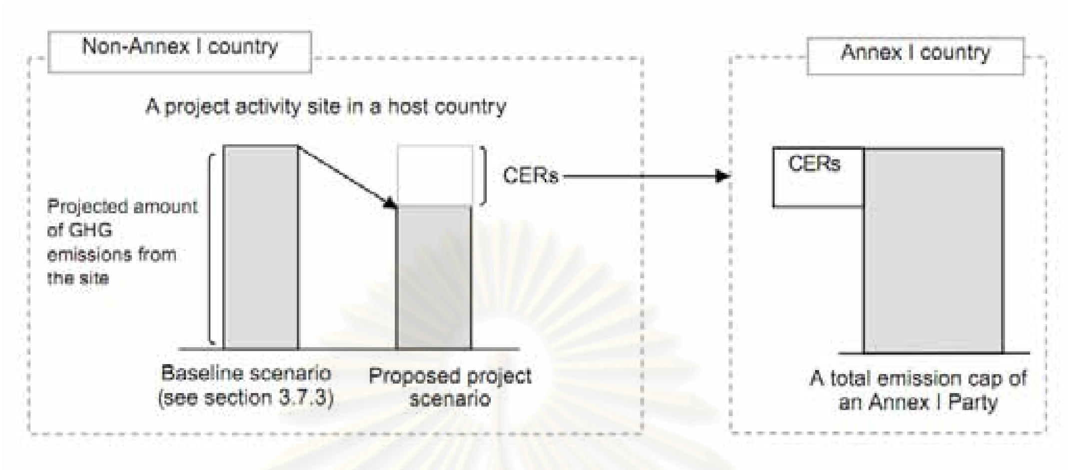


Figure 3.1: Diagram of how the CDM functions

3.1.1 Classification of CDM Project Activities

CDM project activities can be classified in two main areas: (1) GHG emission reductions and (2) sequestration (sink). Within these two main categories, there are sub-categories based on project size (Figure 3.2).

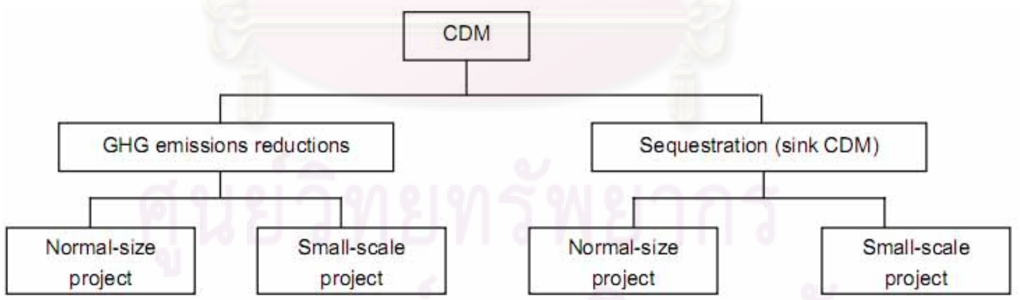


Figure 3.2: Classification of sub-categories of CDM project activities

3.1.2 The Baseline

Establishing a "baseline scenario" (or commonly referred to as "baseline") the crucial part of designing a CDM project activity. It sets the "base" from which the amount of total GHG emission reductions and credits is calculated. The baseline scenario describes what the current level of GHG emissions is prior to introducing the proposed CDM project activity. As shown in Figure 3.3, whatever the amount of emissions reduced or sequestered within a given project boundary during the crediting period will be accounted as the direct emissions reduction.

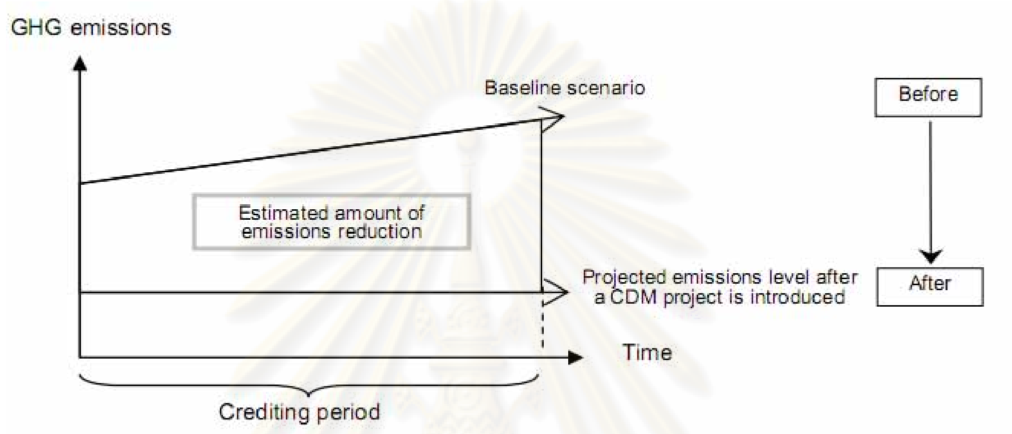
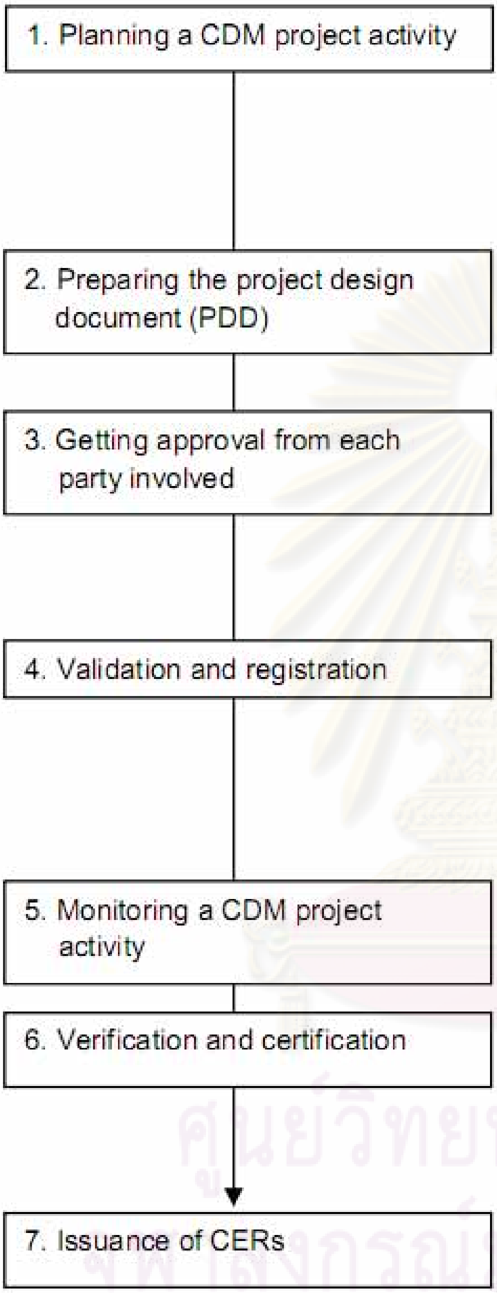


Figure 3.3: Baseline scenario

3.2 CDM project cycle

The CDM Executive Board was established as the UNFCCC Secretariat to oversee the CDM process [5]. In order to be registered as a CDM project activity, project proponents need to go through the steps detailed in Figure 3.4.



1. **Project participants** should consider that
(a) the planned project activity will assist the host country's sustainable development,
(b) the planned project activity is additional, and
(c) the planned project boundary is eligible, in the case of an A/R CDM project activity.

2. **Project participants** should
(a) download the standard PDD form from the UNFCCC Web site and complete it according to the guidelines provided by the CDM EB.

3. **Project participants** should
(a) learn about the approving process of concerned Parties and all the requirements from designated national authorities (DNAs), and
(b) obtain the written approval of voluntary participation from the DNAs.

4. **Project participants** should
(a) have the validation done by a designated operational entity (DOE) accredited by the CDM EB, and
(b) pay a registration fee to the CDM EB. The **DOE** will submit all necessary documents to the CDM EB and request project registration.

5. **Project participants** should
(a) monitor according to the monitoring plan and report to the operational entity.

6. The **operational entity** should
(a) verify the monitoring results and certify the exact amount of GHG emissions reduction resulting from the project activity, and
(b) report the result to the CDM EB.

7. The **CDM EB** will
(a) issue a certified amount of CERs within 15 days after receiving a request for issuance, and
(b) deduct a "share of proceeds" from the issued CERs.

Figure 3.4: Overview of the CDM project cycle

3.3 Credits and Crediting Periods

One of the main features of CDM project activities is that they are able to generate tradable emission credits (CERs). However, Non-Annex I Party participants can sell or transfer the credits to Annex I Party participants. In additional, non-Annex I Party participants are not allowed to freely trade the credits in the emissions trading market. Table 3.2 summarizes the different options for the crediting period and types of credits to be issued for GHG emissions reduction and A/R project activities.

Table 3.2: Credits and crediting period for CDM project activities

	GHG mitigation project activities	**A/R project activities**
Crediting Periods	i. 7 years with the option of renewing twice (total crediting period = 21 years.	i. A maximum of 20 years with an option of renewing twice (total crediting period = 60 years.
	ii. 10 years without the renewal option.	ii. A maximum of 30 years without the renewal option.
Types of Credits	CERs	i. Temporary CERs (tCERs): The net GHG removals by sinks achieved by the project activity since the project starting date, which should be replaced by other Kyoto Protocol credits before the end of the subsequent commitment period.
		ii. Long-term CERs (lCERs): The net GHG removals by sinks achieved by the project activity during each verification interval.

3.4 Currents Status of CDM in Thailand

Thailand is a Party to the United Nations Framework Convention on Climate Change (UNFCCC), which the Thai government signed on June 12, 1992, and ratified on December 28, 1994. The UNFCCC went into force on March 28, 1995. Thailand later made further steps toward climate change mitigation by adopting the Kyoto Protocol in February 1999 and ratifying it on August 28, 2002. Since ratification of the UNFCCC and the Kyoto Protocol, actions and programs have been initiated to promote energy conservation and carbon sinks at the national level.

Thailand Greenhouse Gas Management Organization (TGO) is the Designated National Authority (DNA) in Thailand and was established on 6 July 2007. Prior to the establishment of the TGO, the Office of Natural Resources and Environmental Policy and Planning (ONEP) was the DNA office. So far, Thailand issued Letter of Approval (as of June 2010) to 107 projects. Among those projects (Table 3.3), Thirty five projects had been registered at the CDM Executive Board. Most of the projects in Thailand are either biomass energy generation or biogas energy generation by utilizing waste water from pig farm, palm oil mill, and tapioca mill.

Table 3.3: Basic data on CDM project (as of 1 June 2010)

	Registered CDM projects				
	No. of project	Annual emission reduction (tCO_2)	Total ERs by 2012 (tCO_2)	Amount of issued CERs	Rejected
Biogas (Wastewater Treatment)	19	58,637	5,950,565	714,546	
Biogas (Animal Waste)	4	25,684	435,426		
Biomass (Bagasse)	3	85,890	1,965,827		
Biomass (Rice Husk)	3	44,792	638,020	100,678	1
Methane recovery &	2	82,897	727,837		

utilization					
Waste heat utilization	2	36,338	195,908		
N_2O reduction	1	142,402	504,719		
Biomass (EFB)	1	106,592	422,929		
Total	**35**	**59,878***	**10,886,231**	**815,224**	**1**

*This value is not the total of average annual emission reduction of each project type, but average annual emission reduction of all the seven project types.

CHAPTER IV

CARBON CAPTURE AND STORAGE (CCS)

Carbon Capture and Storage (CCS) has been defined by Intergovernmental Panel on Climate Change (IPCC) under United Nations Framework Convention on Climate Change (UNFCC) as "the process consisting of the separation of CO2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere". The system composes of three main components: capture, transport and storage. The capture step takes separating CO_2 from other gaseous products. For fuel burning processes such as those in power plants, separation technologies can be used to capture CO_2 after combustion. The transport step is required to carry captured CO_2 to a suitable storage site. To facilitate both transport and storage, the captured CO_2 gas is typically compressed to a high density at the capture facility. Potential storage methods include injection into underground geological formations, injection into the Deep Ocean, or industrial fixation in inorganic carbonates.

In this chapter, details of CCS can be separated into 6 parts based on function and procedure of CCS system: 1) CO_2 removal 2) CO_2 compression 3) CO_2 transportation 4) CO_2 injection 5) CO_2 storage and sequestration and 6) Application of CCS to case study.

4.1 CO_2 Capture

The capture techniques examined in this study are commonly used on an offshore platform. Developing high CO_2 offshore gas field projects had made extensive evaluation on several processes for gas separation namely chemical absorption (amine), physical absorption, cryogenic distillation (Ryan Holmes process), membrane system and other current technologies. The following sections present basic principal of amine solvent and membrane removal technologies. There are also compared advantages and disadvantages in terms of applications for offshore works.

4.1.1 Amine Solvent Technology

The currently favored chemical solvent technology for carbon capture is amine-based chemical absorbent. For a basic principal of the amine solvent method, CO_2 in the gas phase dissolves into a solution of water and amine compounds. The amines react with CO_2 in solution to form protonated amine (AH^+), bicarbonate (HCO_3^-), and carbamate (ACO_2^-). As these reactions go on, more CO_2 is driven from the gas phase into the solution because of the lower chemical potential of the liquid phase compounds at this temperature. When the solution has reached the intended CO_2 loading, it is took out from contact with the gas stream and heated to reverse the chemical reaction and release high-purity CO_2. The CO_2-lean amine solvent is then recycled to contact additional gas. The flue gas must first be cooled and treated to remove reactive impurities such as sulfur, nitrogen oxides, and particulate matter. Otherwise, these impurities may react preferentially with the amines, reducing the capacity for CO_2, or irreversibly poisoning the solvent. The resulting pure CO_2 stream is retrieved at pressures near atmospheric pressure.

Simple combinations of alcohols and ammonia can form Alkanolamines. The Alkanolamines are the most commonly used category of amine chemical solvents for CO_2 capture. Reaction rates with specific acid gases differ among the various amines. In addition, amines vary in their equilibrium absorption characteristics and have different sensitivities with respect to solvent stability and corrosion. Alkanolamines can be separated into three groups [11]:

- Primary amines, including monoethanol amine (MEA) and diglycolamine (DGA)
- Secondary amines, including diethanol amine (DEA) and diisopropyl amine (DIPA)
- Tertiary amines, including triethanol amine (TEA) and methyldiethanol amine (MDEA)

MEA, relatively inexpensive and the lowest molecular weight, is the amine that has been used extensively for the purpose of removing CO_2 from natural gas streams. MEA has a high enthalpy of solution with CO_2, which tends to drive the dissolution process at high rates. However, this also means that a significant amount of energy must be used for regeneration. In addition, a high vapor pressure and irreversible reactions with minor impurities such as COS and CS_2 result in solvent loss.

4.1.2 Membrane Technology

Figure 4.1 shows membrane removal schematic. It is a thin semi permeable barrier that selectively separates some fluids from others. Basic principle of membrane removal is to separate different permeation velocities of different gases through a certain membrane material. The processes are driven by differences in driving force such as the pressure or concentration of the components across the membrane.

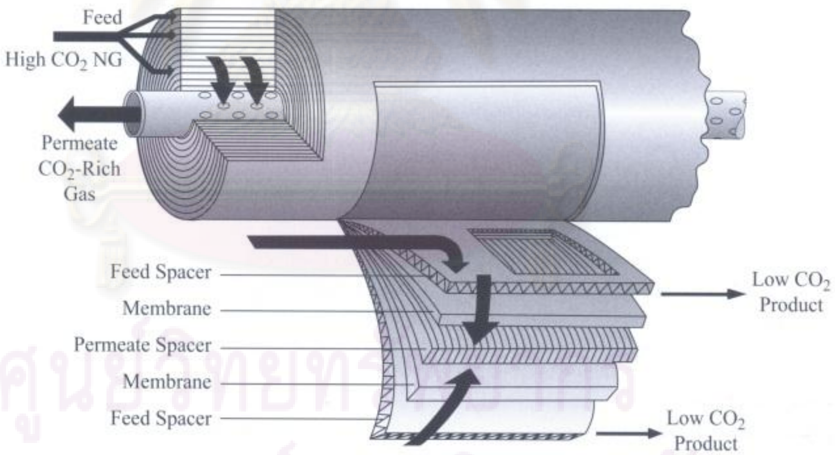


Figure 4.1: Membrane removal

Membrane is ideal for bulk removal of CO_2 to meet product gas specification with high CO_2 percentage levels. For proper membrane operation and to ensure long service life, proper pretreatment of the feed gas is essential. Pretreatment essentially removes water and heavy hydrocarbon components in the gas that could damage the membrane. Pretreatment can be in the form of dehydration and chilling to knock off heavy ends or by adsorption of the heavy ends using molecular sieves. Disadvantage issues in membrane facilities resulting in short membrane life and inability to achieve design capacity is mainly caused by inadequate or poor pretreatment. Membranes are also sensitive to rapid thermal and pressure variations in the feed gas conditions. Uncontrolled thermal and pressure swings can shorten membrane life.

Membrane performance develops over time. Flow through the membrane has to be set based on the performance and condition of the membrane. Gas chromatograph set up on the product stream allows operator to monitor the membrane performance and to make the necessary flow adjustment to optimize its operation.

4.1.2.1 Type of membrane

Membrane comes in two most common forms. Table 4.1 compares two types of membrane, hollow fiber and spiral wound. Hollow fiber has strength limitation but its construction maximizes surface area per unit volume of membrane. The common materials for constructing membrane are cellulose acetate derivatives, polyimide, polyamide and polysulfon [2].

Table 4.1: Advantages and disadvantages of each type of membrane

TYPE OF MEMBRANE	ADVANTAGES	DISADVANTAGES
Hollow fiber	• Greater amount of membrane surface area within a given volume. • Ability to operate effectively in the presence of heavy hydrocarbons.	• Limited maximum operating pressure. • Strength reduces with increasing CO_2 concentration.
Spiral wounds	• Able to withstand relatively high pressures	• Hydrocarbon condensation may not be easily removed

	• Minimum permeate pressure drop.	and liquid accumulated inside reduces the productivity of membrane.

