UNIVERSITY OF CAPE COAST

ENERGY-ECONOMIC ANALYSIS OF POWER PLANT CARBON DIOXIDE CAPTURE AND PIPELINE TRANSPORT IN TEXAS GULF COAST

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Energy-Economic Analysis of Power Plant Carbon Dioxide Capture and Pipeline Transport in Texas Gulf Coast

by

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Thesis submitted to the Department of Physics of the School of Physical Sciences, Faculty of Science, University of Cape Coast in partial fulfilment of the requirements for the award of Doctor of Philosophy Degree

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DECLARATION

Candidate's Declaration

I hereby declare that this thesis is the result of my own original research and that no part of it has been presented for another degree in this University or elsewhere.

Signature ………………………….. Date…11th November 2009

Joseph Kow Essandoh-Yeddu (Candidate)

Supervisors' Declaration

We hereby declare that the preparation and presentation of the thesis were supervised in accordance with the guidelines on supervision of thesis laid down by the University of Cape Coast.

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ABSTRACT

The total investment cost of a pipeline network to transport carbon dioxide (CO_2) from power plants for enhanced-oil-recovery (EOR) in oil fields in Texas Gulf Coast as CO_2 mitigation has been estimated. The impact of the CO_2 capture and transport on power generation cost, including the benefits of atmospheric CO_2 mitigation has also been determined. 14 power plants comprising 55.7% of installed capacity in Texas Gulf Coast were selected. Geographical-information-system was used to optimise the pipeline network. Absorption amine technology was adopted for the CO_2 capture. Bernoulli's equation was used to model the fluid transmission. Cost escalation factors were introduced into existing pipeline models to improve their estimation capability. The analysis shows that cost of the proposed pipeline transport is highly sensitive to escalations in labour, material and right-of-way costs and would range from $1.6-4.6 billion. The percentage incremental generation cost for coal-fired plants ranges from 55-122% whilst that of gas-fired ranges from 9-13%. Some by-products from the capture could be sold to reduce elevated generation costs. The results indicate 3-7% reduction in Texas' power plant annual emissions which could increase three to fourfold if EOR includes geologic sequestration. Overall, it has the potential to create between 7,000-10,000 new jobs.

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DEDICATION

To my better-half Mrs. Faustina Essandoh-Yeddu, children; Priscilla, Paa Kwesi, Jojo and Albert Owusu and rest of future generation of mankind.

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LIST OF ACRONYMS

\$/MWh	Dollar per Megawatt-hour
\$/tonne	Dollar per tonne
°F / °C	Degree Fahrenheit / Degree Celsius
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
atm	Atmosphere
BAU	Business-as-usual
bbl	Barrel
Bcf / scf	Billion Cubic Feet / standard cubic feet
BEG	Bureau of Economic Geology of UT-Austin
CCGT	Combined Cycle Gas Turbine technology
CCS	Carbon Capture and Storage
CDIA	Carbon Dioxide Information Analysis Center
CF	Capacity Factor
CH_4	Methane
CO_2 / CO	Carbon dioxide / Carbon monoxide
CO_2-EOR	Carbon dioxide based Enhanced Oil Recovery
CRF	Capital Recovery Factor
EOR	Enhanced Oil Recovery
EPRI	Electric Power Research Institute
F O&M	Fixed Operation and Maintenance

g / kg	Gramme / kilogramme
GHG	Greenhouse Gas
GIS	Geographical Information Service
gtC / gtCO_2	Gigatonne-carbon / Gigatonne-carbon dioxide
GWh / MWh	Gigawatt-hour / Megawatt-hour
IDC	Interest During Construction of a plant
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle technology
IPCC	Intergovernmental Panel on Climate Change
Kg/GJ-fuel	Kilogramme per Gigajoule per fuel
Kg/MWh	Kilogramme per Megawatt-hour
kJ / MJ / GJ	Kilojoule / Megajoule / Gigajoule
kPA / MPa	Thousand Pascal / Million Pascal
KWh	Kilowatt-hour
kWh/tCO_2	Kilowatt-hour per tonne carbon dioxide
LCRA	Lower Colorado River Authority
LHV / HHV	Low Heating Value / High Heating Value
MBTU or mbtu	Thousand British Thermal Unit
MMBO or mmbo	Million barrels of oil
MMBTU or mmBTU	Million British Thermal Unit
MMSCF or mmscf	Million Standard Cubic Feet
MSCF or mscf	Thousand Standard Cubic Feet

$MtCO_2$	Thousand tonnes of Carbon dioxide
MWh/year	Megawatt-hour per year
NETL	National Energy Technology Laboratory of United States
NO_x	Nitrogen oxides
O & M	Operation and Maintenance
PM	Particulate matter
ppmv	Parts per million by volume
PSI / psia	Pound per square inch
RN	Radio-nuclides
ROW	Right-of-Way
SO_2 / SO_x	Sulphur dioxide / Sulphur oxides
UNFCCC	United Nations Framework Convention for Climate Change
US DOE	United States Department of Energy
US EIA	United States Energy Information Administration
US EPA	United States Environmental Protection Agency
US FERC	United States Federal Energy Regulatory Commission
UT-Austin	University of Texas at Austin
V O&M	Variable Operation and Maintenance
VHC	Volatile Hydrocarbons
W / KW / MW / GW	Watt / Kilowatt / Megawatt / Gigawatt

CHAPTER ONE

INTRODUCTION

Climate Change

Energy and environment

Energy is required for economic development. As the economy and population expand, demand for energy in the form of electricity, process heat and motive power increases (Figure 1).

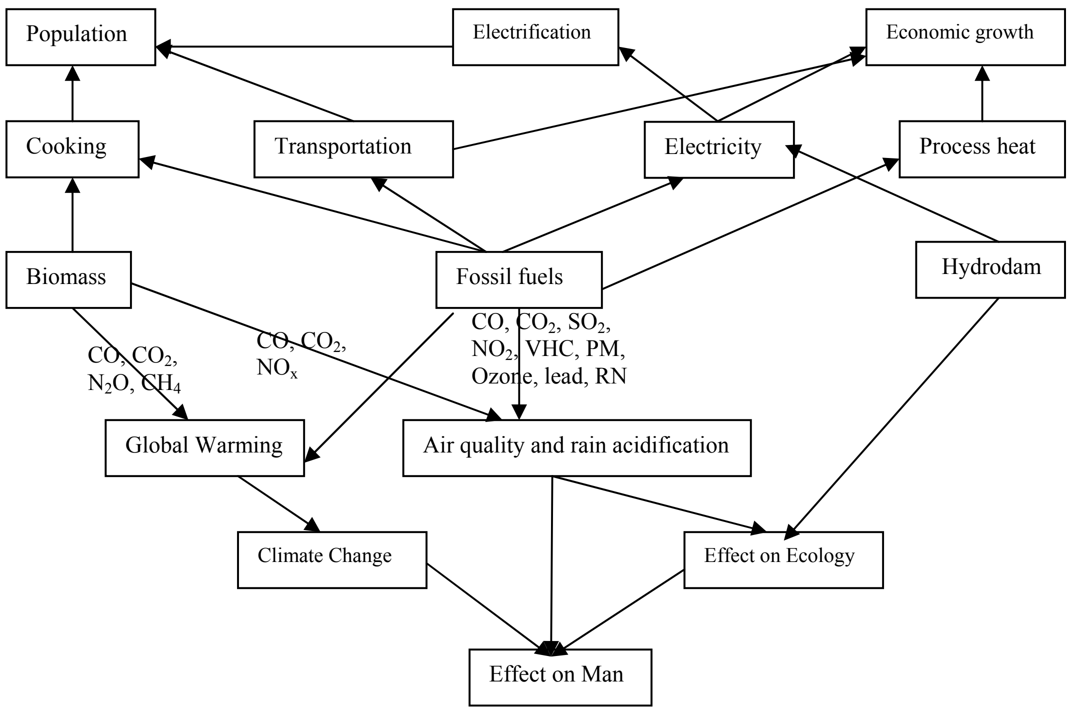

Figure 1. Conceptual Model of Environmental implications of energy usage

Carbon-based fuels, including coal, oil, gas and wood, have dominated global energy supply (81%) since the industrial revolution, starting in the mid eighteenth century (InterAcademy Council, 2007). Extraction, processing, transportation and conversion of these carbon-based fuels for electricity generation, transportation, process heating and cooking have been associated with continuous emission of potentially harmful products including carbon dioxide, carbon monoxide, sulphur dioxide, etc which could cause long-term changes in the atmosphere including increased temperatures, (usually referred to as global warming) and acid rain as shown in **Figure 1**.