Many optimizations are possible for hollow fiber elements. They include adjusting fiber diameters: finer fibers give higher packing density but larger fibers have lower permeate pressure drops and so use the pressure driving force more efficiently.

4.1.2.2 Compare between membrane and chemical solvent

In the meantime, the use of membrane is also more promising if compared to liquid solvent technologies. Some explanations the statements above are as follows:

1. Membrane technology requires lower energy to operate than chemical absorption process leading to saving in equipment to generate the power and cost of facilities.
2. Membrane technology has less rotating equipment resulting in less working and maintenance requirement.
3. The treated gas from membrane is dehydrated and can be exported directly into the sales gas pipeline. Amine treated gas is water saturated and requires additional equipment for drying the gas. Membrane treated gas is very dry (unlike gas dehydrated by TEG system) with no risk of corrosion in the gas export pipeline.
4. There is no solvent and chemical make-up that requires additional space on platform for chemical handling and storage. The need to replenish solvent and chemicals will add to logistics and transportation costs.
5. Membrane units are simply to operate with low operator intervention and have no foaming and corrosion problems.

6. Membrane systems occupy less platform space than amine systems leading to smaller platform resulting in significant cost saving
7. Membrane systems avoid the need to have a fire source on the platform which is a potential source of firing in a hazardous situation involving the release of hydrocarbon gases. The low heating duties can be supplied by hot oil heating medium recovering waste heat from the turbo generator exhaust gas.
8. Single stage membrane is more economical than the chemical absorbent system. The high cost of the chemical absorbent system is attributed to the need for an additional offshore structure to locate the future 3rd compression train. A larger flare support structure to locate the thermal oxidizers and waste heat recovery units partly contribute to the overall cost.

By removal CO_2 offshore will not only reduce the corrosion problems but also reduce the size of the export gas pipeline and decrease the compression power. The selection of the optimum technology for CO_2 removal is specific for each application. There are many factors need to be concern which are reservoir conditions, feed gas rate and composition, operating pressure and temperature conditions, cost of product gas and fuel, availability and cost of utilities and environmental regulations. His study undertaken with design consultant, technology provider and in house experts had led to a determination that membrane is the most promising, effective and economical way to deal with offshore CO_2 removal due its compact size, moderate utility consumption, easy operation and reliability. In undertaking the selection process, the following selection criteria were used. There are CAPEX, OPEX, Operating Flexibility, Reliability, Expandability, Environment Friendly, Weight, Foot print, CO_2 Removal Efficiency, CO_2 purity.

4.1.2.3 Design Considerations for Membrane

Many process parameters which are involve in membrane removal system can be adjusted to optimize performance depending on the application needs. Some typical requirements are:

- Low cost
- High reliability and easy to operate
- High hydrocarbon recovery
- Low maintenance
- Low energy consumption
- Low weight and space requirement

Many of these requirements work against one another: for example, a high recovery system usually requires a compressor, which increases maintenance costs. The design engineer must therefore balance the requirements against one another to achieve an overall optimum system.

Figure 4.2 provides the percentage hydrocarbon recovery is plotted versus percentage CO_2 removal for one and two-stage systems at certain process conditions. The percentage hydrocarbon recovery is defined as the percentage of hydrocarbons recovered to the sales gas versus the hydrocarbons in the feed gas.

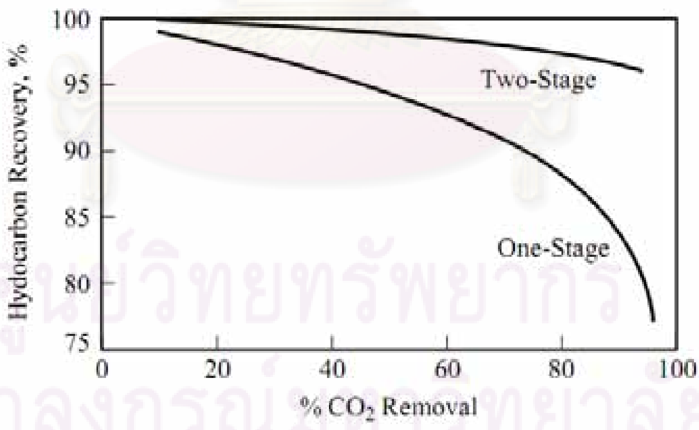


Figure 4.2: Effect number of stages

The hydrocarbon recovery of a two-stage system is significantly better than that for a single stage system. However, when deciding whether to use a single or multistage approach, the designer must also consider the impact of the recycle compressor. This impact includes the additional hydrocarbons used as fuel, which increases the overall hydrocarbon losses, as well as the significant capital cost of compressors and the difficulty of maintaining them in remote locations. In this study, CO_2 removal applications, that is, below approximately 50%, single-stage membrane systems not only remove CO_2 to meet the sale specification but also provide better economic returns than do multistage systems.

4.2 CO_2 Compression

To transport CO_2 efficiently by pipeline the pressure needs to lie in between 8,619 kPa at 4°C and 15,300 kPa at 38°C [11]. At this pressure the density versus the compression ratio is in many cases optimal designs. Higher pressures require more energy and investment costs while there is little gain in density (i.e. smaller pipelines). Depending on the pressure drop over the pipeline in some cases higher entrance pressures are required. A four-step centrifugal compressor compresses the carbon dioxide. Water is removed during the first compression stages. Table 4.2 gives the main characteristics of compressors pressurizing from 0.1 to 12 MPa (1 bar to 120 bars).

Table 4.2: Operational conditions for compression

	1st stage	2nd stage	3rd stage	4th stage
Inlet/outlet pressure (bars)	1/3.8	3.8/10.3	10.2/38.3	120
Inlet/outlet temperature (°C)	30/155	35/128	35/165	35/152
Polytropic efficiency	85.4	84.7	83.6	76.8

Both the compressor size and pipeline diameter are calculated on the basis of the maximum design mass flow rate of CO_2, while the compression station annual power consumption is calculated on the basis of the nominal mass flow rate of CO_2. The compressor size is required to determine the capital cost of the compressor, while the compressor station annual power requirement is required to calculate operating cost.

4.3 CO_2 Transportation

Physical properties of CO_2 are relevant to its storage underground because they define the density and viscosity of the stored gas, and thus its occupied volume and mobility. They are also relevant because large volume changes are associated with CO_2 phase changes, so it might be suitable to store CO_2 under physical conditions that are not close to the phase boundary conditions in order to avoid unexpected volume and mobility changes [12]. Figure 4.3 shows the phase diagram of CO_2.

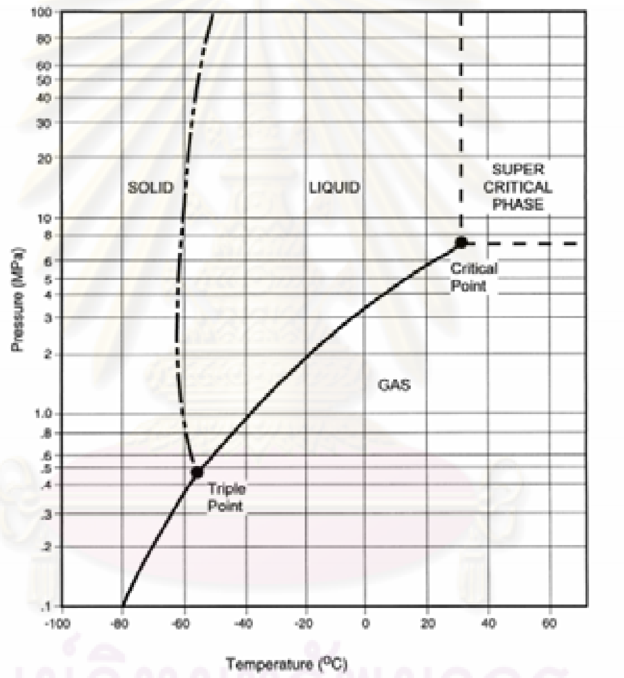


Figure 4.3: CO_2 Phase Diagram

From the phase diagram, CO_2 occurs as a solid, a liquid, a gas, or a supercritical fluid. Above its critical temperature of 31.1°C and critical pressure of 7.38 MPa (73.8 bars), CO_2 exists in the so-called dense phase condition, i.e., as a supercritical fluid. A supercritical fluid is a gas-like compressible fluid in that it fills and takes the shape of its container, but it has liquid-like densities. It is desirable to store CO_2 as a supercritical fluid or a liquid because of higher phase density that will occupy much less space in the subsurface. For example, one ton of liquid-CO_2 at a density of 785 kg/m^3 (i.e. 22°C and 7 MPa or 50°C and 15MPa) occupies 1.27 m^3, while at standard temperature and pressure, at the ground surface, one ton of CO_2 occupies 512 m^3.

4.3.1 CO_2 Transport Options

A review of the alternatives for CO_2 transport to the injection platforms was performed. The options studied are liquid transport by sea going vessels to the injection platforms, gaseous transport by pipelines to the injection platforms and supercritical transport by pipelines.

4.3.1.1 Liquid Transport by Ship

The transport of liquid CO_2 by ships is based on the existing technic of transporting LNG over sea. The CO_2 is sent into ships at cryogenic conditions, which are subzero temperatures and slightly elevated pressures. After reaching at the platform the CO_2 has to be pressurized and heated to injection conditions before injection in the well. Typical equipment required for this application are cryogenic pumps for increasing the pressure, open rack vaporizers or other heat exchange equipment using sea water for initial heating of the CO_2 and finally an additional heating step using natural gas or other fuel for heating up to injection temperatures. Compared to liquid transport by pipeline the transport of CO_2 by ship takes additional equipment offshore for conditioning of the CO_2 to injection conditions. For the intended bulk injection of CO_2 a large number of very expensive specialized CO_2 transport vessels have to be constructed. The costs involved in the construction of the specialized vessel and additional equipment located offshore, either on the ships or the platforms, is not determined in detail, but it is not likely it is a feasible option. A more detailed investigation is required if this option is feasible for other scenarios.

4.3.1.2 Gaseous Transport by Pipelines

Transport of CO_2 through pipelines in the vapor phase means transport at low pressures to prevent two phase flow in the pipelines. At approximately 40 bars and assuming an operating temperature of 4 °C, two phase flow already occurs. This implicates that the arrival pressure at the platforms is not sufficient for injection job and compressors have to be installed offshore. This is in conflict with the objectives to minimize offshore facilities and maintenance requirements. Second consequence is the low density of CO_2 at the mentioned conditions, which require very large transportation pipelines. This option for transport is assumed not viable for the large scale application under consideration. For small scale applications or for certain demonstration projects gaseous transportation might however be a viable alternative.

4.3.1.3 Supercritical Transport Through Insulated Pipelines

In contrast, the installation of insulated pipelines can make supercritical transport of CO_2 possible at elevated pressures and temperatures, for example at 100 bars and 70 °C. This may cut down the required amount of heating equipment at the offshore installations. A short analysis of this option suggested that the density of supercritical CO_2 for transport in insulated pipelines was approximately one third of the density in liquid transport. This result in an increase in pressure drop required for transportation at equal line size. The pipeline size required for the transport of supercritical CO_2 has to be increased to accommodate an equal mass flow of CO_2. Based on the increase in size, together with the requirement for expensive thermal insulation this option was regarded as not viable. An additional weakness is that the CO_2 may not be available for transport at temperature levels required for injection and additional offshore heating is still required. However, T.N. Vermeulen [4] states that transportation the CO_2 by pipelines in the liquid phase is the best option as to avoid any two phase mixtures. This enhances liquid phase transportation and enhances the economic benefits. The operating pressure and temperature lies in between 8.6 MPa at 4°C and 15.3 MPa at 38°C. The upper and lower limits are set, respectively, by the ASME-ANSI 900# flange rating and ambient condition coupled with the phase behavior of CO_2.

4.4 CO_2 Injection

CO_2 will be injected directly into a depleted or inactive reservoir without expectation of any further oil production. From the gas field data, CO_2 can be injected into depleted gas reservoir at 2,500-3,000 meters below sea floor. However, this study assumed that there is safely deposit the CO_2 in secure site and enough storage space deep underground in order to avoid leakage problems.

4.4.1 Number of Required Injection Wells

The approximate capacity of an injection well can be assessed by calculating the flow rate of carbon dioxide into the reservoir. An estimation of the preliminary flow rate [16] can be estimated by following equation 4.3,

$$q = \frac{\rho_r}{\rho_s} \times \frac{2\pi kh}{\ln \frac{r_e}{r_w} \mu} \times \Delta P \tag{4.3}$$

where q = flow rate (m^3/s)

ρr = density of the gas under reservoir conditions (kg/m^3)

ρ_s = density of the gas under standard conditions (kg/m^3)

k = permeability of the reservoir (m^2)

h = thickness of the reservoir (m)

r_w = radius of the well (m)

r_e = radius of the influence sphere of the injection well (m)

μ = viscosity of CO_2 at the well bottom (Pas)

ΔP = pressure difference between reservoir and well bottom pressure (Pa)

4.5 CO_2 Storage and Sequestration

Geological storage is the activity of injecting and containing CO_2 in a geological formation, such as an oil reservoir. Geosequestration refers to the collection of processes by which the CO2 becomes part of the reservoir rocks and fluid. For example, the CO2 can react with the water in the reservoir to become a bicarbonate. This type of reaction is considered permanent storage in the sense that the CO_2 is transformed into a substance that is part of the reservoir. Geological storage, on the other hand, refers to the fact that the CO_2 remains trapped as CO2 in the reservoir. In this study, this process is considered geological storage project because the sequestration reactions generally occur slowly over very long periods of time.

CO_2 sequestration methods can be divided into three groups based on its primary mechanism: 1) Injection and entrapment within pressure or structural boundaries, such as geologic storage and deep ocean storage, 2) use chemical boundaries, such as mineral carbonization, and 3) utilize aerobic uptake through biological means, such as photosynthetic bioreactors, or herbaceous means, such as terrestrial aforestation and ocean farming.

4.5.1 Geological Sequestration Methods

Geologic methods of sequestration involve the capture of CO_2 emissions and subsequent compression for transportation to a suitable disposal site for pressurized injection. In the geologic formation, suitable disposal sites include oil/natural gas wells that are either under producing or depleted. Deep saline aquifers and deep ocean injection are the location where pressure and temperature boundaries maintain CO_2 in its liquid phase.

4.5.1.1 Deep Saline Aquifer Injection

Deep saline injection implies to the injection of CO_2 into deep sedimentary basins, where pressure and temperature suitable of dense phase (liquid or supercritical) CO_2. Deep saline aquifers are favor and underlie many parts of the world, due to reducing the costs of infrastructure associated with pipeline construction. The storage capacity accompanied with this option is high, with a global capacity estimated between 300 and 10,000 $GtCO_2$. Residence time in saline aquifers is long ranging from hundreds to many thousand years, depending on the local hydrologic gradients.

4.5.1.2 Coal Bed Injection

Coal bed injection involves the injection of CO_2 into deep, unmineable coal seams, where the combined influence of physical trapping from low permeability surroundings and physical or chemical adsorption to the coal structure serves to contain the injected gas. As an additional benefit, the possibility of a recoverable reserve of methane presents an attractive economic solution.

4.5.1.3 Oil and Gas Reservoir Injection

Both depleted and active fossil fuel reservoirs are potential storage space for CO_2 in underground formations. CO_2 will be injected directly into a depleted or inactive reservoir without expectation of any further oil production, or the injection may result in enhanced oil (EOR) and gas recovery (EGR) and simultaneous CO_2 sequestration. The process will provide an economic benefit. Injection of CO_2 improves the mobility of the remaining oil and increases reservoir pressure which leads to incremental quantities of gas production.

4.5.2 Additional Sequestration Methods

There are 4 additional methods for sequestration following as;

4.5.2.1 Ocean Fertilization

The main is that the shallow ocean organisms are capable of naturally sequestering atmospheric CO_2. Shallow ocean waters will be seeded with nutrients to stimulate the growth of marine photosynthetic organisms. However, there is a drawback due to lack some key nutrients to make the rate of sequestration viable as an actual sequestration strategy. Currently, there are still a lot of unknowns about using this method as a viable sequestration strategy, which must be determined before it should be utilized.

4.5.2.2 Deep Ocean Injection

This process utilizes the ocean as a storage medium for containing either gaseous or liquefied CO_2. Injection of gaseous CO_2 to the ocean occurs at depths between 500 and 2,000 meters below the ocean. Next, the injection gaseous CO_2 will diffuse into the seawater and react to form carbonates which will then settle to the bottom. The other form of deep ocean injection is to inject liquefied (compressed) CO_2 at a depth greater than 3,000 meters where the density difference between the ocean water and the liquefied CO_2 will cause the CO_2 to settle downward where it will form a pool on the ocean floor. Research is ongoing to determine the effects of sequestering CO_2 through this method. Currently, the study states that the CO_2 pool into the deep ocean waters will cause the oceans pH to fall leading to an acidic ocean as well as the potential for an early release of the CO_2 back to the atmosphere.

4.5.2.3 Terrestrial Aforestation

Terrestrial sequestration is the net removal of CO_2 from the atmosphere or the prevention of CO_2 from leaving the terrestrial ecosystem. Since the terrestrial ecosystem involves soil and vegetation, various researches in this habitat focuses on means of improving land use management and soil texture in a way to enhance CO_2 sequestration. Therefore, CO_2 sequestration in the terrestrial ecosystem can be managed through various land use management.

(1) Afforesatation, reforestation and restoration of graded land
(2) Agro forestry on Agricultural lands
(3) Improving growth rate with the aid of required nutrients.

The limitations are lacking of availability of land, proper land and soil management will to an extent sequester a reasonable amount of CO_2 in to the terrestrial biosphere.

4.5.2.4 Mineral Carbonation

The main advantage of the process is the formation of mineral carbonates which are the end products of geologic processes and are known to be stable over geological time periods (millions of years). The process is also known as mineral sequestration which aims at trapping carbon in the form of carbonate salts. The basic concept is to transform minerals (mostly calcium or magnesium silicates) with CO_2 to geologically stable carbonates like magnesite or calcite. The most promising feedstock minerals are Olivine, Serpentine and Wollastonite. The environmental impact of mining, waste disposal and product storage could also limit potential.

4.5.3 Selected methods

Because of the scope and characteristic of the filed study, the field of options has to be selected. Ocean sequestration was got rid of because it had quite negative public perception and the environmental impacts were not well known. Mineralization was eliminated because it was exorbitantly expensive and is at an early phase of development as a technique for sequestering large amounts of captured CO_2. Terrestrial afforestation was eliminated because the land requirement was not available. Coal bed injection were eliminated because they were quite location limited in comparison to oil and natural gas injection method. Deep saline aquifer injection and was eliminated due to negative public perception and injecting CO_2 can acidify the fluids in the reservoir, dissolving minerals such as calcium carbonate, and possibly increasing permeability. The oil and natural gas injection was favor because it is very common in location and would not require large transport distances from existing sites and utilizes mature and well known technology.

4.6 Application of CCS to case study

In this section, the CCS project is applied to the A-20 gas field in order to reduction CO_2 emission into atmosphere.

4.6.1 Base case scenario

Describe the background of gas facilities and gas emission data

- The case study "A-20" gas field is located in Gulf of Thailand, at a distance of 200 kilometers from the Songkhla coast and the area of the field is approximately 4,000 square kilometers. The field development planning is to construct 2 Central Processing Platforms (CPP) with are composed of 70 platforms. The field contains original gas in place (OGIP) 5,258 Bcf. Natural gas production planning is totally 3,333 Bcf which is separated into CPP1 (1,989 Bcf) and CPP2 (1,341 Bcf). For condensate production, the individual CPP handles 8,000 bbl/d of condensate and mean reserves for all platforms is 45.5 million bbl. As shown in Figure 4.4, Daily Contract Quantity (DCQ) of

CPP1 and CPP2 are totally 300 MMscf/d which are produced through 33 years of project life.

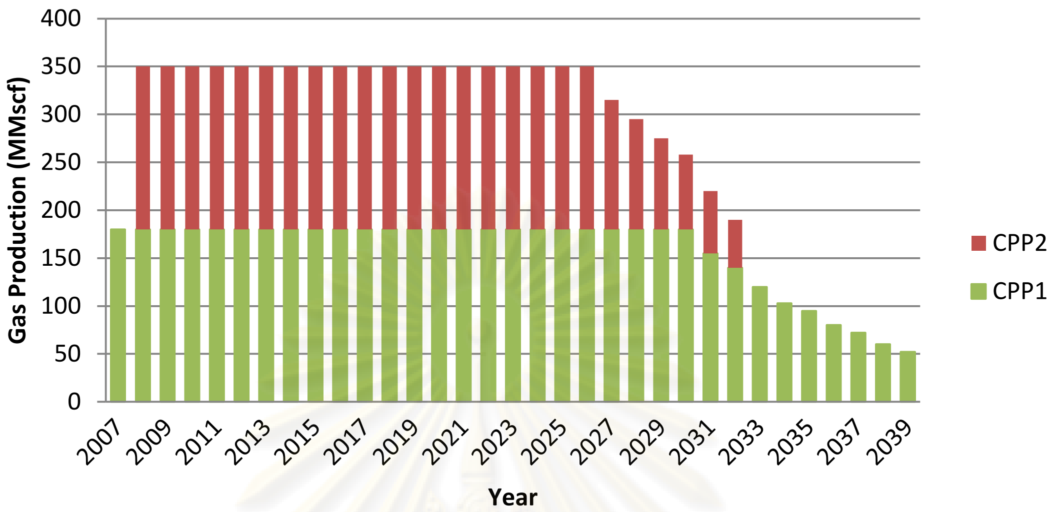


Figure 4.4: Profile of gas production

- The production of natural gas contains 28-30% of CO_2. The diagram of production process is shown in Figure 4.5. An amount of carbon dioxide in feed is removed by membrane removal technology on the production platform in order to meet sale specification of 23% of CO_2.

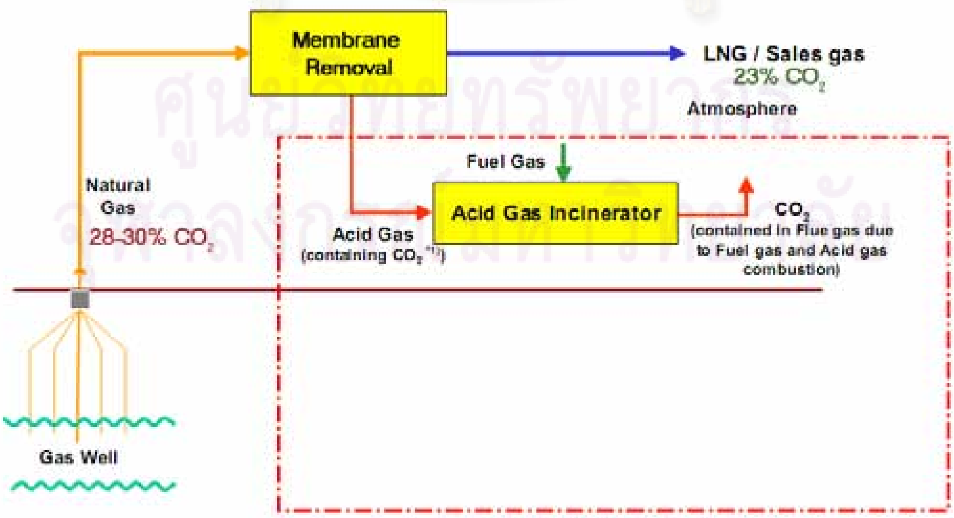


Figure 4.5: gas production process of base case

- Project development costs are provided in Table 4.4.

Table 4.4: Project development costs

Item	**Cost (Million US)**
Central Processing Platform (2)	490.50
Production Platforms (70)	288.00
Apprisal Well	33.00
Development Well	44.60
FSU	40.30
Pipeline	251.99
Abandonment	90.80
Operating Cost	967.07
Total	2,206.26
Total (10% Discounted rate)	**1,666**

Source: Department of Mineral Fuel (DMF).

- Table 4.5 presents profile of the amount of CO_2 emission in 33 years. The removed (permeate) waste stream will be transported and disposed by flaring which is equivalent into tCO_2 [Appendix A1].

Table 4.5: Amount of CO_2 emission

Year	Amount of emission (tCO_2 per year)
2007	562,592
2008	486,200
2009-2027	830,000
2028	887,465
2029	709,156
2030	583,818
2031	327,107

2032	598,496
2033	346,530
2034	274,536
2035	264,478
2036	220,736
2037	228,840
2038	179,109
2039	155,248

4.6.2 Applying CCS Technology

In order to study the pre-feasibility of using CCS in to this project, then the boundary of CCS project needs to determine. The boundary of CCS project for this study contains all of the equipment and machinery which is associated with consists of the compression, transportation, injection and storage of CO_2. Since the CO2 capture process has already been installed.

Once the CO_2 has been captured by membrane, efficient transport of CO_2 via pipeline requires that CO_2 be compressed and cooled to the liquid state so its pressure is boosted by booster compressor. Maximum of CO_2 emission from this field will be approximately 830,000 ton per year (density 0.700 g/mL) which is equivalent to 30 kg/s. Four-step centrifugal compressor (12,600 kW) compresses CO_2 from 0.1 to 12 MPa prior to being transferred pipeline. Calculation of CO_2 flowrate and compressor size are in Appendix 2A and 3A respectively.

According to calculation in Appendix A4, 6 inch diameter pipeline will be required. A larger diameter gives a higher margin of safety for occasional higher CO_2 flows. The corrosion-resistant pipeline transport is considered to be used. The liquid CO_2 will be transformed to the injection platform for injecting into the formation under the A-20 filed following in Figure 4.6 with no booster pumping stations. The injected CO_2 will be in a dense phase and has physical properties like a liquid under the assumption that there is no leakage involved in this methodology.

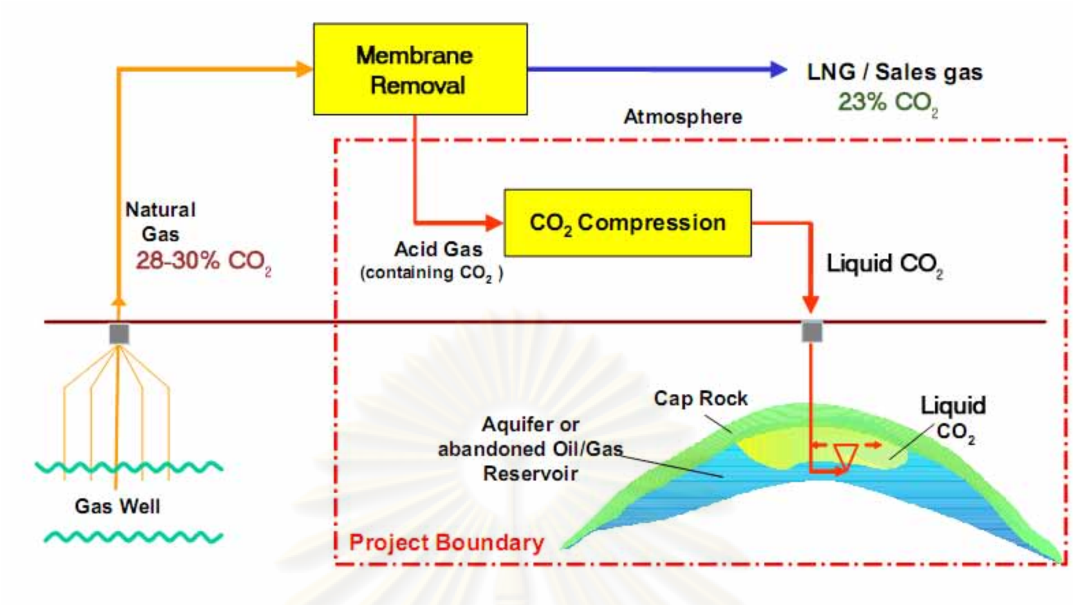


Figure 4.6: Project boundary

There is assumtion that no pressure boosting equipment is required in the injection platform, for the following reasons:

- pressure boosting from production platform, at the beginning of the transportation system, is much more efficient and therefore cost-effective than at the end of the pipeline;
- rotating equipment offshore adds to the operational complexity of the process, resulting in a high requirement for reliability driven manning and maintenance, hence costs;

Through 33 years, approximately 0.83 Mt of liquid CO_2 will be injected into deplete gas reservoirs. Three injection wells will be drilled and the calculation the number of well is performed by Darcy's law and presented following in Appendix A5. For the new platform structure the mono-tower concept is assumed. The structural weight of the new facility has been estimated by scaling known platforms based on empirical scaling relations and equipment weights as presented by Vermeulen [4]. Results are shown in Table 4.6.

Table 4.6 Structure weight new platform

Platform type		**Mono-tower**
Water depth	m	70
Process equipment weight	ton	299
Living quarters weight	ton	0
Life boat weight	ton	0
Crane weight	ton	20
Total equipment weight	ton	329
Structural topside weigh	ton	115
Total topside weight	ton	444
Total weight substructure	**ton**	**888**
Piles	**ton**	**534**

The expected amount of corrosion in the CO_2 injection facilities depend on the quality of the supplied CO_2. The main issue in determination of CO_2 corrosion is the water content in the CO_2. It is safe to assume that CO_2 supplied to the platforms is conditioned in such a way that water drop out is not occurring at the conditions the facilities are operated. If so, the expected corrosion rates are limited and no special material grades or alloys are required and carbon steel can be used. Especially down hole, any mixture of CO_2 and formationwater can result in corrosive fluids. The selection of material used for the wells is outside the scope of thisproject, but it will be crucial in regard to well integrity and project costs. It should be considered that it is verylikely that the existing tubing might have to be replaced before start of injection.

The formation into which the CO_2 is being injected is in the A-20 field. A large storage capacity and excellent reservoir properties alone are not suffcient to make the A-20 field an attractive target for CO_2. storage. Safe storage also requires that a suitable caprock overlies the reservoir. However, there is a lack of experience in building and operating storage systems in this study.

CHAPTER V

ECONOMIC EVALUATION

This chapter describes some key economic concepts and technic to deal with uncertainties that can be applied to help decision.

5.1 Net Present Value (NPV)

The first step in evaluating a project is to create scenario of the baseline situation and calculate the Net Present Value (NPV). The Net Present Value (NPV) is the difference between cash flows (discounted at the average cost of capital) generated by an investment and the initial amount of it. It indicates the net enrichment of the company arising from the implementation of this investment. The term "net" is used to determine the difference between the change in operating cash flows and cash flows of investment. The net present value can be expressed following equation 5.1:

$$NPV=\sum_{t=0}^{N}\frac{CF_t}{(1+i)^t} \tag{5.1}$$

where CF_t represents the cash flows at the end of period t;

i the discount rate

N the number of periods for the life of the investment

A positive Net Present Value means that the investment increases the company's value and that the return is more than sufficient to offset the engaged investment. A negative Net Present Value means that the investment reduces the value of the company, and the productivity is lower than the cost of capital. A positive NPV will lead the acceptance of the project and a negative NPV reject it.

5.2 Sensitivity Analysis

Sensitivity generally refers to the variation in output of a mathematical model with respect to changes in the values of the model's input. A sensitivity analysis attempts to provide a ranking of the model's input assumptions with respect to their contribution to model output variability or uncertainty. The difficulty of a sensitivity analysis increases when the underlying model is non-linear, non-monotonic or when the input parameters range over several orders of magnitude. Many measures of sensitivity have been proposed. For example, the partial rank correlation coefficient and standardized rank regression coefficient have been found to be useful. There are three types of sensitivity analysis classified:

1) Tabulation Basis (Matrix Table)
2) Spider Diagram
3) Tornado Chart

In this case, Tornado chart is selected in order to handling uncertainty outcome from this analysis.

5.3 Monte Carlo Simulation (MCS)

5.3.1 Overview of the simulation

Monte Carlo simulation (MCS) is a preferred approach to the evaluation of the multiple, complex risk factors in the model. Because of the inherent complexity of these risk factors and their interactions, deterministic solutions are not practical, and point forecasts are of limited use and, at worst, are misleading. In contrast, Monte Carlo simulation is ideal for economic evaluations under these circumstances. Domain experts can individually quantify and describe the project risks associated with their areas of expertise without having to define their overall effect on project economics. Most importantly, the resulting predictions of performance do not result in a simple single-point estimate of the profitability of a given oil and gas prospect. Instead, they provide management with a spectrum of possible outcomes and their related probabilities. The idea is, from a simple equation, the model of the project can be used as an equation for the NPV [14].

Figure 5.1 illustrate an overview of the concept of the model. CAPEX, OPEX, CERs, and etc. are developed on a mathematical model and transformed into distribution by commercial software [8]. The objective of the use of simulation in the evaluation of this project is to determine the distribution of the NPV from the variables that affect project performance which is affected its average or the expected Present Value. A mechanism of the simulator is a random number generator that is useful for forecasting, estimation, and risk analysis. The simulation calculates numerous scenarios of a model by repeatedly picking values from a user-predefined probability distribution for the uncertain variables and using those values for the model. As all those scenarios develop associated results in a model, each scenario can have a forecast.

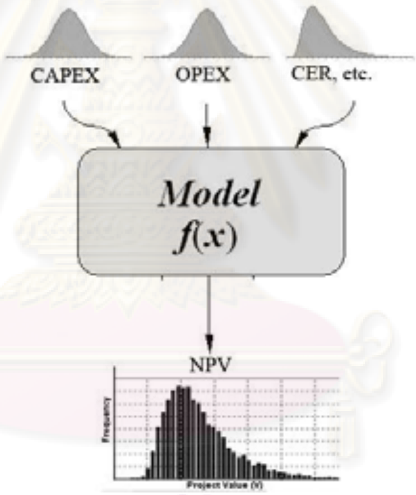


Figure 5.1: Result of the simulation: definition of the distribution of the NPV.

The simulator will perform to assess the effect of Probability Distribution Functions (PDF) and Cumulative Distribution Functions (CDF) of uncertainty input parameters for the models and 5,000 iterations will be performed in this study by using commercial software. Therefore, PDF of NPV for different scenarios will be defined. Each distribution represents the full range of possible values and probabilities of these values. In addition, the mathematical expressions in the Figure 5.2 are provided by software in order to serve statistics view of the forecast (The statistic value in Figure 5.2 is not related to the result of this study).

10,000 Trials   Statistics View   9,761 Displayed

Statistic	Forecast values
Trials	10,000
Mean	$3,775,824
Median	$2,425,951
Mode	---
Standard Deviation	$5,942,930
Variance	$35,318,416,769.8
Skewness	32.20
Kurtosis	1,918.70
Coeff. of Variability	1.57
Minimum	$570,705
Maximum	$392,617,426
Mean Std. Error	$59,429

Figure 5.2: Example for forecast chart statistics

- Trail: also called the number of iterations, n. a trial (or iteration) is a three step process in which the software generates a random number for each assumption cell, recalculates the spread sheet model(s), and collects the result(s) for the forecast scenario(s).

- Mean: is the same as the arithmetic average. It is calculated as:

$$\text{Mean} = \overline{Y} = \frac{1}{n}\sum_{i=1}^{n} y_i \tag{5.2}$$

- Median: is the value in the middle of the distribution.

- Mode: is the single value that occurs most frequently in a set of values.