The climate and greenhouse gas effect

Climate is often defined as average weather and is usually described in terms of mean and variability of temperature, precipitation and wind over a period of time ranging from few months to millions of years. Climate Change is defined as a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods. Climate System means the totality of the atmosphere, hydrosphere, biosphere and geosphere and their interactions (UNFCCC, 2005a).

The amount of solar energy reaching the top of earth's atmosphere each second on a surface of one square metre facing the sun during daytime is about 1,370 Watts. Roughly, one-third of the solar radiation reaching the top of the earth's atmosphere is reflected back to space. The remaining two-thirds is absorbed by the land and the ocean and to a lesser extent by the atmosphere. The solar radiation hitting the earth's surface is radiated back to the atmosphere but in longer wavelengths (infrared radiation).

Greenhouse gases absorb and re-radiate the longer wavelengths creating more warmth or infrared radiation. This is called the *greenhouse effect*. Water vapour, carbon dioxide, nitrous oxide, methane and ozone are the primary greenhouse gases in the earth's atmosphere. There are also a number of manmade greenhouse gases such as halo-carbons and bromide containing substances (Young, 1980).

Carbon dioxide (CO_2), most significant GHG, transmits **visible light** but absorbs strongly in the **infrared** and **near-infrared** of the electromagnetic spectrum.The greenhouse effect of the earth's atmosphere is largely attributed to water vapour and the carbon dioxide.

It has been estimated that prior to 1700, i.e. before the industrial revolution, the concentration of CO_2 in the atmosphere had been stable at approximately 288 parts per million by volume (ppmv). With the onset of the industrial revolution (in the mid 1800s), when humankind began to burn fossil fuels for energy largely required for the industrialisation, the global CO_2 level began to rise to the present level of about 383 ppmv of which Africa is said to be responsible for less than 3% (Trenberth, Christy, & Olson, 1988).

Stern (2007) estimated that at least $2^{o}C$ rise in global temperature would potentially decrease water availability and crop yield in Africa by 20-30% and 5-10% respectively and that 20-30 million more people would be exposed to malaria, a parasite transmitted by mosquitoes.

Scientific evidence of potential human interference with the climate first emerged in the international public arena at the First World Climate Conference sponsored by World Meteorological Organisation and held in Geneva, Switzerland, from 12-23 February, 1979 (UNFCCC, 2005b).

IPCC, UNFCCC and climate change negotiations

Intergovernmental Panel on Climate Change

Increasing public awareness of environmental issues compelled governments to act. In 1988, the United Nations General Assembly adopted a resolution (*called 43/53 and proposed by Malta*) urging "protection *of global climate for present and future generations of Mankind"* (UNFCCC, 2005b).

In the same year (1988), recognising the possible relationship between concentration of greenhouse gases (GHG) and other emissions in the environment and their potential impact on climate, the World Meteorological Organisation and the United Nations Environment Programme established the Intergovernmental Panel on Climate Change (IPCC) as an effort by the United Nations to provide the governments of the world with a clear scientific view of what is happening to the global climate. *{The role of IPCC was not to carry out new research or monitor climate related data but to assess mainly published material and peer-reviewed scientific technical literature} (IPCC, 2009).*

In 1990, the IPCC issued its First Assessment Report which sought to confirm that the threat of climate change was real. The Second World Climate Conference held in the same year called for the creation of global climate change treaty.

UNFCCC

With the concern that the global average temperature might be increasing at a rate unprecedented in the history of humankind because of higher than expected emissions of anthropogenic GHG, the United Nations General Assembly responded by passing a resolution (45/212) formally commencing negotiations on a convention on climate change in 1991. The following year (1992) member countries of the United Nations joined hands in Rio de Janeiro, Brazil to enact and adopt an international treaty – United Nations Framework Convention for Climate Change (UNFCCC) - to begin considering what could be done to reduce the greenhouse gas emissions and to find ways to cope with the inevitable atmospheric temperature increases.

The IPCC (2007) has concluded that anthropogenic (i.e. manmade) GHG emissions are the leading cause of climate change and that CO_2 is contributing 92.6% of the total greenhouse gases (GHG) in the earth's atmosphere. IPCC (2007) states that 26-30 gigatonnes CO_2 (7-8 gigatonnes carbon) per year which is almost 60% of the annual global GHG emissions are from combustion of fossil fuels and that it is likely to double by 2050. This could lead to 2^oC rise in global mean temperature and would cause catastrophic damage in many places of the earth (IPCC, 2007). However, the 2-degree Celsius temperature would not be exceeded if the concentration of GHG in the atmosphere remains under 500 (±50) ppmv by 2050, says IPCC (2007).

IPCC (2007) therefore reports that stabilizing the global emissions at 500 (±50) ppmv requires that the global CO_2 emissions are held at about the present level of 26-30 gigatonnes ($gtCO_2$) per year. Future emissions of CO_2 are projected to range from 29-44 $gtCO_2$ (8–12 gtC) per year by 2020, and up to 84 $gtCO_2$ (23 gtC) per year by 2050 (IPCC, 2005). This means cutting potential growth in annual global CO_2 emissions by 45-80% by 2050.

An examination of the limits on GHG emissions over the long term necessary to keep the global warming temperatures to below $2^{o}C$ is an essential parameter for negotiating emission reduction requirements for industrialized countries (referred to as Annex 1 countries) as well as understanding the scale of mitigation and adaptation efforts needed in developing countries (UNFCCC, 2005b).

From the practical perspective, the developed countries generally accept responsibility for the historical or elevated GHG concentrations.

Kyoto Protocol

The Kyoto Protocol, a more powerful treaty with legally binding measures was therefore adopted in 1997 in Kyoto Japan, to strengthen the UNFCCC. The Kyoto Protocol commits and sets quantified reduction or limitation targets of greenhouse gases (GHG) for developed countries and countries undergoing economic transition. These targets were to be achieved over the period 2008–2012 usually referred to as first commitment period. The Kyoto Protocol entered into force on February 16, 2005 after Russian Federation, a major emitter ratified it in late 2004. The aim of the global effort was to reduce the total global GHG emissions then, by at least 5% to pre-1990 levels which is said to be about 350 ppmv. Thus 1990 became the ‘baseline’ year for the Kyoto Protocol. For now, it also meant reducing the prevailing levels of about 383 ppmv to 350 ppmv.

The first Kyoto Protocol’s members of parties conference was held in Montreal, Canada in 2005. Over 160 countries have ratified the UNFCCC and about 80% of them including Ghana are parties to the Kyoto Protocol.

The Kyoto Protocol expires in 2012; therefore, there is another negotiating process in motion to enact a new agreement to replace it. The negotiating process would look at setting new commitment period (s) and agreeing on new emission cuts.

The atmosphere and greenhouse effect

The atmospheric system usually referred to as the earth’s aura is highly complex and somehow arranged in a succession of layers. These layers lie closest to the earth at the poles and gradually expand to higher altitudes towards the equator. Their heights also vary a little from day to day and from season to season (Young, 1980).

The first layer, the troposphere contains the atmosphere in the form we are familiar with here on earth. It is about 10 km high at the poles and about 15 km at the equator. The air density decreases with increasing altitude and temperature drops on the average, about $2^{o}C$ for almost every 300 metres. Then suddenly as higher altitudes are attained the temperature stops falling; levels out and begins to rise slowly. The place where the temperature reversal occurs is called the *tropopause* and it is the dividing line between the troposphere and the stratosphere.