- Standard Deviation: is a measure of dispersion, or spread, of a distribution. Think of it as roughly equal to the average distance of each value from the mean, although as you can see in the formula below, it is not exactly equal to that:

$$\text{Standard Deviation} = s = \sqrt{\frac{1}{\text{n-1}}\sum_{i=1}^{n}(y_i - \bar{y})^2} \tag{5.3}$$

- Variance: is another measure of dispersion that is equivalent to the standard deviation. Because the variance is equal to the standard deviation squared, it sometimes appears in the statistics view as a very large number. The variance is calculated as:

$$\text{Variance} = s^2 = \frac{1}{\text{n-1}}\sum_{i=1}^{n}(y_i - \bar{y})^2 \tag{5.4}$$

- Skewness: is a measure of asymmetry of a frequency distribution. The formula for skewness used by software is:

$$\text{Skewness} = \frac{1}{n}\sum_{i=1}^{n}\left(\frac{y_i - \bar{y}}{s}\right)^3 \tag{5.5}$$

- Kurtosis: is a measure of peakedness, which is equivalent to measuring tail thickness. The formula for kurtosis used by software is:

$$\text{Kurtosis} = \frac{1}{n}\sum_{i=1}^{n}\left(\frac{y_i - \bar{y}}{S}\right)^4 \tag{5.6}$$

- Coefficient of Variability: also known as the coefficient of variation, is a relative measure of dispersion found as:

$$\text{Coefficient of Variability} = \frac{s}{\bar{y}} \tag{5.7}$$

- Minimum: is the smallest value of all the observed forecast values. Note for models using unbounded-on-the-left stochastic assumptions such as the normal distribution, the more trials that are run, the smaller the minimum is likely to be simply because there are more opportunities for simulator to generate extreme observations.

- Maximum: is the largest value of all the observed forecast values. Note for models using unbounded-on-the-left stochastic assumptions such as the normal distribution, the more trials that are run, the larger the maximum is likely to be simply because there are more opportunities for simulator to generate extreme observations.

- The Range: is the difference between the minimum and the maximum.

- Mean Standard Error: is a measure of precision of the estimate of the mean. The smaller the mean standard error, the greater the precision. From Figure 5.3, this plot shows the standard error of the mean decreases as a function of the number of trials in the simulation. Much of the decrease in standard error is gained after only 2,000 trials.

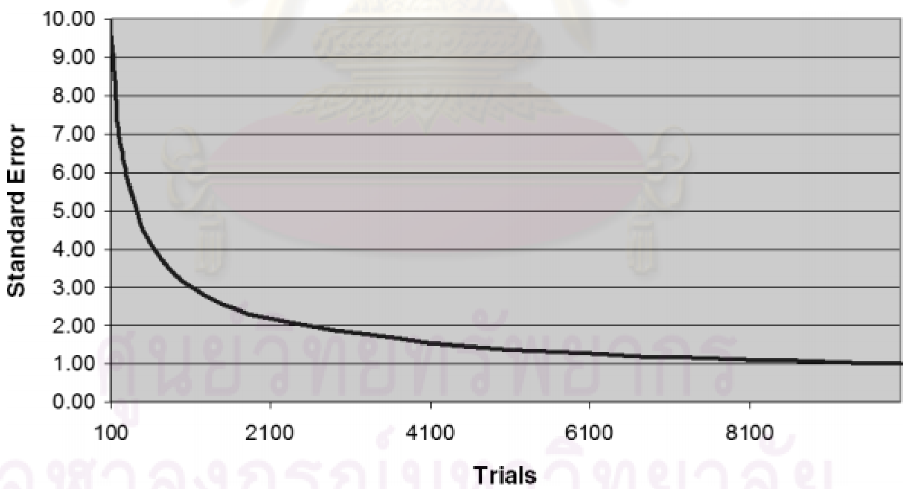


Figure 5.3: Plot of $\frac{1}{\sqrt{n}}$ for n in the interval [100, 100000]

5.3.2 Probability Density Function (PDF)

The PDF is alternatively referred to in the literature as the probability function or the frequency function. For continuous random variables, that is, the random variables which can assume any value within some defined range (either finite or infinite), the probability density function expresses the probability that the random variable falls within some very small interval. For discrete random variables, that is, random variables which can only assume certain isolated or fixed values, the term probability mass function (PMF) is preferred over the term probability density function. PMF expresses the probability that the random variable takes on a specific value.

5.3.3 Cumulative Distribution Function (CDF)

The CDF is alternatively referred to in the literature as the distribution function, cumulative frequency function, or the cumulative probability function. The cumulative distribution function, F(x), expresses the probability the random variable X assumes a value less than or equal to some value x, $F(x) = Prob (X \leq x)$. For continuous random variables, the cumulative distribution function is obtained from the probability density function by integration, or by summation in the case of discrete random variables.

5.4 Cost estimation and economics analysis

The capital cost of project can be divided into capture cost, transportation and storage cost. The CO_2 capture cost is considered part of the capture and compression cost. In this case, platforms have existing membrane capture so the capture cost is not included in the cost estimation. The cost of transportation includes the capital cost for the pipeline and the cost of storage includes the cost of the injection system including the injection wells, drilling and new platform.

5.4.1 Project scenarios

To assess the sensitivity of the model to changes in multiple performance and economic parameters, distributions for each parameter are assessed by using the historical values based on volume of injection and the expert judgments which can be hypothesized that the costs are transformed into many types of distribution (such as a uniform, triangular or lognormal distribution). The distributions allocated to the main variables are followed by sections below:

5.4.2 CCS Project expenditures (Investment costs)

CCS Project expenditures can be classified to

- Capital Expenditure (CAPEX)
  - Construction cost
  - Equipment and facility costs
- Operational Expenditure (OPEX)
  - Ongoing cost for running operations

In additional, the investment costs from others research which are used in this model, are adjusted by 5.5% inflation and convert to US dollar by using currency denomination in January 2011.

5.4.2.1 CAPEX and OPEX of Capture

The main cost driver for the CAPEX of capture is the addition of capture-specific equipment. The technology considered is a membrane removal. However, the membrane removal system has already installed in production platforms so CAPEX and OPEX of capture on the CCS project is not include in this evaluate. In addition, the appropriate metric for operation of capture costs is the cost of CO_2 captured, which ranges from roughly €7 to €45 per tCO_2 [10] depending on plant type and other design and operating factors.

5.4.2.2 CAPEX and OPEX of Compression

After separation, the CO_2 is compressed into liquid for offshore transport. Total operating costs are calculated on basis of the investment costs operation and maintenance costs and electricity costs. The compressor size is required to determine the capital cost of the compressor, while the compressor station annual power requirement is required to calculate operating cost. According to the calculation model in appendix A3, a four-step centrifugal compressor compresses pure CO_2 from approximately 0.1 MPa to 12 MPa requires 420 kJ/kg CO_2 that, for a design capacity of 0.85 million tonnes per year, CO_2 requires an 12,600 kW compressor. As shown in Figure 5.4, compressor capital cost as a function of the compressor power requirement, which is determined from the calculation model. Distribution bounds

25% above and below deterministic value following author's suggestions [18]. The cost of compression can be determined by substitution a value of 12,600 kW in the regression in Equation 5.2

$$\text{Cost (Million \$)} = \text{kW} \times 0.0075 + 0.58 \tag{5.2}$$

where the result is in millions of US dollars, and kW is the compressor design power in kW. This calculation yields a cost of \$95 million US of designed capacity. The capital investment of compression equipment costs are interpolated for power requirement and adjusted by inflation rate following Figure 5.4.

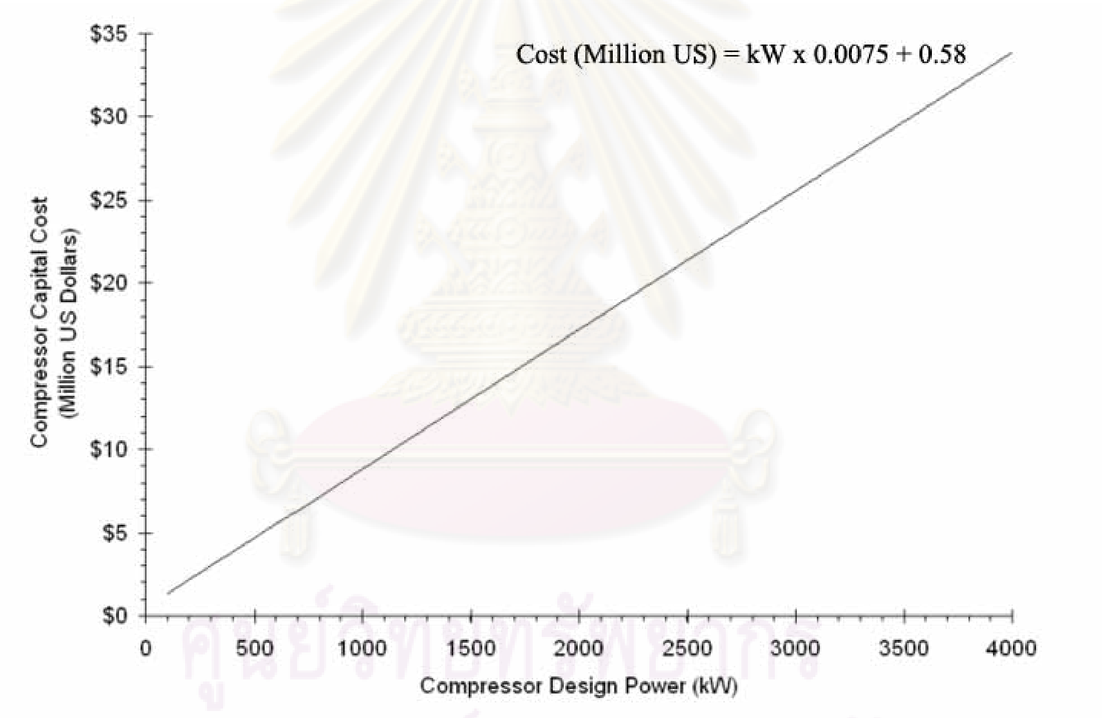


Figure 5.4: The capital cost of compression equipment

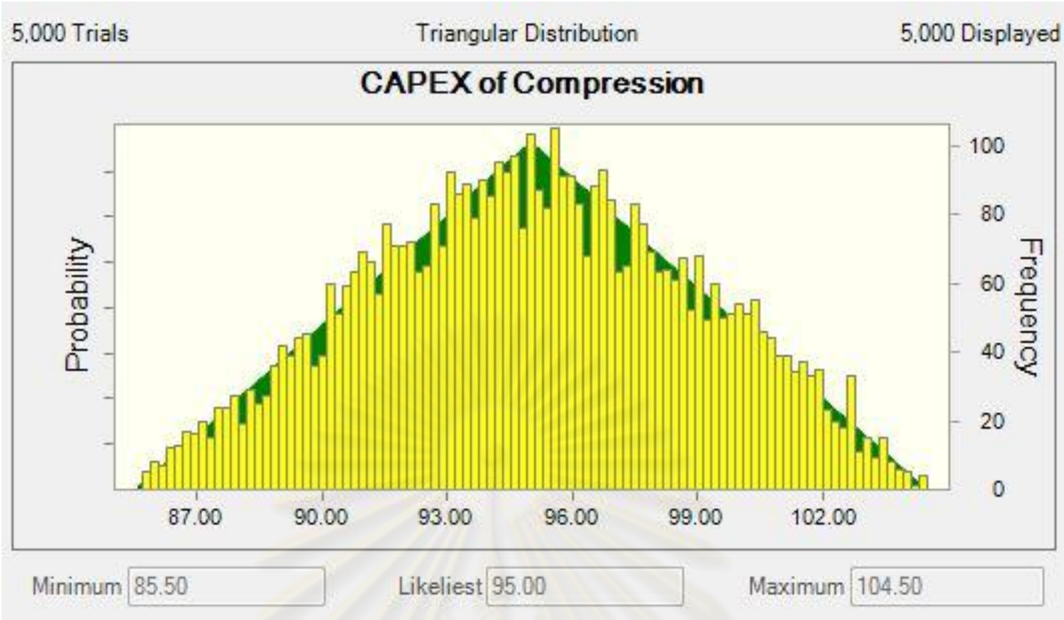


Figure 5.5: CAPEX of compression

According to Appendix A3, operating cost of compression is calculated and provided in uniform distribution as in Figure 5.6. Uniform distributions were selected to represent uncertainty in this case because there is no prior information that would suggest choosing a more complex distribution.

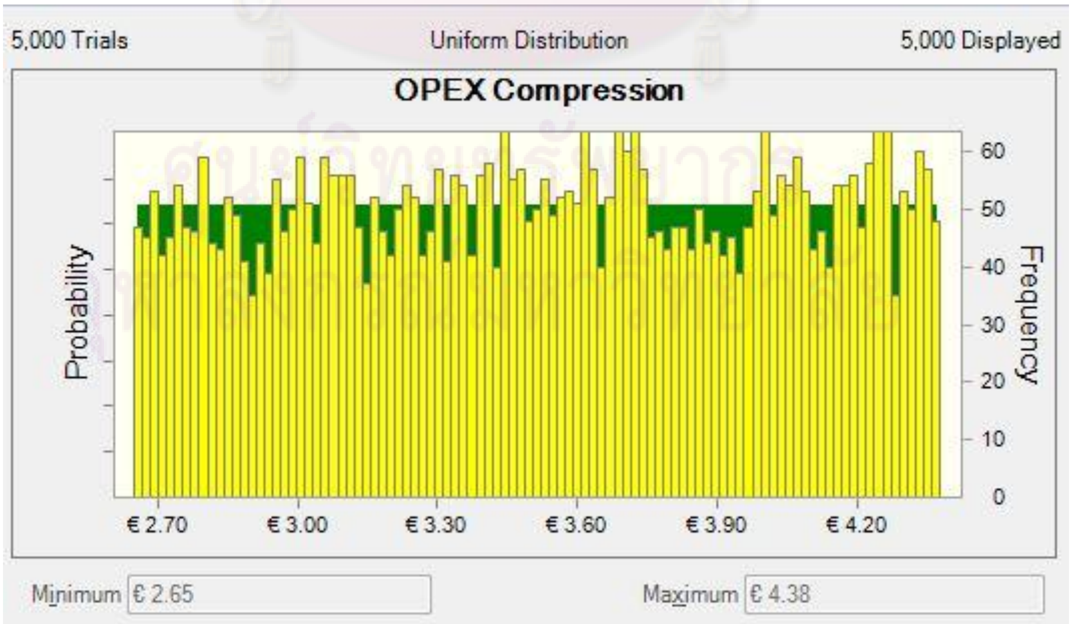


Figure 5.6: OPEX of compression

5.4.3.3 CAPEX and OPEX of Transportation

The CAPEX of the CO_2 pipeline is based on capital cost data for natural gas pipelines contained in Department of Mineral Fuel (DMF). The costs for transport consist of construction costs (material costs, labor, maintenance, assurance, licenses). The costs are depending on flow of the carbon dioxide to be transported.

The construction costs for a pipeline with a diameter of 6 inch are estimated by DMF (2010) at $1.1 million US per km along the distance of 10 km. S.T. McCoy [18] suggests that distribution of CAPEX bounds 25% above and below deterministic value. The cost can be generated to triangular distribution following Figure 5.7.

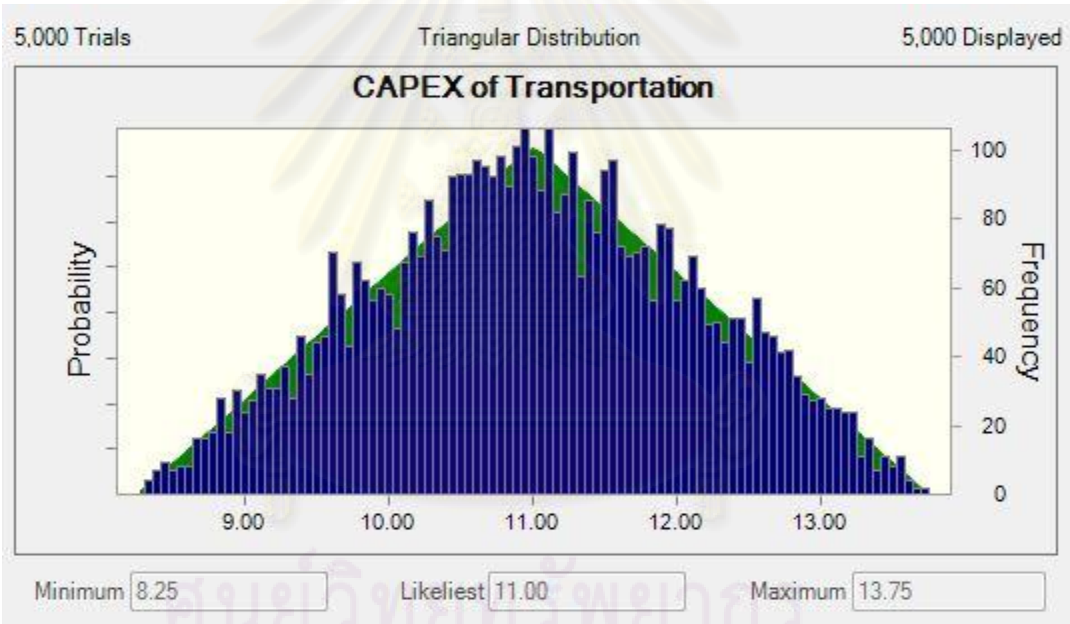


Figure 5.7: CAPEX of transportation

Operation costs of transportation are presented in three sources:

- Hendriks et al. (2004). Pipeline transport costs per 100 km for flow rates of 25 kg/s (high end) and 250 kg/s (low end) and for velocities of 1 m/s (high end) and 3 m/s (high end).
- IPCC (2005). Pipeline transport costs per 250 km for mass flow rates of 5 (high end) to 40 (low end) $MtCO_2$/year.

- IEA (2008). Pipeline transport costs per 100 km. Higher range for mass flow rates of 2 Mt CO_2/yr, lower range for mass flow rates of 10 Mt CO_2/yr.

The relationship between costs and distance of pipeline in three sources are summarized in Table 5.1.

Table 5.1: Pipeline transportation OPEX

Pipeline transportation costs	Ecofys 2004 (€/t CO2) [11]			IPCC 2005 (US$/t CO2) [10]			IEA (2008) (US$/t CO2) [9]		
Distance (km)	Min	Med	Max	Min	Med	Max	Min	Med	Max
100	1	3	6				1	2	3
							2	4	6
250				1	5	8			

The cost of pipeline is used following by first study since the flow rates and velocities are as same as the case study but the transportation in A-20 field requires approximately 10 km so cost of transports are adjusted following Table 5.2 and can be transformed into triangular distribution following Figure 5.8.

Table 5.2: Pipeline transportation costs adjusted distance and inflation

Pipeline transportation costs				Note
Distance (km)	Min	Med	Max	
100	1	3	6	From Ecofys 2004 (€/t CO2) [11]
10	0.14	0.41	0.83	Adjusted distance and inflation (€/t CO2)

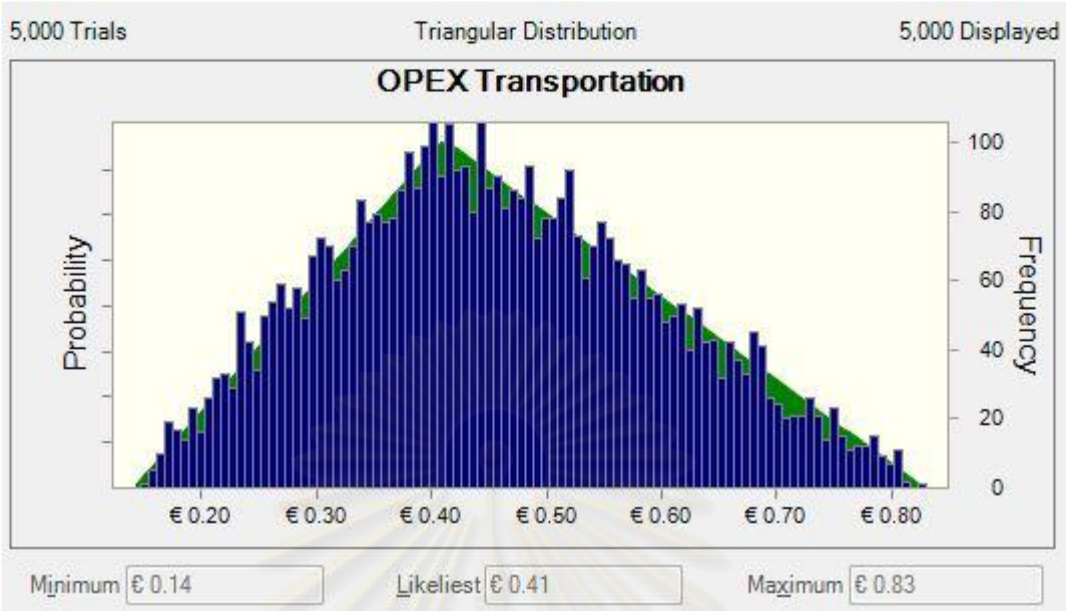


Figure 5.8: OPEX of transportation

5.4.3.4 CAPEX and OPEX of Storage

The costs for injection are mainly costs for new platform, injection wells, and operational costs. Offshore additionally a platform is required for the period of drilling and injection. Drilling costs vary historically with the amount of competing activity at other projects and the availability of drilling rigs, and mainly related to the depth and diameter of the well as well as the properties of the rock formation. The total average cost for drilling a well ranges between $1 million US and $1.5 million US (DMF, 2009). The costs include material costs as casing, cement, materials, supplies, water, and transportation to deliver materials to the drilling site.

The basis for the cost estimate is a compact platform design for accommodation of four injection wells. According to the calculation of injection well in Section 4.4.1, wellhead platform requires 3 wells and a total injection capacity of 0.83 million m^3 of CO_2 per day. Table 5.3 provides capital expenditure of injection platform. The average cost at $96 million US of a CO_2 injection well consists of the cost for drilling, completion, testing and hook up of the well. Drilling and completion (D&C) costs include the cost of physically drilling an injection well, running casing, hanging tubing, and installing any downhole equipment (e.g., chokes and packers).

The distribution of CAPEX bounds 25% [18] above and below deterministic value and can be generated to triangular distribution following Figure 5.9.

Table 5.3: CAPEX for injection platforms (2009) [4]

Four well mono-tower	**CAPEX**	
	Million € (2009)	**Million US$ (2010)**
Construction and drilling	199	261
Wells (3 wells)	90	118
CO_2 injection	-	
Natural gas consumption	-	
New platforms total cost	**289**	**379**
Average cost per injection well	96.33	126.33

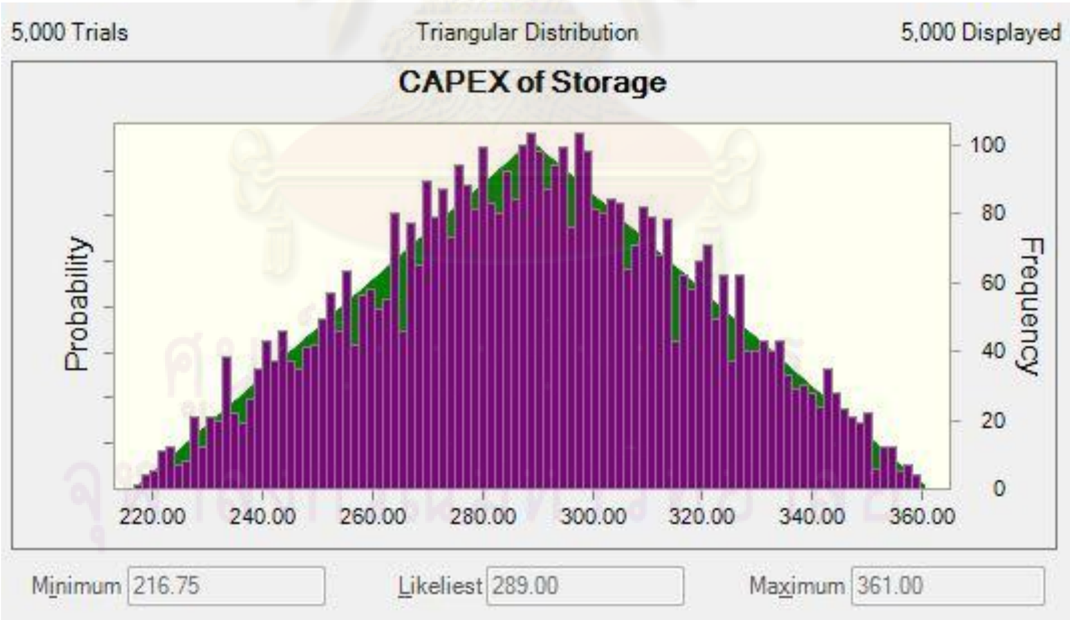


Figure 5.9: CAPEX of storage

In term of OPEX, it includes labor, fuel, and power. Direct overhead charges are also included for operations, such as site preparation, road building, mobilization, and demobilization and hauling costs. Table 5.4 (IPCC 2005) summarizes the CO2 storage OPEX estimates for the United States, Australia and Europe. These estimates include operating and site characterization costs. Monitoring, remediation and other additional costs required to address long-term liabilities have been omitted.

Table 5.4: CO_2 Storage OPEX Estimates by IPCC 2005 [10]

Options			**€/tCO_2**		
Storage type	**On/Offshore**	**Location**	**Low**	**Mid**	**High**
Saline formation	Onshore	Australia	0.2	0.4	4
Saline formation	Onshore	Europe	1.5	2.2	4.9
Saline formation	Onshore	USA	0.3	0.4	3.5
Saline formation	Offshore	Australia	0.4	2.7	23.7
Saline formation	Offshore	N. Sea	3.7	6.0	9.4
Depleted oil field	Onshore	USA	0.4	1.0	1.5
Depleted gas field	**Offshore**	**USA**	**1.3**	**1.4**	**1.8**
Disused oil or gas field	Onshore	Europe	0.9	1.3	3.0
Disused oil or gas field	Offshore	Europe	3.0	4.7	6.4

The annual operating costs of depleted gas field offshore in USA are used and adjusted by inflation rate from 2005 to 2010 as shown in Table 5.5 and transformed into triangular distribution as in Figure 5.10.

Table 5.5: CO_2 Storage OPEX Estimates after adjusted inflation

Options		**€/tCO_2**		
Storage type	**On/Offshore**	**Low**	**Mid**	**High**
Depleted gas field	Offshore	1.70	1.80	2.30

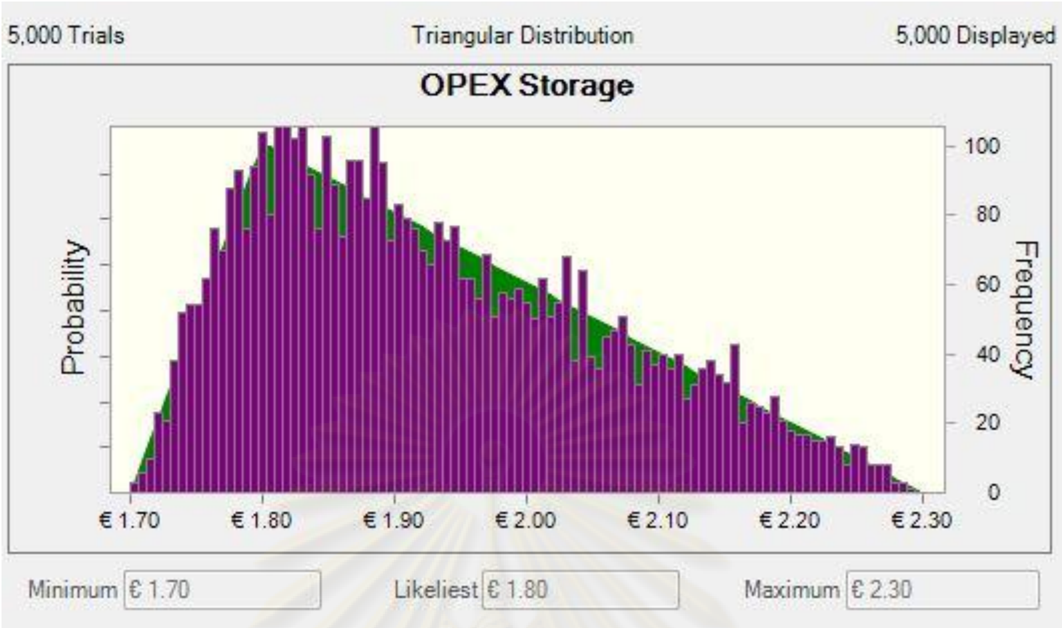


Figure 5.10: OPEX of storage

5.4.3 General assumptions

Beside CAPEX and OPEX, this section is explain about other assumptions that are used in this study which is composed of Carbon credit, Gas and condensate prices, economic discount rate, Fiscal regime and Currency denomination.

5.4.3.1 Carbon credit

Carbon credits and carbon markets are a component of national and international attempts to mitigate the growth in concentrations of greenhouse gases (GHGs). One carbon credit is equal to one ton of carbon dioxide, or in some markets, carbon dioxide equivalent gases. Carbon trading is an application of an emissions trading approach. Greenhouse gas emissions are capped and then markets are used to allocate the emissions among the group of regulated sources.

There are also many companies that sell carbon credits to commercial and individual customers who are interested in lowering their carbon footprint on a voluntary basis. These carbon offsetters purchase the credits from an investment fund or a carbon development company that has aggregated the credits from individual projects. The quality of the credits is based in part on the validation process and sophistication of the fund or development company that acted as the sponsor to the carbon project. This is reflected in their price; voluntary units typically have less value than the units sold through the rigorously validated Clean Development Mechanism. Historical data of carbon credits (Spot price from pointcarbon.com, Apr 2008 – Apr 2010, Appendix B) can be plotted in Figure 5.11.

Figure 5.11: Historical price of CER 2008-2010

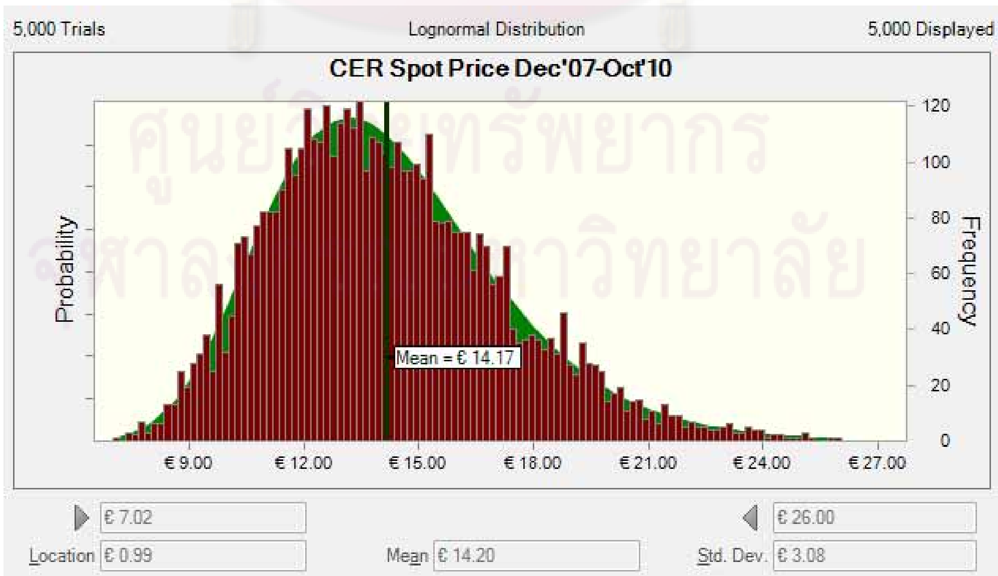


Figure 5.12: Lognomal distribution of Carbon credit price

The price of CER can be transformed and fitted into lognormal distribution shown in Figure 5.12 by the simulator. From the distribution, it provides a value of mean, variance, and standard deviation of carbon price at €14.20, €9.14, and €3.08 per tCO_2 respectively.

5.4.3.2 Gas and condensate prices

For the analysis, natural gas price in contract is $3.23 per million BTU. Due to increasing of oil price in present day, condensate price has been adjusted to $63 per barrel.

5.4.3.3 Economic discount rate

Normally, the economic discount rate is provided by the local planning agency or Ministry of Finance which lies on between 10-12.5 percent. An economic discount rate of 10 percent per year has been used for cash flow calculation.

5.4.3.4 Fiscal regime

In Thailand, tax for E&P Company (concessionaire) shall be levied according to the Petroleum Income Tax Acts (PITA) and Petroleum Acts (PA). Currently, concessions can essentially be taxed under two different Regimes, as very briefly summarized in Table 5.6 and Thailand I is taken into account for the study.

Table 5.6: Thailand Fiscal Regime

Payment	Thailand I	Thailand III
Royalty	12.5%	5-15%
Petroleum Taxes	50%	50%
SRB	-	0-75%

5.4.3.4 Currency denomination

All calculations have been made in U.S. dollars, which the currency exchange rate from EURO to US dollar is 1.312 (January 2011)

5.4.5 Economic Model

Discounted cash flow (DCF) model is applied to consider economic benefits of carbon capture and storage. DCF method uses the concepts of the time value of money which is mainly used for investment decisions and sensitivity analysis of the project and the modeling is based on real data of the case study field. Table 5.7 presents the economic parameters and values which are applied for running in the model and the assumptions used to estimate the cash.

Table 5.7: Main economic assumptions

Discounted rate	10%
Inflation rate	5.5%
Life of projects	33 years (2007-2039)
Depreciation method	Sum of year digit
Concessionaire	THAI I
Royalty	12.5%
Petroleum taxes	50%
Gas price	$3.23 per million BTU
Condensate price	$63 per BBL
Carbon credit period	7, 10, and 21 years

Cash flow calculation

Gross revenue = Total gas and condensate revenues

Net revenues = Gross revenues – Royalties

Royalties = Gross revenue x Royalty

Income Tax = (Gross revenue – Royalties – CAPEX – OPEX – Depreciation) x Petroleum tax

Net Cash Flow = Gross revenue – Royalties – CAPEX – OPEX – Taxes

Example of cash flow calculation is expressed in Table C1 (Appendix C) by using the above model and summary of the calculation is shown in Table C2 (Appendix C). However, the cash flow in the Tables is used for performing the simulation. Each of variable and parameter which are used in model are defined in section 5.4.2. Simulator will generate random numbers and variants during the simulation process so the numbers in the Tables C1 and C2 do not represent the results of the actual simulation.

CHAPTER VI

RESULTS AND DISCUSSIONS

This chapter provides result obtained from an analytical of the model. The results are shown in Probability Distribution Functions (PDF) and Cumulative Distribution Functions (CDF) as well as the Interest Rate Return (IRR) and Sensitivity Analysis (SA) expressed by using commercial software to perform Monte Carlo simulation.

6.1 Base case scenario

NPV and IRR are commonly used for evaluating and reflecting the value of an investment. Higher NPV and IRR are better for value of business. The result of base case indicates that the project is economically feasible to invest.

The probability of occurrence can be examined. The model of gas field "A-20" represents normal distribution. The simulation was run with 5,000 trials to forecast NPV, which provided a mean NPV $297.64 million US with 95 percent confidence and a standard deviation of $54.57 million US. Revenues come from gas sale and condensate sale for 33 years which consist of natural gas production of 3,333 Bcf and condensate of 45.5 million bbl. The simulator provides distribution as in Figure 6.1. In addition, IRR is computed and it shows 18% in this case.

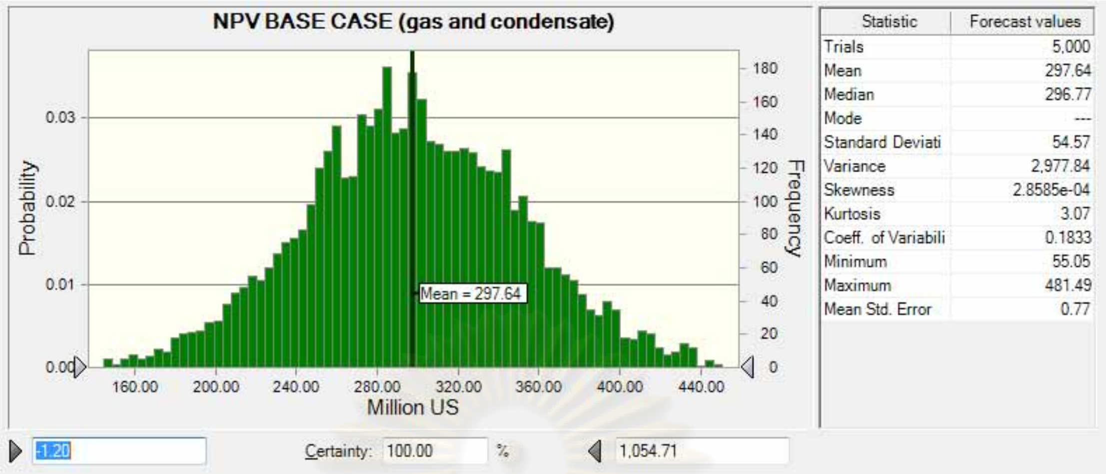


Figure 6.1: CDF of NPV base case

6.2 CCS Scenarios

In this section, an additional constraint is integrated in the model. A situation is simulated that the company installs CCS system. The scenarios compose 4 sections which are the scenario that the project has no carbon credit and can obtain carbon credit in different periods.