Figure 2 shows an approximate vertical section of the lowest 150 km of the earth's atmosphere in the tropics, taking cognisance that there are seasonal variations which are prominent in the mid-latitudes but minimal in the tropics.

ALTITUDE	LAYER	CHARACTERISTICS	PRESSURE (Atmospheres)
130 -150 km	**Ionosphere**	Meteors, aurora, noted for aiding short –medium radiowave transmission around the globe	0.000001
	Mesopause		
80 – 90 km	**Mesosphere**	Noctilucent clouds	0.001
	Stratopause		
30 – 35 km	**Stratosphere**	Ozone layer	0.001
	Tropopause		
10 – 15 km	**Troposphere**	Most clouds, weather formation, normal man habitation	0.1
0 km	**Ground level**		1.0

Adapted from Earth's Aura (Young,1980)

Figure 2. Vertical layers of the Earth's atmosphere as measured in the tropics.

In the stratosphere, the tenuous air becomes highly charged. Widely diffused throughout the stratosphere is ozone forming a layer which blocks most of the ultra-violet radiation from the sun by converting it mostly into heat. The ozone layer besides protecting life on earth from the lethal ultra-violet rays, also maintains heat balance in the upper atmosphere. Decreases in stratospheric ozone changes the heat balance in stratosphere and have the potential to destabilise the climate (Young 1980).

At a height of about 50 km, lies the *stratopause* where another temperature reversal takes place. Above the stratopause is the mesosphere, a relatively quiescent cold region where icy-vapour clouds called noctilucent clouds are sighted. Dust particles known to be debris from meteorites are also present (Young 1980). The temperature decline reaches its lowest point at the *mesopause*.

Above the mesopause is the ionosphere, where temperature begins to rise again. It is in the ionosphere where most meteors entering the earth atmosphere are burnt out. The ionosphere is also significant in radio broadcast transmission. Long distance medium and short radiowaves become possible by successive bouncing of the waves off the earth's surface and the ionosphere.

The troposphere where human life resides and climate changes take place contains approximately 78.08% nitrogen, 20.95% oxygen, 0.93% argon, 0.038% carbon dioxide by volume and trace amounts of other gases. It also contains a variable amount of water vapour, on average approximately 1% (IPCC, 2007).

Mauna Loa Observatory CO_2 measurements

Arrhenius (1896) did a first measurement of the impact that atmospheric CO_2 concentration could have on the earth's surface temperature (Oppenheimer & Petsonk, 2005). The CO_2 measurements (Figure 3) provided by the Mauna Loa Observatory located in Hawaii, USA is however said to constitute the longest continuous record of atmospheric CO_2 concentrations available in the world. The site is also considered as one of the most favourable locations for measuring undisturbed air because possible local influences of vegetation or human activities on atmospheric CO_2 concentrations and any influences from volcanic vents are known to be minimal and excluded from the records. The methods and equipment used to obtain these measurements have remained essentially unchanged during 50 years of the monitoring programme (Keeling, Piper, Bollenbacher, & Walker, 2008).

From the Mauna Loa records, it was estimated that the annual average concentration of CO_2 increased from 317.66 ppmv in 1961 to 383.57 ppmv in 2007 (or 582 parts per million by mass), even though, still considered a **trace gas** representing an average annual growth rate of 1.43 ppmv at Mauna Loa (Keeling et al., 2008). The mass of the earth atmosphere is estimated at **5.15×10^{18} kg**, so the total mass of atmospheric carbon dioxide is 3.0×10^{15} kg ($582 * 10^{-6} * 5.15 \times 10^{18}$ kg) (Trenberth et al., 1988). {***Trace gas*** *refers to a gas or gases which make up less than 1% by volume of the earth's atmosphere, (ESRL, 2008). The mass of the atmosphere ranges from (5.00-5.30)x10^{18} kg as provided by different authors (Campbell, 1977; Lide, 1996; Wayne, 1985)}*.

IPCC (2007) indicated that eleven years of mean annual increment from 1995-2006 rank among the twelve warmest years in the instrumental record of global surface temperature (since 1850). The 100-year (1906-2005) linear annual increment trend of 0.74 (0.56-0.92) °C was larger than the corresponding trend of 0.6 (0.4 - 0.8) °C of (1901-2000) published in the mid-1990s. (IPCC, 2007).

Figure 3 shows the strong correlation between the increasing concentrations of CO_2 in the atmosphere and rising global temperatures (IPCC, 2007).

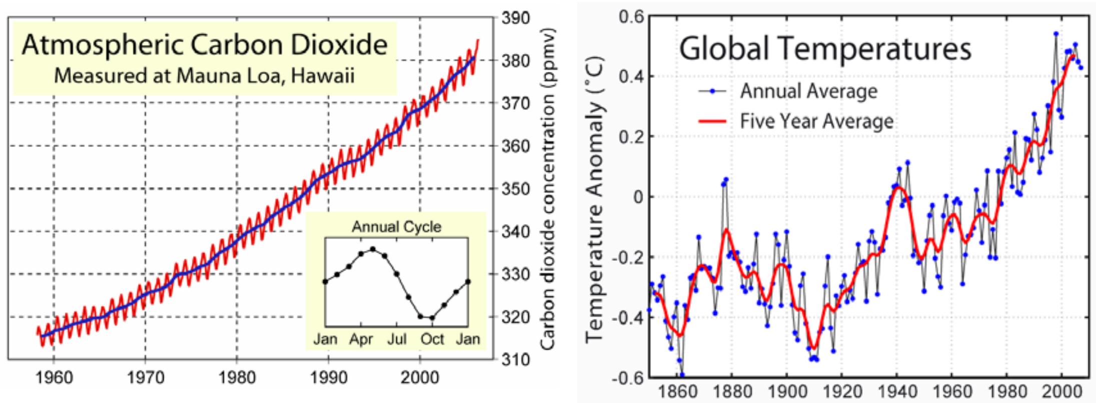

Figure 3. Atmospheric Carbon dioxide concentrations and Global Temperatures (IPCC, 2007)

Alternative viewpoints to the increasing CO_2 concentrations in the atmosphere

There is another viewpoint which believes that the observed temperature changes are caused by natural variance in the earth's climate rather than humans (New Scientist, 2005). Increasing carbon dioxide concentration in the earth atmosphere is not a new phenomenon, according to the alternative view. It is estimated that 500 million years ago, CO_2 concentration in the atmosphere was 20 times higher than today, decreasing to 4-5 times during the Jurassic period (199-145 million years ago) and then maintained a slow decline with a particularly swift reduction until the industrial revolution in mid 1800s (Berner & Kothavala, 2001).

Data knowledge of atmospheric carbon dioxide concentrations before the industrial era to the beginning of modern atmospheric measurements had been obtained from measurements made on air trapped in ice cores drilled mainly from the Antarctica. In January 1998, a collaborative ice-drilling project between Russia, the United States, and France at the Russian Vostock station in East Antarctica yielded the deepest ice core ever recovered, reaching a depth of 3,623 m. Ice cores are unique with their entrapped air inclusions enabling direct records of past changes in atmospheric trace-gas composition. Preliminary data indicated that the Vostock ice-core record extends through four climate cycles, slightly older than 400,000 years (Petit et al., 1999).

Figure 4 also shows a close correlation between Antarctic temperature and atmospheric concentrations of CO_2.

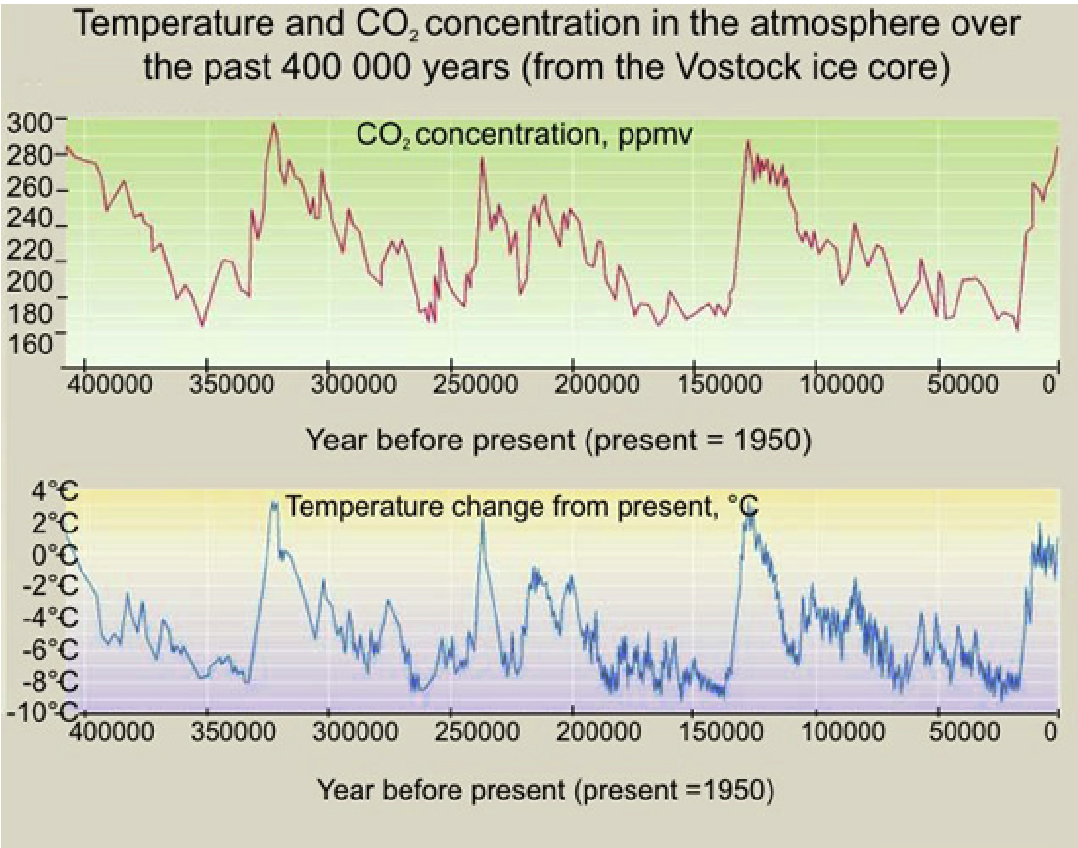

Figure 4. Temperature and CO_2 variations in the earth's atmosphere in the Pre-industrial period from Vostock ice core, Russia, *reproduced from CDIA (2008)*

Estimates from the ice-core measurements also indicated that the earth atmosphere had undergone a cycle of warming and cooling with corresponding increasing and lowering carbon dioxide concentrations every 150,000 years for the past 400,000 years (Figure 4) (CDIA, 2009).

The ice core measurements confirmed the constant concentration of carbon dioxide in the atmosphere of about 280 ppmv before 1800 and a steady increase in an approximately exponential fashion since then.

Vostock CO_2 record further revealed that the main trends of CO_2 were similar for each glacial cycle. Major transitions from the lowest to the highest values were associated with glacial-interglacial transitions. During these transitions, the atmospheric concentrations of CO_2 would rise from 180 to 280-300 ppmv (Petit et al. 1999). When the Vostock ice core data were compared with other ice core data, good agreement was found between the records; all showing low CO_2 values (~200 ppmv) during the Last Glacial Maximum (CDIA, 2008).

Nevertheless, these ice core measurements still attracted some criticisms (Jaworowski, 1996; 1997). To critics, it was difficult to believe that a chemically active gas such as carbon dioxide could remain unaffected by burial in ice for as long as about 150,000 years. There were questions as to whether the carbon dioxide could diffuse through the snow, react with dust particles, or form compounds under pressure. The technique of drilling, removal and preservation of the ice core was a very difficult one, for instance, the ice core must be protected from drilling mud and from entrance of air from the present atmosphere through cracks.

Most of these objections were somehow answered, with another study on ice cores from East Antarctica (Law Dome ice cores, 66°S, 112°E) which involved collaboration between several of the previous teams but with much improved techniques and using lessons from previous studies. (Figure 5) (Etheridges et al., 1996; 1998).

The Law Dome ice core measurements (Figure 5) agreed with the Mauna Loa observations (Figure 3); it showed increasing CO_2 concentration trend from an average of about 288 ppmv during the pre-industrial times to over 330 ppmv today.

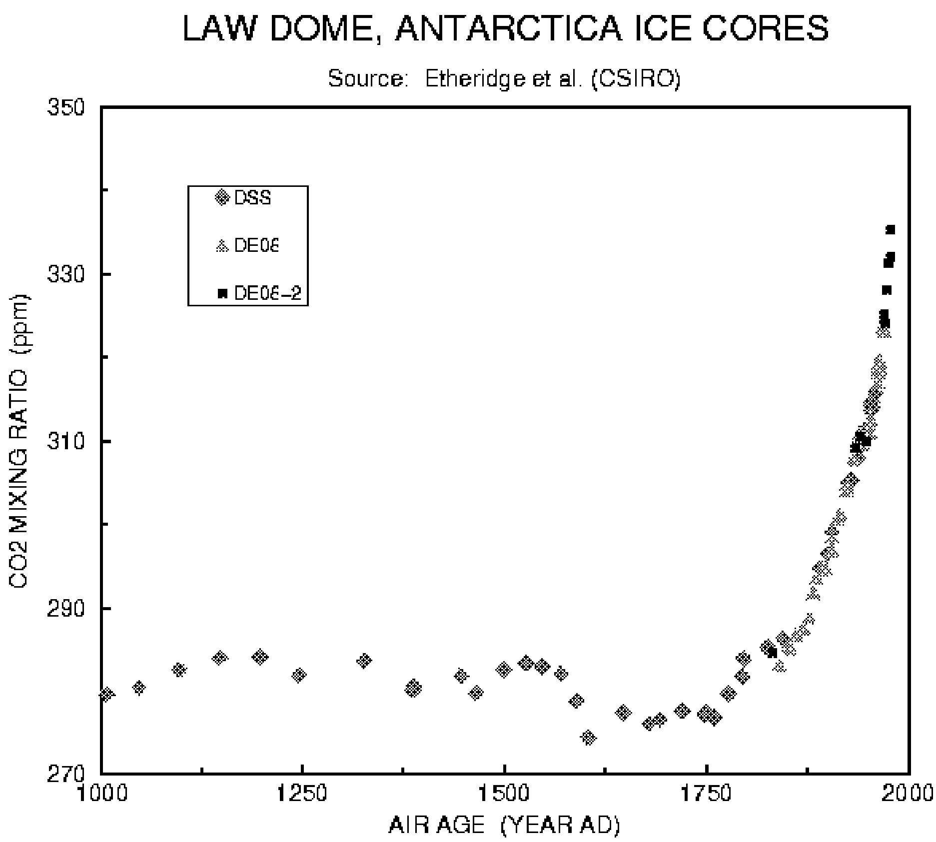

Figure 5. CO_2 concentrations in Law Dome Ice cores, Antarctica (Etheridge et al., 1996)

Some critics accept the natural inter-glacial cyclical warming of the earth (*refer to Figure 4*) but disagree that humankind is contributing significantly to the increasing rate of global warming. They claim mankind should rather be worried about the beginning of a new glacial cycle (Hecht, 2008). They further claim that the entire 0.6 °C rise in average global temperature between 1901-2000 as reported by IPCC (2007) was balanced by an equivalent 10 years of global average temperature decline recorded between 1999-2008.