For including CDM in CCS, CDM projects can have 7 years crediting period that may be renewed twice, making a total of 21 years or a once-off 10 years crediting period. So, three scenarios are considered for evaluating how carbon credit can offset the investment cost of CCS.

6.2.1 Install CCS without CERs

It is clearly seen that the costs of CCS project lead to negative of overall NPV. However, there is a small but significant portion of project outcomes that could still gain money for the company. From this information, it can be concluded that there is a 35.39 percent chance that this project will have a positive NPV as following in Figure 6.2. It is apparently not good enough for a project of this sort to avoid a negative NPV.

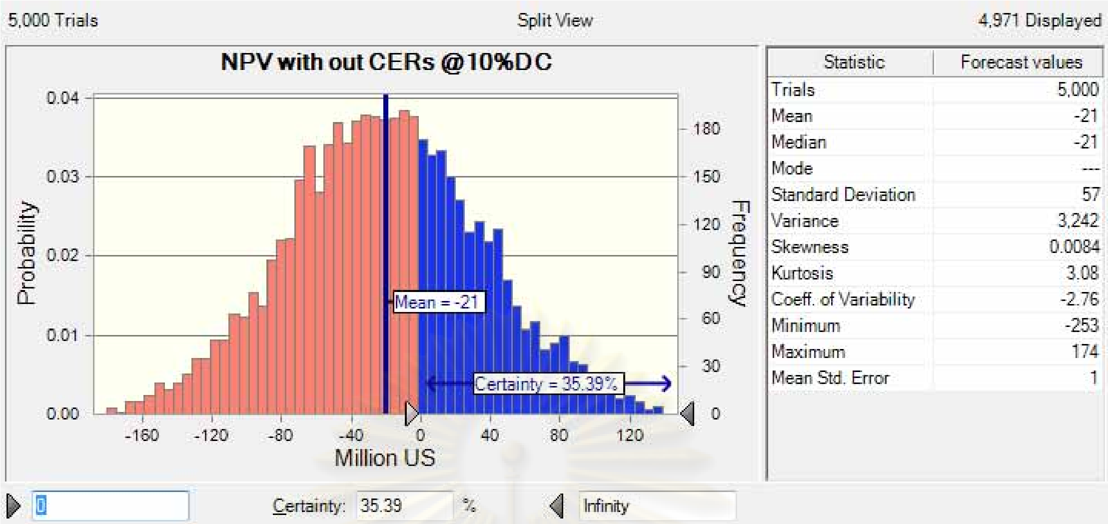


Figure 6.2: CDF of NPV without carbon credit

6.2.2 CCS with Carbon credit for 7 years

For NPV including CERs, the large peak of NPV decreases to $69 million with the minimum credit period of 7 years and the forecast distribution of outcomes for the chance of getting positive NPV increase from 35.39% to 81.49% as shown in Figure 6.3. It can be seen that there are not enough carbon credits to offset the cost of CCS in this case.

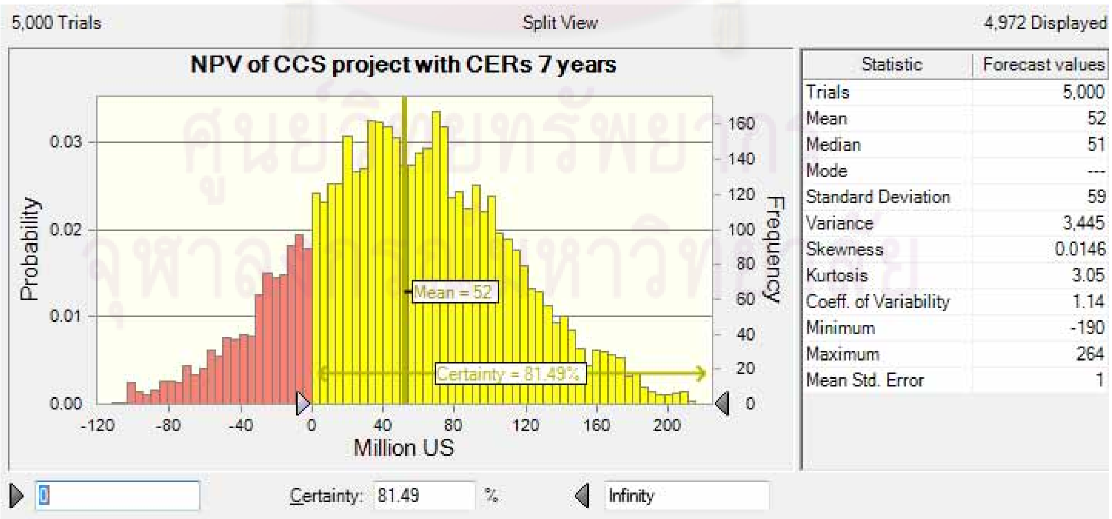


Figure 6.3: CDF of NPV with CERs 10 years

6.2.3 CCS with Carbon credit for 10 years

The reduction in credit period of 10 years leads to an increase about $34 million US of the NPV due to gaining of income from selling carbon credit. Consequently, the chance of getting positive NPV increase to 88.21% followed in Figure 6.4. In this case, carbon credits can be offset the CCS cost but they are still not enough for cover the CCS investment.

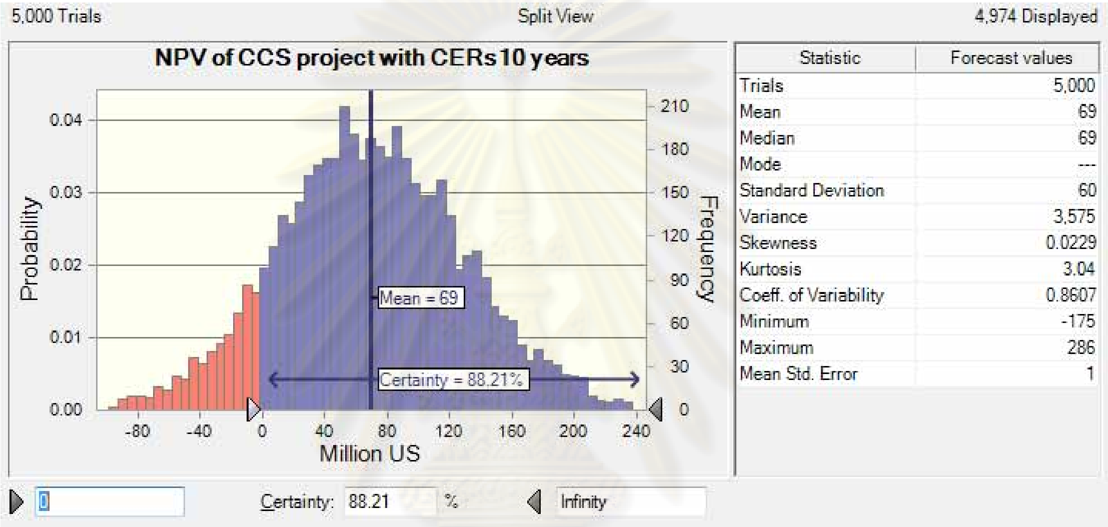


Figure 6.4: CDF of NPV with CERs 10 years

6.2.4 CCS with Carbon credit for 21 years

Including CER for 21 years, it can be seen that the NPV in this case rises higher than NPV in the previous cases and it can obtains $103 million US. The large peaks lie at around $100 million US, where in fact the NPV of the outcome has a chance at 95.14% that this case will have a positive NPV as in Figure 6.5. Whilst, the project obtains the longest credit period, but not enough to maintain the base case NPV.

However, these outcomes imply that the more credit period leads to the larger NPV and higher risk to get positive NPV. In addition, renewable credit requires registration cost which is around $200,000 however this cost has only small effect in overall cost compare to income form carbon credit.

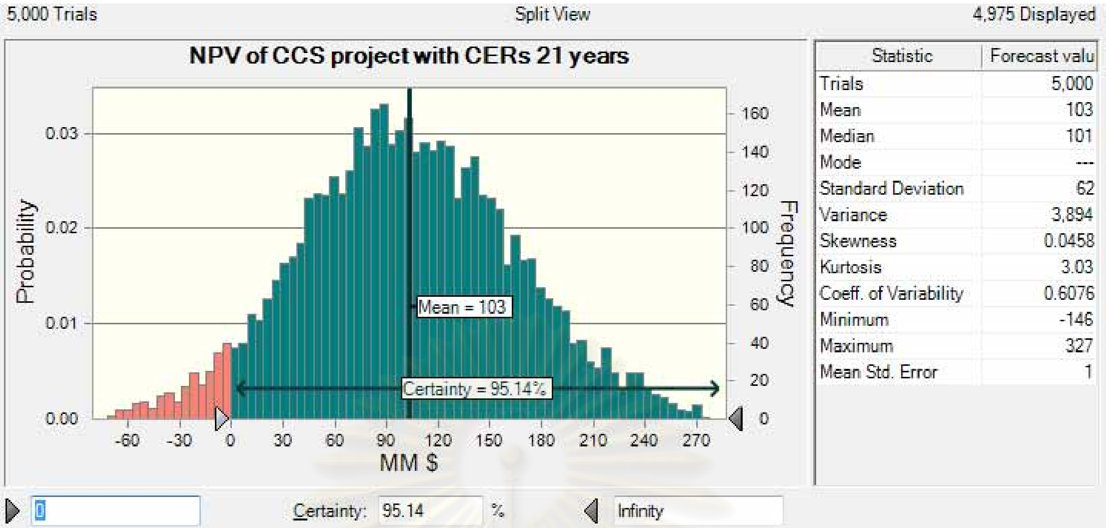


Figure 6.5: CDF of NPV with CERs 21 years

The results for all scenarios are summarized. In general, the comparison between the project “with” and “without” CERs expresses that without income from CERs the project will not economic by itself as the NPV becomes negative (-\$20.62 Million US). In contrast, higher income of carbon credit is the main reason for positive net present value of the project as presented in Figure 6.6.

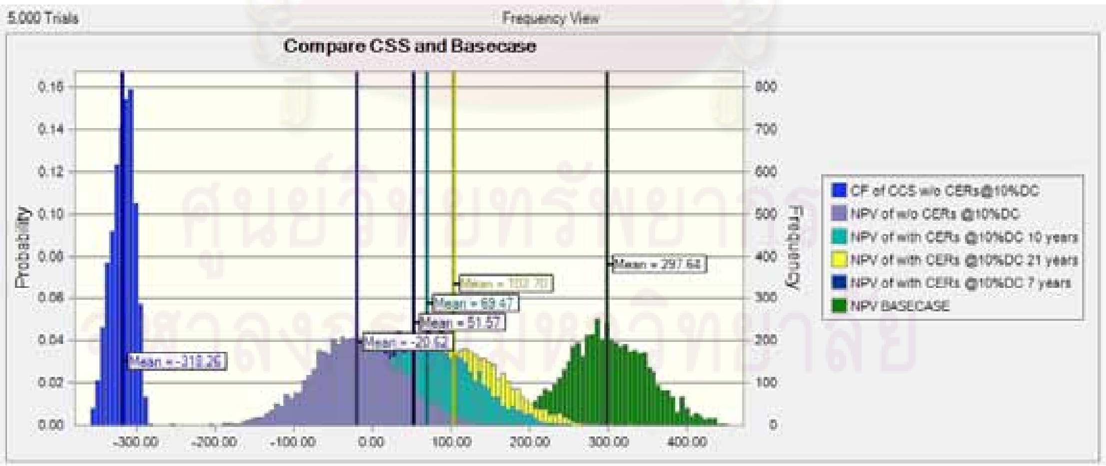


Figure 6.6: Compare all cases (from section 6.2.1-6.2.4)

6.3 Adjust gas price and CER

The current CCS project itself cannot induce the company to invest so CERs and gas price are adjusted which would be incentive for investor. An exploratory economic analysis based upon the existing simulation model. The simulator was performed to establish how much price might be needed to adjust in order to remain NPV as same as the base case.

6.3.1 Result of adjust gas price (without CER)

If the company wants to maintain the NPV at $297.64 million US which equal to the base case, they would consider increasing the gas price about 25% which mean that the price will be rose from $3.23 to $4.04 per million BTU. Table 6.1 provides NPV result that obtains from adjusted the gas price.

Table 6.1 Gas price and NPV of CCS (without CER)

Gas price ($/Mlillion BTU)	NPV of CCS project
Base case = 3.23 (0%)	-$22 Million US
3.50 (8.35%)	$85 Million US
4.04 (25.07%)	**$297 Million US**
4.50 (39.31%)	$481 Million US

6.3.2 Result of adjusted gas price (with CER)

Under different gas price scenario, it can be clearly seen that the gas price at $3.23 per million BTU cannot maintain NPV of base case although the project can gain CERs. For 7 and 10 years credit period, the company has to increase gas price about 19% and 17.95% respectively in order to hold the NPV at $297 million. In 21 years crediting period, there is increasing in gas price at 15.17% for maintain the NPV at $297 million which is the minimum increase value. The Table 6.2 shows how gas price in 7, 10 and 21 years crediting effect to NPV.

Table 6.2 Gas price and NPV of CCS (with CER)

	NPV with Carbon Credit		
Adjusted Gas price ($/Million BTU)	CERs 21 yrs	CERs 10 yrs	CERs 7 yrs
Base case = 3.23 (0%)	102	69	51

3.72 (15.17%)	**297**	263	246
3.81 (17.95%)	332	**297**	281
3.85 (19.19%)	348	315	**297**

6.3.2 Result of adjusting CER price

CER prices are adjusted in order to meet the base case NPV. According to the simulation, it indicates that the 21 years-credit should be rose from €14.2 to €36.5 per tCO_2 which is 57% increasing. For minimum crediting period, the price (€61.6 per tCO_2) increases almost four times more than CERs price from the distribution (€14.2 per tCO_2)

Table 6.3 Adjusted CERs price

NPV of CCS project ($ Million US)	Adjusted CERs (€ per tCO_2)		
	CERs 21 yrs	CERs 10 yrs	CERs 7 yrs
297	36.5	49.5	61.6

6.4 Sensitivity Analysis (SA)

The overall cost of new CCS project follows a normal distribution with a mean of -$318 million US. The simulator provides function to explore the sensitivity of the project outcomes to the risks and assumptions. Figure 6.7 shows a sensitivity analysis of the NPV of CCS to the assumptions made in the model. This chart shows the correlation coefficient of the top 8 model assumptions to the CCS cost forecast in order of decreasing correlation.

At this point, the project manager is empowered to focus resources on the issues that will have an impact on the profitability of this project. Given the information from Figure 6.7, the following actions can be hypothesized to address the top risks in this project in order of importance.

In general, the sensitivity of the project shows that NPV of CCS. Sensitivity of CAPEX of storage shows -91.5% which is a driving influence on value of this project. Using new platform has a direct effect on the construction cost. Secondly, it is very sensitive to changes in the annual operating cost of compression with a contribution to outstanding of the variance of -6.0% because it is a process that takes a lot of energy. The result from CAPEX and OPEX of transportation has a small effect to the overall cost, because the A-20 field has short-distance transport of CO_2.

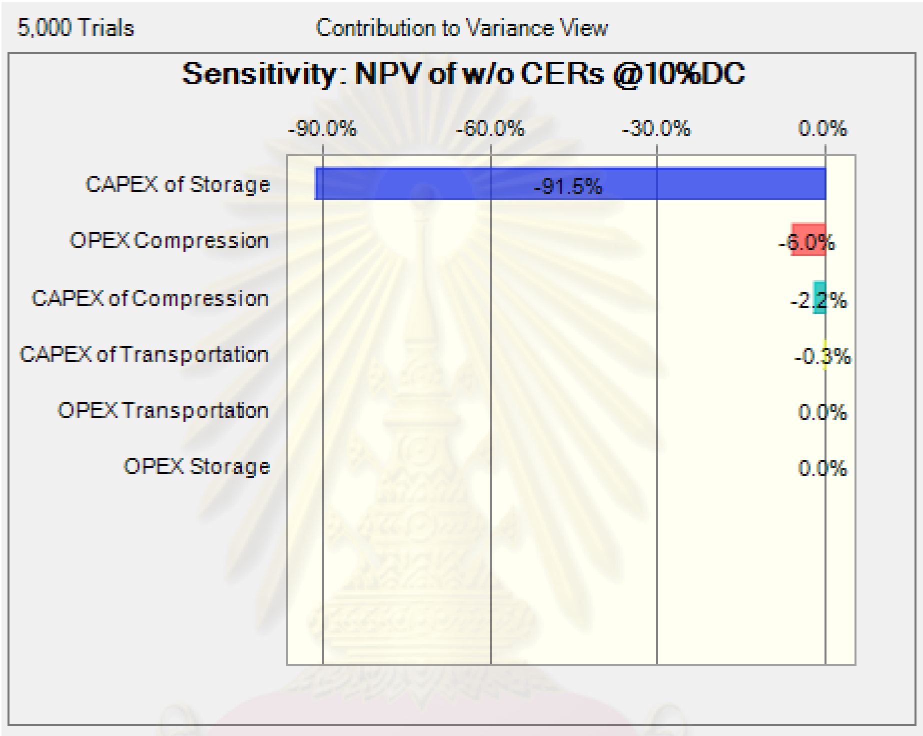


Figure 6.7: Sensitivity of CCS cost and CER price

6.5 Overall of CCS cost

From preliminary cost estimation, the overall CCS project follows a normal distribution with a mean of $318.26 million US or $41.19 per tCO_2 storage. Cost of installing new platform becomes mainly part of the overall cost comparing to other composition of CCS. The study from T.N. Vermeulen [4] showing that using modified platform would be a favor option for optimization the construction cost. The cost distribution is illustrated in Figure 6.8.