Natural processes gradually remove CO_2 from the atmosphere, for example, by plant life and dissolution in the ocean. IPCC (2007) indicates that currently, the net removal of atmospheric CO_2 by natural processes is about half the rate of anthropogenic CO_2 emissions, which explains why the concentrations of CO_2 in the atmosphere have increased. Measurement of carbon isotopes in tree rings was also used to investigate the evidence of global warming. Carbon is composed of three different isotopes, ^{14}C, ^{13}C, ^{12}C with the latter as the most common. ^{13}C is about 1% of the total and ^{14}C accounts for only 1 in 1 trillion carbon atoms (Emsley, 2006). Plants have preference for ^{12}C and so have lower $^{13}C/^{12}C$ ratios. Since fossil fuels are believed to have been derived from ancient plants, plants and fossil fuels all have roughly the same $^{13}C/^{12}C$ ratio and is about 2% lower than that of the atmosphere. So, as CO_2 is released during combustion and mixes with the atmosphere, the average $^{13}C/^{12}C$ ratio of the atmosphere decreases. {*The delta [$\delta = {}^{13}C/^{12}C$] also called $\delta^{13}C$ ratio in normal atmosphere is estimated at about -ve7.0 units (permil). Estimates for current atmosphere range from -7.5 to -11 units (*Emsley, 2006)}.

In summary, the earth is warming up on its own as shown in **Figure 4**, but humankind is accelerating the process. Talking about global warming is therefore largely referred to the enhanced greenhouse effect due to anthropogenic effect.

The United States GHG emissions

The United States produces about one-quarter of the world's annual CO_2 emissions and therefore, has a critical leading role to play in changing the increasing global CO_2 emissions trend. US total CO_2 emissions in 2006 was almost 7 gigatonnes and energy-related emissions averaged 6 gigatonnes per year between 2005-2008 (US EPA, 2009).

United States utilised 2.3-2.5 billion tonnes of oil equivalent of energy from 2005-2007 of which 85% came from fossil fuels; comprising 40% crude oil, 23% coal and 22% natural gas. Forty-nine to fifty percent of the electricity produced in the United States from 2005-2007 had come from coal (IPCC, 2007).

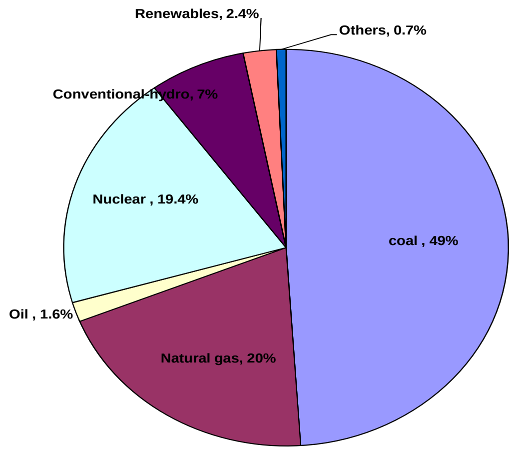

Figure 6. Fuel share for US Electricity production in 2007 (US EIA, 2008)

The Gulf Coast region of the United States comprising Texas, Louisiana, and Mississippi, produces about 16% of the U.S. annual CO_2 emissions from fossil fuels (Duncan, 2004). Texas, the highest carbon dioxide emitter, accounts for over 10% of the United States emissions, emitting about one gigatonnes of CO_2 into the atmosphere in 2006 (US EIA, 2006). **Table 1** shows the profile of CO_2 emissions for Texas and the entire United States.

Table 1: Comparing Energy Industry Profiles of Texas and the entire United States during the period 2005-2007 (US EIA, 2008).

	Texas	**The United States**
Crude Oil production (million bbl/day)	0.9-0.95	5-6
Oil consumption (million bbls/day)	3.2-3.3	20-21
Natural gas production (bcf/day)	15-17	51-52
Natural gas consumption (bcf/day)	9-9.6	60-63
Coal production (million tonnes/ year)	45-46	1,150-1,160
Coal consumption (million tonnes/ year)	103-105	≈ 1,130
Installed power capacity (GW)	≈ 82 (thermal ≈ 72 GW)	≈ 1,100 (thermal ≈ 850 GW)
Electricity consumption (TWh/ year)	315	4,000-4,100
Major sources of electricity ***Depending upon capacity factor / availability of plants***	Coal (40-42%) Natural gas (40-43%) Nuclear (6-12%) Large Hydro (<1%) Renewables (3%) Petroleum (<1%)	Coal (50%) Natural gas (20%) Nuclear (20%) Large Hydro (6-7%) Renewables (1-2%) Petroleum (1-2%)
Electric Power Carbon CO_2 emissions per annum (million tonnes)	250-352	2,700-3,000 (≈ 6,000 total energy-related emissions)

CO_2-EOR as first step solution

As Texas looks for ways to mitigate its CO_2 emissions, BEG (1991) found CO_2 for enhanced oil recovery (CO_2-EOR) as the most viable economic option capable of utilizing the large CO_2 emissions in Texas. BEG (1999) identified 1,730 reservoirs estimated to hold 80 barrels of OOIP to be favourable for CO_2-EOR. The selected fields were also found to be located within 144 km of CO_2 producing sources such as fossil fuel power plants. The study was revised in 1999 and has secured a database of all oil and gas fields and CO_2 sources in Texas as well as inventory of all CO_2-EOR candidate oil fields.

Oil production in Texas Gulf Coast began prior to 1900 and peaked in the early 1970s. Despite efforts to curb production decline through secondary recovery methods, oil production in the Texas Gulf Coast has continued to fall in recent years, despite secondary waterflooding efforts in many of the fields. These secondary recovery methods are now mature, with many of the fields near their production limits and looking for alternative methods for maintaining oil production, if not boosting output. Texas Gulf Coast produced between 41-51 million barrels of oil (114,600 barrels per day) from 2000-2007.

Although the fields are mature and in decline, great opportunities exist for incremental oil recovery by applying CO_2-EOR technology. On average, oil recovery in the major Gulf Coast oil reservoirs has been less than 40%, leaving a large amount of residual oil stranded in the ground (BEG, 1999).

Mitigating Texas' GHG emissions

Overview of CO_2-EOR projects proposed for Texas

CO_2–EOR activities are already proven and taking place in West Texas since 1970s where the CO_2 sources are from natural gas reservoirs (BEG, 1999).

BEG (Duncan, 2004) estimated that outside the traditional area of CO_2 EOR in West Texas around 6 billion barrels of oil more could be produced in other regions in Texas by using CO_2 –EOR and consequently leading to the storage of more than 700 million tonnes (0.7 gigatonne) of CO_2.

US Department of Energy therefore commissioned a group, Advanced Resource International (2006) to look into the possibility of replicating the West Texas' CO_2-EOR activities in East and Central Texas not only to reduce CO_2 emissions in Texas but as part of a larger effort to examine CO_2-EOR in key U.S oil basins. The study:

i. Screened the major oil reservoir database for CO_2-EOR candidates; and
ii. developed economic model and performed scenarios analysis on their potential production.

The study considered a mix of anthropogenic and natural CO_2 by recommending the extension of the CO_2 pipeline network in West Texas to East and Central Texas and also capturing some of the CO_2 from the industrial sources in the region. The emphasis was on the extension of the CO_2 pipeline network from West Texas since the key assumption was that there would be sufficient CO_2

supplies from pipelines in the Permian Basin which takes CO_2 from natural sources in Colorado and New Mexico.

Findings of the Advanced Resource International's Study

Summary of findings of the Advanced Resource International (2006) study were as follows:

1. The original oil resource in East and Central Texas reservoirs was estimated at 109 billion barrels of oil which over 35 billion barrels of it had been recovered or proven. Thus, without further oil recovery methods, nearly 74 billion barrels of East and Central Texas oil resource would become stranded.
2. 161 reservoirs with 53 billion barrels of original oil resource were found to be favourable for CO_2-EOR.
3. The technically recoverable oil from applying CO_2-EOR in these 161 large oil reservoirs ranges from 4,620 million barrels to 10,960 million barrels.
4. With present technology, only 1.6 billion barrels of this "stranded oil" could become economically recoverable {*The study assumed 'economically recoverable' as having oil price of $30 per barrel, a CO_2 delivery price of $1.50 thousand cubic feet (mcf) and a rate of return (ROR) of 25% before tax*}.
5. However with State-of the-art CO_2-EOR technology, 7.3 billion barrels of the stranded oil becomes economically recoverable.
6. Large volumes of CO_2 supplies estimated between 1-2 trillion cubic metres (31-67 trillion cubic feet) shall be required in East and Central

Texas to achieve the CO_2-EOR potential, and would come from both natural and industrial sources.