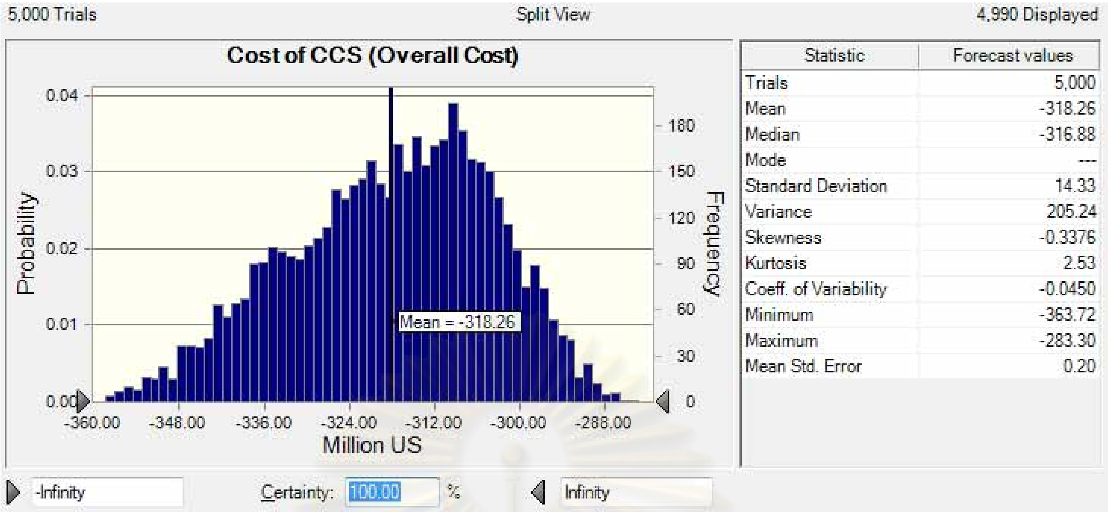


Figure 6.8: Overall of CCS cost

The cost of CCS can be equivalent into cost per tCO_2.The distribution provide mean of \$44.41/tCO_2 (€33.85 per tCO_2) where range of general CCS cost per tCO_2 are between €25 - €60/tCO_2 [14] which varies greatly among projects, and differs depending on the size, scope, and the location of the projects. The cost per tCO_2 is provided following in Figure 6.9.

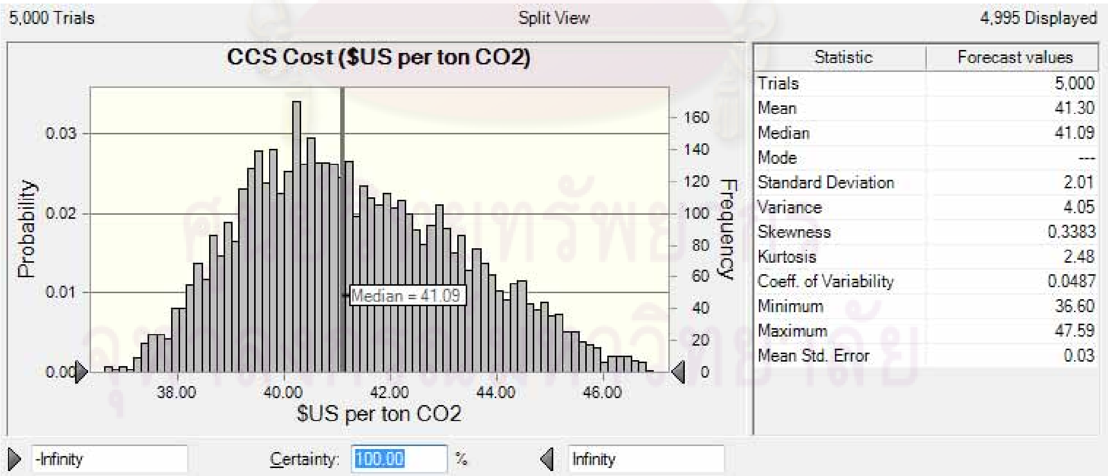


Figure 6.9: CCS cost per tCO_2

Consider between CERs and CCS cost per tCO_2, both of them are additional income and outcome of the project. It is simply indicator of financial of the project. Higher CCS cost per tCO_2 more than CERs means the project will have less NPV than the base case. In other hand, the project will have NPV higher than the base case if CERs is higher than CCS cost as well.

CHAPTER VII

CONCLUSIONS AND RECOMMENDATIONS

This chapter presents the conclusions of the research under the assumption and data in particular scenarios based on the result of research as well as the recommendations of this study and future works.

7.1 Conclusions

The objective of this study was to provide pre-feasibility study of CCS technologies for the offshore case study. Conclusions from this study include the following:

- From the study, the project itself cannot achieve in CCS technology without carbon credit support. Nevertheless, the current price of carbon credit cannot induce the company to invest as well. According to this study, there is a dramatic decrease in NPV for investment of the CCS. The tax subsidies can be a positive mechanism to stimulate private investments. The government can support by providing tax credits, altering the tax rate or a fiscal regime for the CCS project. On the other hand, any gas price adjustment can be incentives for investors to earn a reasonable return.
- The CCS project able to achieve significant reduction in GHG emissions approximately 850,000 tons per year which provide benefits for company in terms of social responsibility and environment.
- The inclusion of CCS projects in the CDM would provide an important incentive for potential investment in project. This incentive could offset the incremental cost of the technology and provide markets with improved investment certainty, which would aid business planning for investment in long-lived and generally large-scale CCS projects.

7.2 Recommendations

As a recommendation for further study on this subject

1. For further study of geological storage, there is a lack of information of CO_2 storage in this study. In order to perform more accuracy estimation, the CO_2 storage needs to undertake more-detailed studies to model character of the reservoir and identify storage capacity.
2. There is uncertainty in CCS costs, which stems from the lack of experience in constructing and operating components of CCS, the range of technology options that can be used, and the assumption, rather than the calculation, for the costs of the transport and storage of CO_2 when the location of the storage site is not known. The cost estimations have been estimated using reference values for the cost of the CO_2 capture, compression, transport and storage based on the literature sources and limited data are available. In order to maximize accuracy and national applicability of the cost estimate, it is recommended discussed in more detailed analysis for particular case.
3. Currently, Thailand does not put a tax on release of CO_2 but if somehow the CO_2 emissions tax is including in law or government policy, the government have to consider for the incentive of CCS investment. According to this study, there was a dramatic decrease in NPV for investment of the CCS. It is recommended performing to establish how much and what type of appropriate economic incentives (e.g. Carbon credit, tax subsidies, fiscal regime) might be needed to support CCS project in Thailand. On the other hand, any gas price adjustment can be incentives for investors to earn a reasonable return.

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APPENDICES

APPENDIX A

A1. Calculation for Volume of Emissions

A-20 gas field produce CO_2 from 2 CPPs. Natural gas from CPP1 and CPP2 comprise the CO_2 content in different portion. Twenty three percent of CO_2 sale specification requires removing the CO_2 before transfer to pipe sale. This section is going to provide a calculation of permeate gas in both platforms. Equation A1 provides feed gas calculation is following as;

$$\text{feed gas} = \text{DCQ} \times \frac{1\text{-}CO_2\text{sale}}{1\text{-}CO_2\text{feed}} \times \frac{1}{1\text{-}0.07} \tag{A1}$$

(0.07 is 7 % of hydrocarbon is used in flaring process)

Where DCQ = Daily Contact Quantity

CO_2 sale = percent of CO2 sale specification

CO_2feed = percent of CO2 from natural gas

- CO_2 in CPP1 = 32% and DCQ = 150 MMscf per day.

$$\text{feed gas} = 150 \times \frac{1\text{-}0.23}{1\text{-}0.32} \times \frac{1}{0.93}$$
$$= 182.6 \text{ MMscf}$$

- CO_2 in CPP2 = 25% and DCQ = 150 MMscf per day.

$$\text{feed gas} = 150 \times \frac{1\text{-}0.23}{1\text{-}0.25} \times \frac{1}{0.93}$$
$$= 165.6 \text{ MMscf}$$

Hence, volume of natural gas feed is 182.6 + 165.6 = 348.2 MMscf ~ 350 MMscf.

$$\text{Permeate gas} = \text{Total Gas feed - DCQ in CPP1 and CPP2}$$
$$= 350 - (150 + 150)$$
$$= 50 \text{ MMscf per day}$$

- Calculation for Combustion Emissions from a Gas Flare

Table A1: Permeate composition

Composition	**% by mole**
CO_2	68.01
N_2	0.78
C_1	26.05
C_2	2.28
C_3	1.95
C_4	0.78
C_{5+}	0.16
Total	**100.0**

- Example of calculation for the year 2009-2027

For CO_2 emissions are based on the generally accepted 98% combustion efficiency to convert from flare gas carbon to CO_2. Valuable hydrocarbons are usually being flared continuously for safety reason, also called as technical flaring which was 50,000,000 scf per day.

Volume of CO_2 emission =

$$\frac{50{,}000{,}000 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{year}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times$$

$$\left(\begin{array}{l} \dfrac{0.8913 \text{ lbmole } CH_4}{\text{lbmole gas}} \times \dfrac{\text{lbmole C}}{\text{lbmole } CH_4} \\ + \dfrac{0.0506 \text{ lbmole } C_2H_6}{\text{lbmole gas}} \times \dfrac{2 \text{ lbmole C}}{\text{lbmole } C_2H_6} \\ + \dfrac{0.0348 \text{ lbmole } C_3H_8}{\text{lbmole gas}} \times \dfrac{3 \text{ lbmole C}}{\text{lbmole } C_3H_8} \\ + \dfrac{0.0078 \text{ lbmole } C_4H_{10}}{\text{lbmole gas}} \times \dfrac{4 \text{ lbmole C}}{\text{lbmole } C_4H_{10}} \\ + \dfrac{0.0122 \text{ lbmole } C_5\text{plus}}{\text{lbmole gas}} \times \dfrac{5 \text{ lbmole C}}{\text{lbmole } C_5\text{plus}} \end{array} \right)$$

$$\times \frac{0.98 \text{ lbmole } CO_2 \text{ formed}}{\text{lb mole C combusted}} \times \frac{44 \text{ lb CO2}}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

Substitute the permeate composition (C_1-C_{5+}) from Table A1 into the above equation. CO_2 emission equals to 830,000 tons per year.

A2. Calculation for Gas Flow Rate and Pipe Diameter

The operating pressure and temperature lies in between 8.6 MPa at 4°C and 15.3 MPa at 38°C. The upper and lower limits are set, respectively, by the ASME-ANSI 900# flange rating and ambient condition coupled with the phase behavior of CO_2. This section shows sample of calculation of gas flow rate and pipeline diameter.

- Calculation of Flow rate
    - CO_2 830,000 ton per year with density of 0.700 g/mL at liquid phase
    - Assuming gas velocity in pipeline is 2 m/s

$$\text{Flow rate} = \frac{830{,}000\ \text{ton}}{\text{year}}\left(\frac{\text{cubic meter}}{0.7\ \text{ton}}\right)\times\frac{\text{year}}{365\ \text{days}}\times\frac{\text{day}}{24\ \text{hours}}\times\frac{\text{hour}}{3{,}600}$$

$$= 0.037\ \text{m}^3/\text{s} = 25.9\ \text{kg/s (use 30 kg/s)}$$

A3. Calculation for size of CO_2 compressor

Table A2 gives the main characteristics of compressors pressurizing from 0.1 to 12 MPa (1 bar to 120 bars) for a compressor with a capacity of 30 kg/s. The compressor size is required to determine the capital cost of the compressor, while the compressor station annual power requirement is required to calculate operating cost. The electricity consumption is calculated according to Equation A2 [11]. Constants are based on figures in Table A2.

Table A2: Operational conditions for compression with a capacity of 30 kg/s.

	1st stage	2nd stage	3rd stage	4th stage
Inlet/outlet pressure (bars)	1/3.8	3.8/10.3	10.2/38.3	120
Inlet/outlet temperature (°C)	30/155	35/128	35/165	35/152
Polytropic efficiency	85.4	84.7	83.6	76.8
Compression energy	420 (kJ/kg CO_2)			

$$E = C_{el}\times\ln\left(\frac{P_{outlet}}{P_{inlet}}\right)\times F \qquad \text{(A2)}$$

With:

E = Electricity use (kJe/s)

P_{outlet} = Outlet pressure (Pa)

P_{inlet} = Inlet pressure (Pa)

C_{el} = Constant (87.85 kJe/kg)

F = CO_2 flow (kg/s)

So, Compression energy = 420 kJ/kg CO_2

CO_2 flow rate 30 kg/s = 30x3600 kg/hr = 108,000 kg/hr

$$\text{Design power} = \frac{420\text{ kJ}}{\text{kg CO}_2} \times \frac{108{,}000\text{ kg}}{\text{hr}} \times \frac{\text{kW hr}}{3600\text{ kJ}}$$
$$= 12{,}600\text{ kW}$$

- Calculation OPEX of compression

For calculation operating costs of compressor, the electricity consumption is calculated and total operating costs are calculated on basis electricity costs (0.03 €/kWh).

$$\text{Total cost} = \left(\frac{420\text{ kJ}}{\text{kg CO}_2}\right) \times \left(\frac{277\text{x}10^{-6}\text{ kWh}}{\text{kJ}}\right) \times \left(\frac{0.03\text{ EU}}{\text{kWh}}\right) \times \left(\frac{1000\text{ kg CO}_2}{\text{tCO}_2}\right)$$
$$= \frac{3.5\text{ EURO}}{\text{tCO}_2}$$

A4: Calculation of pipe diameter

$$\text{Pipe Diameter} = \sqrt{\frac{4 \times \text{flow rate}}{\pi \times \text{velocity}}}$$
$$= \sqrt{\frac{4 \times 0.037\text{ m}^3/s}{\pi \times 2\text{ m/s}}}$$
$$= 0.153\text{ meters}$$
$$= 6.04\text{ inches}$$

So, 6 inches pipeline diameter is used for the handle the flow rate.

A5. Calculation for number of well

An estimation of the preliminary flow rate [16] can be estimated by Equation A3,

$$q = \frac{\rho_r}{\rho_s} \times \frac{2\pi kh}{\ln \frac{r_e}{r_w} \mu} \times \Delta P \qquad \text{(A3)}$$

where q = flow rate (m^3/s)

ρr = density of the gas under reservoir conditions (700 kg/m^3)

ρ_s = density of the gas under standard conditions (1.95 kg/m^3)

k = permeability of the reservoir ($25x10^{-15}$ m^2: 1 md = $9.87x10^{-13}$ m^2)

h = thickness of the reservoir (10 m)

r_w = radius of the well (m)

r_e = radius of the influence sphere of the injection well (m)

μ = viscosity of CO_2 at the well bottom ($2x10^{-5}$ Pas)

ΔP = pressure difference between reservoir and well bottom pressure (1.71×10^6 Pa)

As a rule of thumb, the value of the logarithmic term can be assumed as 7.5 [17]. The approximate injection capacity per injection well, identified by this simple model is 1,090 ton per day. So, a set of 3 injection wells will be sufficient to sequester 830,000 tons per year or 2,800 ton per day emissions from the field. The flow rate calculated by this equation only gives an indication of the injection rate and deviation may occur in a practical situation.

APPENDIX B

The historical prices of CERs are expressed in the appendix.