7. Over 1.5 billion tonnes of CO_2 emissions are expected to be stored, greatly reducing greenhouse gas (GHG) emissions.

8. Successful introduction and wide-scale use of CO_2-EOR in East and Central Texas would stimulate increased economic activity and help revive a declining domestic oil production and service industry.

9. The challenges in realizing these yields are securing; sufficient low-cost CO_2 supplies, uncertainties as to how the technology would perform in many of the oil fields, and considerable market and oil price risk.

To overcome these challenges, the Advanced Resource International (2006) study recommended a partnership involving all the stakeholders; the oil production industry, potential CO_2 suppliers and transporters, the state of Texas and the federal U.S government.

Texas Gulf Coast

The Advanced Resource International (2006) study also took a cursory look at the Texas Gulf Coast and provided some indications (Table 2):

- That Texas Gulf Coast contains 103 reservoirs that are candidates for CO_2-EOR.
- With today's technology, only 15 of them would be economically viable with a yield of only 360 million barrels.
- However applying CO_2-EOR with State-of-the-Art technology would increase the number of economically favourable oil

reservoirs to 58 yielding between 2.7-3.1 billion barrels under different scenarios.

- At lower cost of CO_2, say \$14-15/tonne (\$0.8 per mcf), the number of economically favourable wells could increase to 91 and the yield up to almost 3.8 billion barrels. *{mcf is thousand cubic feet}*

Table 2. Estimated recoverable oil using CO_2-EOR in Texas Gulf Coast (*Advanced Resource International, 2006*)

Technology	Number of Reservoirs	OOIP (mmbbls)	Recoverable with CO_2-EOR (mmbbls)	
			Technical	Economic#
Traditional/Today's	15	20,159	1,780	360
State of the Art	58		2,680-3,140	
State of the Art & Ample supplies and at low price of CO_2	91		3,750	

 # assumes an oil price of \$30-40/ barrel (\$210-280/tonne), a CO_2 cost of \$1.5-2.0/mcf (\$28-38/tonne), Rate of return hurdle rate of 15-25%

Even though, the study provided some scoping data on potential oil recoverable in the Texas Gulf Coast, it was not as in-depth as its coverage of Central and East Texas. For instance the study:

- Covered cost of extending the CO_2 trunk-line from West Texas to the oil fields in Central and East Texas but not extensive on transporting the CO_2 from the industrial sources.

- Did include the cost of extending the CO_2 pipeline trunk-line from West Texas to Texas Gulf Coast but did not cover the cost of transporting CO_2 from industrial/anthropogenic sources.
- Did not cover or discuss the CO_2 capture technology and the cost involved.

Opportunities for CO_2-EOR in Texas Gulf Coast

The Texas Gulf Coast having high concentration of CO_2 emission sources also provides a good opportunity for addressing the CO_2 emissions problem due to:

- The presence of a variety of potential large-volume CO_2 sequestration sinks (i.e. subsurface storage of CO_2 in oil fields, gas fields, the associated permeable-non-productive brine-bearing formation, and coal seams).
- The wealth of geological knowledge of the subsurface in the region and the existing experience, for example, in permitting injection wells and pipeline construction.

The close proximity of CO_2 stationary and point sources such as power plants and the refineries makes the Texas Gulf Coast ideal for anthropogenic CO_2-EOR applications.

Objectives of Research Work in Texas Gulf Coast

Electricity generation in Texas is 80-86% thermal and forty to forty-two percent comes from coal. The coal mines alone employ between 2,000-2,200 persons every year. Of the electricity generation, coal power is the least expensive source of electricity. Annual electricity sales ranged between \$30-36 billion between 2005-2007; it was \$35.4 billion in 2006 up from \$30.6 billion in 2005 (King, Essandoh-Yeddu, Gulen, & Hovorka, 2009).

In the United States as a whole, 2.7-3 billion tonnes (2.7-3 gigatonnes) of CO_2 come from power plant operations of which thermal accounts for 71-72% annually (*refer to Table 1*).

The overall purpose of the research work in Texas therefore is to determine the cost of CO_2 capture from industrial anthropogenic sources and transporting the gas to oil fields for EOR activities and consequently boosting oil production and helping to reduce the CO_2 emissions in Texas and eventually the United States but with little or no significant losses in revenue and employment.

Specific objectives of thesis

The specific objectives of this thesis are to select the CO_2 emission source, the capture technology and analyse the physics of transporting the CO_2 fluid to the oil fields, then use the outcome to:

1. **Design** the CO_2 pipeline route (network)
2. **Estimate** the **total costs** of the CO_2 capture and the pipeline network.
3. **Determine** the **potential CO_2 emission** reduction to the atmosphere.
4. **Determine** the **impact of the CO_2 capture** on power generation cost.
5. **Estimate** the impact on employment creation.

All costs are in the United States dollars. The imperial system of inches would be maintained for diameters of pipeline in keeping with the general tradition of the industry.

Methodological steps

i. BEG provided a shortlist of oil fields located in Texas Gulf Coast which in its estimation, were best candidates for CO_2-EOR and eventually for sequestration.

ii. BEG also provided GIS map of all known industrial CO_2 sources in Texas.

iii. As a start, we regrouped the BEG selected oil fields (*over 50*) into 26 main CO_2-EOR candidate oil fields. *Main/largest fields serving as cluster point-fields.*

iv. We selected power plants as the CO_2 source since emissions from power plants are the most significant in Texas and in the United States.

v. We shortlisted all power plants with minimum CO_2 emissions of one (1) million tonnes per annum {*Reasons are provided elsewhere in Chapter Three of this thesis*}.

vi. We then superimposed the GIS maps of the power plants and that of the CO_2-EOR candidate oil fields and matched the power plants to the nearest oil fields.

vii. We finally selected power plants in and around Texas Gulf Coast with the potential to meet the CO_2 requirements of the CO_2-EOR candidate oil fields.

viii. Aided with the GIS maps, we selected the pipeline routes between the power plant (sources) and the oil fields (sinks), taking into consideration environmentally sensitive and restricted areas as well as large population centres.

ix. We designed the pipeline routes based upon the CO_2 mass flow rates from the power plants to the oil fields, the line-pipe sizes, compression pressures, and the distances between the sources and sinks.

x. We then linked the pipelines to form an integrated pipeline network, picking the CO_2 from multiple power plants and delivering to multiple candidate oil fields.

xi. Estimated the capital cost of the integrated pipeline network. We first tested the existing pipeline cost models by applying them to compute cost quotations submitted to Federal Electric Regulatory Commission (FERC) of the United States from 2006-2008 (FERC, 2009). We however found them to be challenging; unable to come close to the FERC compiled quotations.

xii. We therefore introduced cost escalation factors into selected pipeline models for the correction.

xiii. We used the corrected pipeline cost models to estimate the cost of our resulting pipeline network.

xiv. We reviewed CO_2 capture technologies and selected the capture technology for the power plants.

xv. We estimated the cost of CO_2 capture from the power plants.

xvi. We then analysed the percentage captures and the determined the impact on the generation costs on existing and proposed power plants in Texas Gulf Coast.

xvii. Finally, we estimated the number jobs likely to be created.

Scope and Limitation

The scope of research work was limited to Texas Gulf Coast (Figure 7).

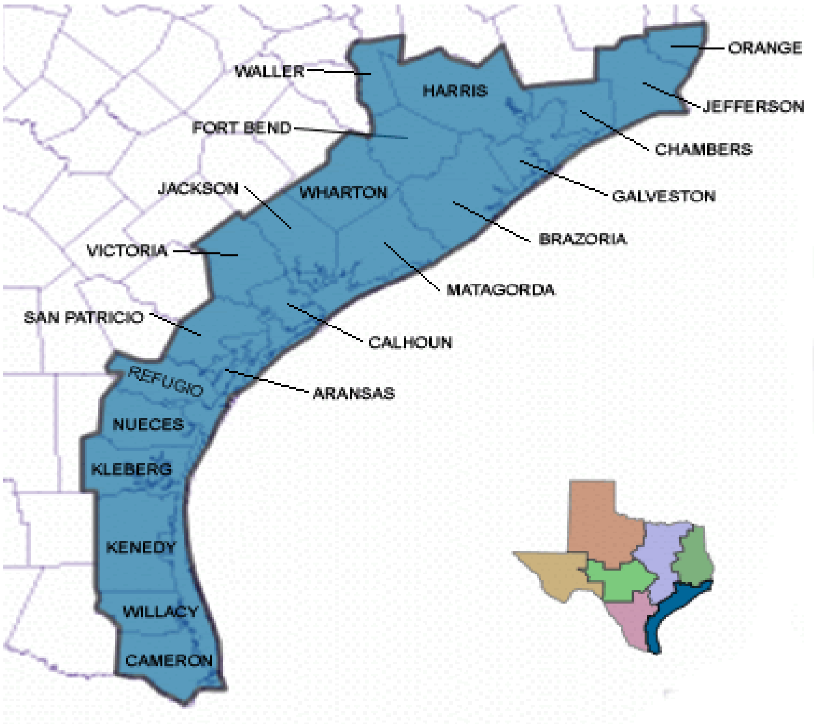

Figure 7. Map of Texas Gulf Coast. ***Names are the counties. (BEG, 2006a)***

The thesis would not cover or discuss the following areas:

- Public perception of the CO_2 pipeline project. A group at Duke University (Williams, Greenglass, & Ryals, 2007) is looking at such social issues.

- Environmental risks and uncertainties and issues related to potential water contamination since it is being looked at by another group at BEG (Duncan, Nicot, & Jong-Won Choi, 2009).
- Revenue streams and other economic indicators like royalties and taxes are exempted in this thesis.

Carbon Dioxide Capture

This thesis proposes to consider retrofitting of existing power plants with CO_2 capture technologies since it provides the most favourable economics in the short to medium term (1-5 years from today) as compared to constructing new power plant technologies.

The possibility of CO_2 capture from ambient air would not be discussed in this thesis {*CO_2 concentration in ambient air, around 380 ppm, a factor of 100 or more, lower than in flue gas and highly uneconomic to pursue with today's technology (IPCC, 2005)*}.

Pipeline

Only construction of new onshore pipeline is assumed. This thesis would not cover retrofitting of old or existing natural gas or any other sub-surface pipeline.

Relevance of Thesis

Between 26-30 billion tonnes of CO_2 are emitted globally each year and IPCC (2005) estimates that CCS could account for about 20% of the total CO_2 emission reductions needed to stabilise the climate during this century. However, without economic incentives such as EOR, the private investment community may not find it financially attractive to invest in CCS, since it may add considerable financial cost to their existing operations. EOR using CO_2 therefore may serve as an opportunity to develop the carbon market since the CO_2 becomes a commodity for pumping out more oil as EOR transit to complete CO_2 sequestration business in the nearest future.

With the significant commercial oil discovery in the deep offshore of Ghana in 2007, the country stands to boost and extend the lifespan of her oil production with EOR. The quality of the Jubilee field oil (API 35) suggests miscible CO_2–EOR is applicable. {*Miscible CO_2 for EOR is elaborated in Appendix 1}*. This research work could help estimate the infrastructural cost needed to transport the CO_2 from potential sources such as the natural gas processing plant proposed to be constructed at the nearest onshore (less than 200 km from the oil field), or the existing thermal power plant at Aboadze, near Takoradi in the Western Region of Ghana (B. Asante, personal communication, December 10, 2008).

An EOR operations proposed for the oil fields in Chad, illustrates the relevance of EOR in Africa. The cumulative oil production from the fields is estimated to be about 920 million barrels which is believed to be less than 30% of the total oil in the fields. CO_2-EOR could significantly boost the country's oil production (Huh & Lake, 2005).

Structure of Thesis

The thesis is structured into six chapters.

Chapter One has highlighted the big picture which is climate change, the science behind it, the link between thermal power plants and greenhouse gas emissions and consequently, climate change and its potential impact on global temperature rise as well as the international efforts to mitigate greenhouse gas emissions. The significance of the United States and Texas greenhouse gas emissions and potential of carbon capture and storage using EOR to mitigate the emissions have also been elaborated here.

Chapter Two covers literature review and theoretical framework of the carbon dioxide capture and the physics of carbon dioxide compressibility, transmission and miscibility with oil and its suitability for enhanced oil recovery.

Chapter Three covers the selection of the CO_2 sources and the carbon capture technology. Also, the analysis of the physics involved in modelling the pipeline network and transporting the fluid to the oil fields.

Whilst Chapter 3 covered the technical modelling, **Chapter 4** covers economic modelling of the CO_2 capture and transportation to the oil fields. In this thesis, the economic modelling would be limited to cost estimation of the infrastructure and its impact on electricity generation.

Chapter 5 discusses the results and the global significance of geologic carbon capture and storage whilst **Chapter 6** provides the conclusions and highlights the contributions to knowledge. Areas for future research are also proposed.

CHAPTER TWO

LITERATURE REVIEW AND THEORETICAL FRAMEWORK OF THE CARBON DIOXIDE CAPTURE AND TRANSPORT

Global Scan of Geologic Carbon Capture and Storage

Geologic carbon dioxide capture and storage (CCS) could reduce the impact of burning fossil fuel by capturing the CO_2 from fossil fuel sources, compressing it and injecting the compressed CO_2 into the geologic media (subsurface) for long-term storage. Sandstone rock formations have naturally trapped natural gases including CO_2 for over 20 million years (IPCC, 2005). The difference here in this thesis however is that industrial or anthropogenic CO_2 is considered rather than natural CO_2 in order to curtail the anthropogenic emission growth.

CCS is proposed as one of the wedges to help achieve the 45-80% reduction in the global CO_2 emissions by 2050 (Pascala & Socolow, 2004; IPCC, 2005).

There are a number of regional and inter-governmental initiatives that have been established to advance the CCS, capture technologies and the market development such as the IEA GHG Programme (IEA, 2009) and the European Union (EU) Zero Emission Power utilising CCS (Coleman, 2009). There were national projects to develop full-size pilot and commercial projects such as the FutureGen in the United States (FutureGen, 2006).

There are also industrial/research partnership initiatives formed among universities, research institutions and industry comprising largely petroleum, coal mining and power companies to advance CCS including the Regional Carbon Sequestration Partnership Program in the U.S., a collaborating network of more than 35 members comprising eight states, universities, energy companies, governmental and non-governmental agencies (Duke Energy, 2009).

A group in Europe is assessing CO_2 transportation cost from power plants to geologic formations in North Greece but not using EOR as a market catalyst (Koukouzas & Typou, 2009). There are other groups who are looking at other transportation options for transporting CO_2 for storage (Haugen et al., 2009) and developing algorithms for low-cost pipeline network (Kazmierczak, Brandsma, Neele, & Hendriks, 2009).

Another group at Duke University had looked at mitigating North Carolina (NC)'s electricity sector emissions using CCS since the sector is the state's biggest GHG emissions contributor (Williams et al., 2007). Coal contributes to about 98% of the electricity sector emissions and so the group proposed capturing the emissions from coal plants. Integrated Gasification Combined Cycle (IGCC) based on coal was considered due its superior conversion efficiencies over the conventional sub-critical coal plants. The group found CCS as uneconomic and not technically feasible within North Carolina due to limited geologic storage and high cost of CO_2 pipeline transport, but might be viable if the captured CO_2 is piped out of the state and stored say, in the Gulf Coast region, even though construction of a multi-state pipeline would be required. EOR was not considered in Duke's analysis.