Table B1: Carbon credit spot price from April 2008 to April 2010

Date 2008	Price (€ per tCO2)	Date 2009	Price (€ per tCO2)	Date 2010	Price (€ per tCO2)
Apr-08	15.01	Jan-09	13.08	Jan-10	11.87
Apr-08	15.48	Jan-09	13.17	Jan-10	11.65
Apr-08	15.57	Jan-09	13.39	Jan-10	12.02
Apr-08	15.29	Jan-09	12.7	Jan-10	11.95
Apr-08	15.59	Jan-09	12.4	Jan-10	11.99
Apr-08	15.62	Jan-09	11	Jan-10	11.96
Apr-08	15.72	Jan-09	9.38	Jan-10	11.37
Apr-08	15.61	Jan-09	10.23	Feb-10	11.5
Apr-08	15.71	Jan-09	10.21	Feb-10	11.64
May-08	15.96	Jan-09	10.19	Feb-10	11.81
May-08	16.19	Feb-09	9.65	Feb-10	11.88
May-08	16.27	Feb-09	9.38	Feb-10	11.72
May-08	17.41	Feb-09	9.15	Feb-10	11.66
May-08	17.24	Feb-09	7.77	Feb-10	11.65
May-08	17.41	Feb-09	7.6	Feb-10	11.5
May-08	17.43	Feb-09	7.6	Mar-10	11.3
Jun-08	17.45	Feb-09	9.45	Mar-10	11.4
Jun-08	18.18	Feb-09	8.4	Mar-10	12.05
Jun-08	19.02	Mar-09	9.2	Mar-10	11.5
Jun-08	19.15	Mar-09	9.13	Mar-10	11.56
Jun-08	19.97	Mar-09	10.41	Mar-10	11.62
Jun-08	20.09	Mar-09	10.31	Apr-10	11.65
Jun-08	19.99	Mar-09	10.3	Apr-10	12.2
Jun-08	19.93	Mar-09	11.4	Apr-10	12.7
Jun-08	20.3	Mar-09	10.83	Apr-10	13.31
Jun-08	20.4	Mar-09	10.12		
Jul-08	21.4	Apr-09	9.8		
Jul-08	22.25	Apr-09	10.18		
Jul-08	21.25	Apr-09	10.64		
Jul-08	21.1	Apr-09	10.3		
Jul-08	22.3	Apr-09	10.45		
Jul-08	19.8	Apr-09	10.73		
Jul-08	19.2	Apr-09	10.8		
Jul-08	18.95	Apr-09	10.6		
Jul-08	17.95	Apr-09	10.52		
Jul-08	17.85	Apr-09	11.17		
Aug-08	16.7	Apr-09	11.22		
Aug-08	17.6	May-09	11.37		
Aug-08	18.9	May-09	11.25		
Aug-08	19	May-09	11.67		

Aug-08	19.95	May-09	12.17
Aug-08	19.1	May-09	12
Aug-08	19.9	May-09	11.71
Aug-08	20.15	May-09	12.31
Aug-08	19.95	May-09	12
Sep-08	20.55	Jun-09	12.68
Sep-08	20.1	Jun-09	12.7
Sep-08	20.1	Jun-09	12.12
Sep-08	18.6	Jun-09	11.35
Sep-08	18.85	Jun-09	11.38
Sep-08	18.6	Jul-09	11.7
Sep-08	18.8	Jul-09	11.97
Sep-08	19.95	Jul-09	12.55
Sep-08	19.2	Jul-09	12.73
Oct-08	18	Jul-09	12.9
Oct-08	18.6	Aug-09	12.5
Oct-08	18.35	Aug-09	12.56
Oct-08	19.1	Aug-09	12.4
Oct-08	20.01	Aug-09	12.4
Oct-08	18.8	Aug-09	12.52
Oct-08	17.2	Aug-09	12.75
Oct-08	14.8	Aug-09	13.07
Nov-08	11.6	Sep-09	13.02
Nov-08	15.22	Sep-09	13.26
Nov-08	15.3	Sep-09	13.6
Nov-08	15.25	Sep-09	13.33
Nov-08	15.25	Sep-09	12.99
Nov-08	14.8	Sep-09	12.03
Nov-08	13.8	Oct-09	12.11
Nov-08	14.1	Oct-09	12.05
Dec-08	13.9	Oct-09	12.09
Dec-08	13.99	Oct-09	12.67
Dec-08	12.9	Oct-09	13.5
Dec-08	13.06	Oct-09	13.7
Dec-08	13.15	Oct-09	13.48
		Oct-09	14.28
		Nov-09	13.64
		Nov-09	13.66
		Nov-09	12.94
		Nov-09	12.49
		Nov-09	12.51
		Nov-09	12.47
		Nov-09	11.97
		Dec-09	12.23

	Dec-09	12.55	
	Dec-09	12.58	
	Dec-09	13.5	
	Dec-09	12.05	

APPENDIX C

The cash flow of the project is expressed in the appendix. In additional, Simulator will generate random numbers and variants during the simulation process so the numbers in the Tables C1 and C2 do not represent the results of the actual simulation

Table C1: Cash flow model of the project

CASHFLOW																	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Undiscounted Cash Flow																	
Gross Revenue (MM$)	249.17	394.39	599.51	580.31	503.88	495.07	533.71	537.27	506.96	562.66	494.99	462.12	459.93	444.39	480.05	497.25	445.60
Exploration costs (MM$)	19.36	14.46	14.84	15.44	14.69	15.04	15.36	13.89	4.34	4.16	4.27	3.89	3.80	3.93	3.73	3.80	3.86
Development costs (MM$)	240.00	236.00	215.00	213.00	188.00	185.00	184.00	200.00	195.00	168.86	168.89	166.56	158.18	0.00	0.00	0.00	0.00
Operating costs (MM$)	160.00	180.00	200.00	200.00	170.00	160.00	165.00	160.00	160.00	155.00	152.00	150.00	104.00	104.16	110.05	99.50	103.93
Royalty (12.5%) (MM$)	31.15	49.30	74.94	72.54	62.99	61.88	66.71	67.16	63.37	70.33	61.87	57.77	57.49	55.55	60.01	62.16	55.70
Petroleum Income Tax (50%)	0.00	0.00	47.37	39.67	34.10	36.57	51.32	48.11	42.13	82.16	53.98	41.95	68.23	140.38	153.13	165.90	141.06
Net Cash Flow (MM$)	-201.33	-85.38	47.37	39.67	34.10	36.57	51.32	48.11	42.13	82.16	53.98	41.95	68.23	140.38	153.13	165.90	141.06
Net Cash Flow @ DC (MM$)	-201.33	-70.56	35.59	27.09	21.18	20.64	26.33	22.44	17.87	31.68	18.92	13.37	19.76	36.97	36.66	36.10	27.91
Cumm. cash flow (MM$)	-201.33	-271.89	-236.30	-209.21	-188.03	-167.39	-141.05	-118.61	-100.75	-69.07	-50.15	-36.78	-17.02	19.95	56.60	92.71	120.62
(Continue)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	
Gross Revenue (MM$)	502.65	475.77	520.63	426.08	469.78	434.36	467.65	536.79	299.88	163.51	170.19	146.10	142.53	114.16	117.70	111.99	
Exploration costs (MM$)	3.82	3.68	3.92	3.71	4.24	4.34	3.87	4.04	4.29	3.74	4.07	4.08	3.84	4.05	3.92	4.14	
Development costs (MM$)	0.00	0.00	0.00	16.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Operating costs (MM$)	102.93	102.77	97.00	94.29	97.27	99.41	100.41	104.52	111.02	110.45	95.68	101.65	107.87	99.84	109.11	420.64	
Royalty (12.5%) (MM$)	62.83	59.47	65.08	53.26	58.72	54.29	58.46	67.10	37.48	20.44	21.27	18.26	17.82	14.27	14.71	14.00	
Petroleum Income Tax (50%)	166.54	154.93	177.32	129.37	154.77	138.16	152.46	180.57	73.54	14.44	24.58	11.06	6.50	0.00	0.00	0.00	
Net Cash Flow (MM$)	166.54	154.93	177.32	129.37	154.77	138.16	152.46	180.57	73.54	14.44	24.58	11.06	6.50	-3.99	-10.04	-326.78	
Net Cash Flow @ DC (MM$)	29.95	25.33	26.36	17.48	19.01	15.43	15.48	16.67	6.17	1.10	1.70	0.70	0.37	-0.21	-0.48	-14.07	
Cumm. cash flow (MM$)	150.57	175.90	202.26	219.74	238.75	254.18	269.66	286.33	292.50	293.60	295.30	296.00	296.37	296.16	295.69	281.62	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Gas Production per DAY (MMSCF)	192,880	185,148	281,651	284,559	313,964	318,144	292,902	288,928	305,360	272,230	311,840	330,527	330,544	339,811	318,084	307,946	338,478
Gas sale production (MMBTU) per yr	59,406,995	57,025,670	86,748,604	87,644,029	96,700,819	97,988,377	90,213,931	88,989,904	94,051,000	83,846,825	96,046,760	101,802,402	101,807,682	104,661,799	97,969,907	94,847,393	104,251,375
Gas sale (MM$)	191.71	184.02	279.94	282.83	312.05	316.21	291.12	287.17	303.50	270.57	309.94	328.52	328.53	337.74	316.15	306.07	336.42
LPG Production per DAY (BBL)	2,952.48	10,832.50	16,456.21	15,317.68	9,871.09	9,202.60	12,488.22	12,875.19	10,470.56	15,040.16	9,521.91	6,869.82	6,755.68	5,480.14	8,431.38	9,837.70	5,610.68
LPG Production (BBL) per yr	909,364	3,336,410	5,068,514	4,717,845	3,040,295	2,834,402	3,846,370	3,965,558	3,224,932	4,632,371	2,932,750	2,115,906	2,080,749	1,687,882	2,596,864	3,030,011	1,728,090
LPG sale (MM$)	21.13	77.54	117.79	109.64	70.66	65.87	89.39	92.16	74.95	107.66	68.16	49.17	48.36	39.23	60.35	70.42	40.16
Total sales (MM$)	212.84	261.56	397.73	392.47	382.71	382.08	380.51	379.33	378.45	378.23	378.10	377.69	376.89	376.97	376.50	376.49	376.58
(Continue)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	
Gas Production per DAY (MMSCF)	304,417	320,092	293,006	313,292	256,526	250,346	206,099	115,475	211,281	122,332	96,917	93,366	77,924	80,785	63,229	54,806	
Gas sale production (MMBTU) per yr	93,760,380	98,588,361	90,245,909	96,494,055	79,010,069	77,106,530	63,478,537	35,566,316	65,074,493	37,678,214	29,850,345	28,756,716	24,000,645	24,881,807	19,474,534	16,880,107	
Gas sale (MM$)	302.56	318.14	291.22	311.39	254.97	248.82	204.85	114.77	210.00	121.59	96.33	92.80	77.45	80.29	62.84	54.47	
LPG Production per DAY (BBL)	10,297	8,108	11,809	5,896	11,058	9,550	13,534	21,743	4,622	2,155	3,802	2,743	3,350	1,742	2,824	2,961	
LPG Production (BBL) per yr	3,171,483	2,497,219	3,637,111	1,815,993	3,405,960	2,941,361	4,168,449	6,696,966	1,423,606	663,615	1,170,953	844,754	1,031,838	536,420	869,866	912,130	
LPG sale (MM$)	73.71	58.04	84.53	42.20	79.15	68.36	96.87	155.64	33.08	15.42	27.21	19.63	23.98	12.47	20.22	21.20	
Total sales (MM$)	376.27	376.18	375.75	353.59	334.12	317.18	301.72	270.41	243.08	137.01	123.54	112.43	101.43	92.76	83.06	75.67	
NPV : DC10% (MM$)	**281.62**																
IRR	**18%**																

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Table C1: Cash flow model of the project (Continue)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
CCS CAPEX DEPRECIATION at $276.63 million US (SOYD)	16.27	15.78	15.29	14.79	14.30	13.81	13.31	12.82	12.33	11.83	11.34	10.85	10.36	9.86	9.37	8.88	8.38
CO2 Emission (million tonne/yr)	0.56	0.49	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83
CER's Trading Value for 21 years (MM$)	10.48	9.06	15.46	15.46	15.46	15.46	15.46	15.46	15.46	15.46	15.46	15.46	15.46	15.46	15.46	15.46	15.46
CER Registration (MM$)	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPEX (MM$)	14.75	12.75	21.77	21.77	21.77	21.77	21.77	21.77	21.77	21.77	21.77	21.77	21.77	21.77	21.77	21.77	21.77
CF of CCS with CERs 21 years (MM$)	-20.74	-19.47	-21.59	-21.10	-20.60	-20.11	-19.62	-19.12	-18.63	-18.14	-17.64	-17.15	-16.66	-16.17	-15.67	-15.18	-14.69
CF of CCS with CERs 10 years (MM$)	-20.74	-19.47	-21.59	-21.10	-20.60	-20.11	-19.62	-19.12	-18.63	-18.14	-17.64	-32.61	-32.12	-31.63	-31.14	-30.64	-30.15
CF of CCS with CERs 7 years (MM$)	-20.74	-19.47	-21.59	-21.10	-20.60	-20.11	-19.62	-19.12	-34.09	-33.60	-33.11	-32.61	-32.12	-31.63	-31.14	-30.64	-30.15
CF of CCS @10%DC 21 years (MM$)	-20.74	-16.09	-16.22	-14.41	-12.79	-11.35	-10.07	-8.92	-7.90	-6.99	-6.18	-5.46	-4.83	-4.26	-3.75	-3.30	-2.91
CF of CCS @10%DC 10 years (MM$)	-20.74	-16.09	-16.22	-14.41	-12.79	-11.35	-10.07	-8.92	-7.90	-6.99	-6.18	-10.39	-9.30	-8.33	-7.45	-6.67	-5.96
CF of CCS @10%DC 7 years (MM$)	-20.74	-16.09	-16.22	-14.41	-12.79	-11.35	-10.07	-8.92	-14.46	-12.95	-11.60	-10.39	-9.30	-8.33	-7.45	-6.67	-5.96
CF of CCS w/o CERs (MM$)	-31.03	-28.53	-37.05	-36.56	-36.07	-35.57	-35.08	-34.59	-34.09	-33.60	-33.11	-32.61	-32.12	-31.63	-31.14	-30.64	-30.15
CF of CCS w/o CERs@10%DC (MM$)	-31.03	-23.58	-27.84	-24.97	-22.39	-20.08	-18.00	-16.14	-14.46	-12.95	-11.60	-10.39	-9.30	-8.33	-7.45	-6.67	-5.96
CER's Trading Value @10%DC (MM$)	10.48	7.49	11.62	10.56	9.60	8.73	7.94	7.21	6.56	5.96	5.42	4.93	4.48	4.07	3.70	3.37	3.06
NPV of with CERs @10%DC 21 years (MM$)	-222.08	-86.65	19.37	12.68	8.38	9.29	16.27	13.52	9.96	24.68	12.73	7.90	14.94	32.71	32.91	32.80	25.00
NPV of with CERs @10%DC 10 years (MM$)	-222.08	-86.65	19.37	12.68	8.38	9.29	16.27	13.52	9.96	24.68	12.73	2.98	10.46	28.64	29.20	29.44	21.94
NPV of with CERs @10%DC 7 years (MM$)	-222.08	-86.65	19.37	12.68	8.38	9.29	16.27	13.52	3.41	18.72	7.32	2.98	10.46	28.64	29.20	29.44	21.94
NPV of w/o CERs @10%DC (MM$)	-232.36	-94.14	7.75	2.12	-1.22	0.56	8.33	6.31	3.41	18.72	7.32	2.98	10.46	28.64	29.20	29.44	21.94

(Continue)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
CCS CAPEX DEPRECIATION at $276.63 million US (SOYD)	7.89	7.40	6.90	6.41	5.92	5.42	4.93	4.44	3.94	3.45	2.96	2.47	1.97	1.48	0.99	0.49
CO2 Emission (million tonne/yr)	0.83	0.83	0.83	0.83	0.89	0.71	0.58	0.33	0.60	0.35	0.27	0.26	0.22	0.23	0.18	0.16
CER's Trading Value for 21 years (MM$)	15.46	15.46	15.46	15.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CER Registration (MM$)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPEX (MM$)	21.77	21.77	21.77	21.77	23.27	18.60	15.31	8.58	15.70	9.09	7.20	6.94	5.79	6.00	4.70	4.07
CF of CCS with CERs 21 years (MM$)	-14.19	-13.70	-13.21	-12.71	-29.19	-24.02	-20.24	-13.02	-19.64	-12.54	-10.16	-9.40	-7.76	-7.48	-5.68	-4.56
CF of CCS with CERs 10 years (MM$)	-29.66	-29.16	-28.67	-28.18	-29.19	-24.02	-20.24	-13.02	-19.64	-12.54	-10.16	-9.40	-7.76	-7.48	-5.68	-4.56
CF of CCS with CERs 7 years (MM$)	-29.66	-29.16	-28.67	-28.18	-29.19	-24.02	-20.24	-13.02	-19.64	-12.54	-10.16	-9.40	-7.76	-7.48	-5.68	-4.56
CF of CCS @10%DC 21 years (MM$)	-2.55	-2.24	-1.96	-1.72	-3.59	-2.68	-2.06	-1.20	-1.65	-0.96	-0.70	-0.59	-0.44	-0.39	-0.27	-0.20
CF of CCS @10%DC 10 years (MM$)	-5.33	-4.77	-4.26	-3.81	-3.59	-2.68	-2.06	-1.20	-1.65	-0.96	-0.70	-0.59	-0.44	-0.39	-0.27	-0.20
CF of CCS @10%DC 7 years (MM$)	-5.33	-4.77	-4.26	-3.81	-3.59	-2.68	-2.06	-1.20	-1.65	-0.96	-0.70	-0.59	-0.44	-0.39	-0.27	-0.20
CF of CCS w/o CERs (MM$)	-29.66	-29.16	-28.67	-28.18	-29.19	-24.02	-20.24	-13.02	-19.64	-12.54	-10.16	-9.40	-7.76	-7.48	-5.68	-4.56
CF of CCS w/o CERs@10%DC (MM$)	-5.33	-4.77	-4.26	-3.81	-3.59	-2.68	-2.06	-1.20	-1.65	-0.96	-0.70	-0.59	-0.44	-0.39	-0.27	-0.20
CER's Trading Value @10%DC (MM$)	2.78	2.53	2.30	2.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPV of with CERs @10%DC 21 years (MM$)	27.40	23.09	24.39	15.76	15.43	12.75	13.42	15.46	4.52	0.14	1.00	0.10	-0.07	-0.60	-0.74	-14.27
NPV of with CERs @10%DC 10 years (MM$)	24.62	20.56	22.10	13.67	15.43	12.75	13.42	15.46	4.52	0.14	1.00	0.10	-0.07	-0.60	-0.74	-14.27
NPV of with CERs @10%DC 7 years (MM$)	24.62	20.56	22.10	13.67	15.43	12.75	13.42	15.46	4.52	0.14	1.00	0.10	-0.07	-0.60	-0.74	-14.27
NPV of w/o CERs @10%DC (MM$)	24.62	20.56	22.10	13.67	15.43	12.75	13.42	15.46	4.52	0.14	1.00	0.10	-0.07	-0.60	-0.74	-14.27

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Table C2: Summary of CCS and NPV

Cost of CCS Project	**CAPEX (MM$)**	**OPEX (€ per tCO_2)**
Capture	-	-
Compression	92	4.10
Transport	15	0.10
Storage	340	1.80
Total	446	5.60
SUMMARY		
NPV base case (MM$)		297
NPV with 7 years CERs @10%DC (MM$)		51.57
NPV with 10 years CERs @10%DC (MM$)		68.93
NPV with 21 years CERs @10%DC (MM$)		102.23
NPV without CERs @10%DC (MM$)		-20.67
IRR base case		18%
IRR with 7 years CERs		12%
IRR with 10 years CERs		12%
IRR with 21 years CERs		13%
IRR without CERs		-
CCS cost per tCO_2		$41.09

VITAE

Monsan Kantham was born on Octerber 26,1984 in Chiangmai, Thailand. He received his B.Eng in Civil Engineering from the Faculty of Engineering, Chulalongkorn University in 2008. After graduating, he continues his studies in the Master of Petroleum Engineering program at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University.