IPCC (2005) estimates that CCS could account for about a quarter of the total CO_2 emissions reduction needed to stabilize the climate during this century and that about 10 trillion tonnes of CO_2 could be stored in secure geologic formations.

Table 3 shows some major large-scale on-going geologic storage of CO_2 projects. They are (Table 3) the Sleipner project in the North Sea; the Weyburn project in Canada; and the In Salah project in Algeria. In all three cases, the sources of CO_2 are from oil and gas field operations (IPCC, 2005).

Table 3. Geologic carbon sequestration sites as of 2005

Project Name	Country	Injection Start Year	Average daily injection rate (tCO_2 per day)	Total Storage tCO_2	Storage reservoir Type
Weyburn	Canada	2000	3,000-5,000	20,000,000	EOR
In Salah	Algeria	2004	3,000-4,000	17,000,000	Gas field
Sleipner	Norway	1996	3,000	20,000,000	Saline formation
K12B	Netherlands	2004	100	8,000,000	Enhanced gas Recovery (EGR)
Frio	U.S.A	2004	177	1600	Saline formation

Adapted from IPCC (2005).

CO_2 Supply network in Texas

In addition to the CCS projects currently in place, 30 million tonnes of CO_2 is injected annually for EOR, mostly in Texas, USA, where EOR commenced in the early 1970s. In the early 1970s, the Permian Basin oil reservoirs in Texas were starting to dry up to the point that producers decided to adopt tertiary recovery methods to enhance their oil production.

The first CO_2 project for EOR from a naturally occurring CO_2 which was being extracted from natural gas and otherwise vented into the atmosphere in West Texas was therefore developed. {*Naturally occurring CO_2 sources in Texas are from natural gas reservoirs with high content of CO_2*}. **Figure 8** shows the location of major oil fields in Texas.

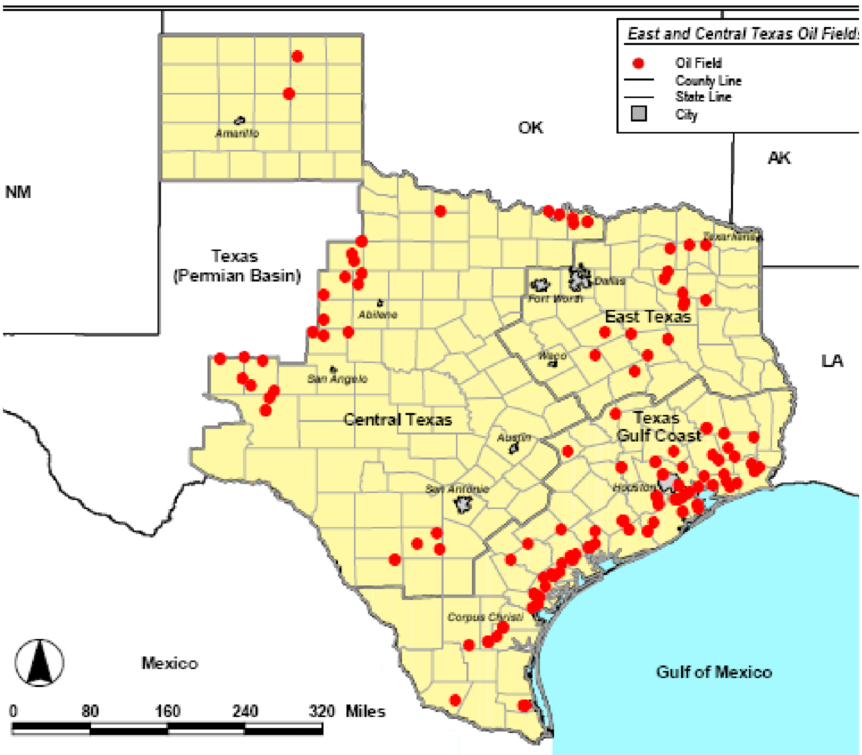

Figure 8. Locations of Major Oil Fields in Texas (*Advance Resource International, 2006*).

With the success of the first CO_2 flood and the many old fields to be flooded, demand for CO_2 grew so that large CO_2 pipelines were built to carry the naturally occurring CO_2 to the old (matured) fields for flooding in West Texas (BEG, 1999).

In summary, three large pipelines were built to carry CO_2 from natural sources (Figure 9) (BEG, 1999):

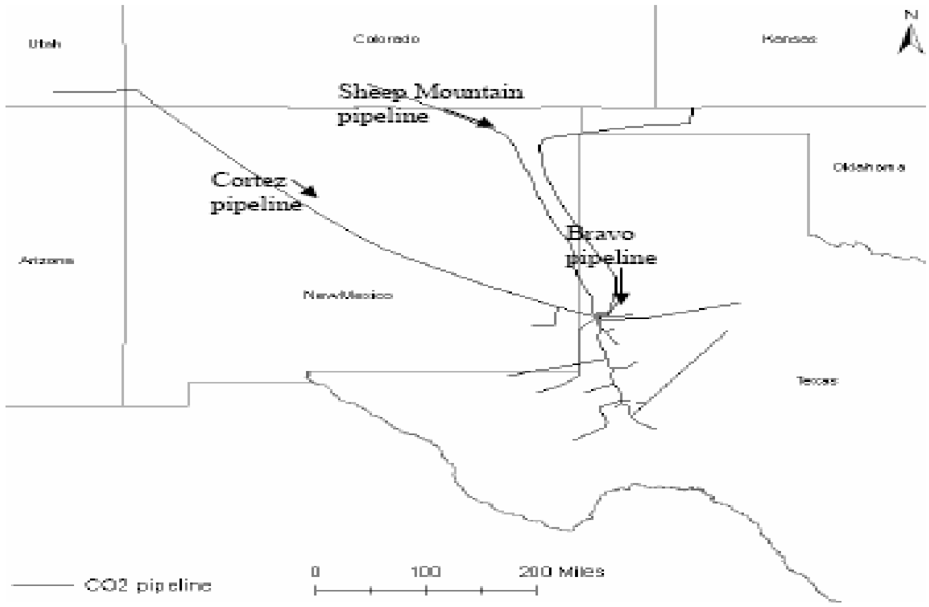

Figure 9. Major pipelines carrying CO_2 from natural sources to oil fields in Texas for EOR *Reproduced from BEG (1999).*

A 30-inch (76cm) -502 mile (808 km) pipeline named CORTEX with a capacity of 1-4 billion cubic feet per day (bscfd) (113-312 million cubic metres) of 98% pure CO_2 from Colorado.

- A 20-inch (51 cm) – 184 mile (296 km) pipeline named SHEEP MOUNTAIN with a carrying capacity of 330 mmcfd (9.35 mm cubic metres) of 97% pure CO_2 from south-central Colorado.
- A 20-inch (51 cm) – 210 mile (338 km) pipeline named BRAVO with a carrying capacity of 382 mmcfd (10.82 mm cubic metres) of 97% pure CO_2 from northeastern New Mexico State.
- The three major supply pipelines are joined into an integrated pipeline at Denver City in Texas.
- The CO_2 is then distributed through an outlet network comprising of more than four but smaller diameter pipelines to the oil fields.

The Bureau of Economic Geology (BEG) of the University of Texas at Austin has identified 745 oil fields that could be flooded with CO_2 for EOR, from a field with highest potential production of 213 million STB to one with a minimum potential production of 0.3 million STB using today's technology BEG (2006b).

Physics of Carbon Dioxide Compression and Transmission

Physical properties of carbon dioxide

Carbon dioxide is usually a gas in air at STP. {***STP*** *or* ***standard temperature and pressure*** *is a standard set of conditions for experimental measurements, to enable comparisons to be made between sets of data. Internationally, the current STP defined by the International Union of Pure and*

Applied Chemistry is an absolute pressure of 100 kPa (1 bar) and a temperature of 25 °C}.

Figure 10 shows the phase diagram of carbon dioxide.

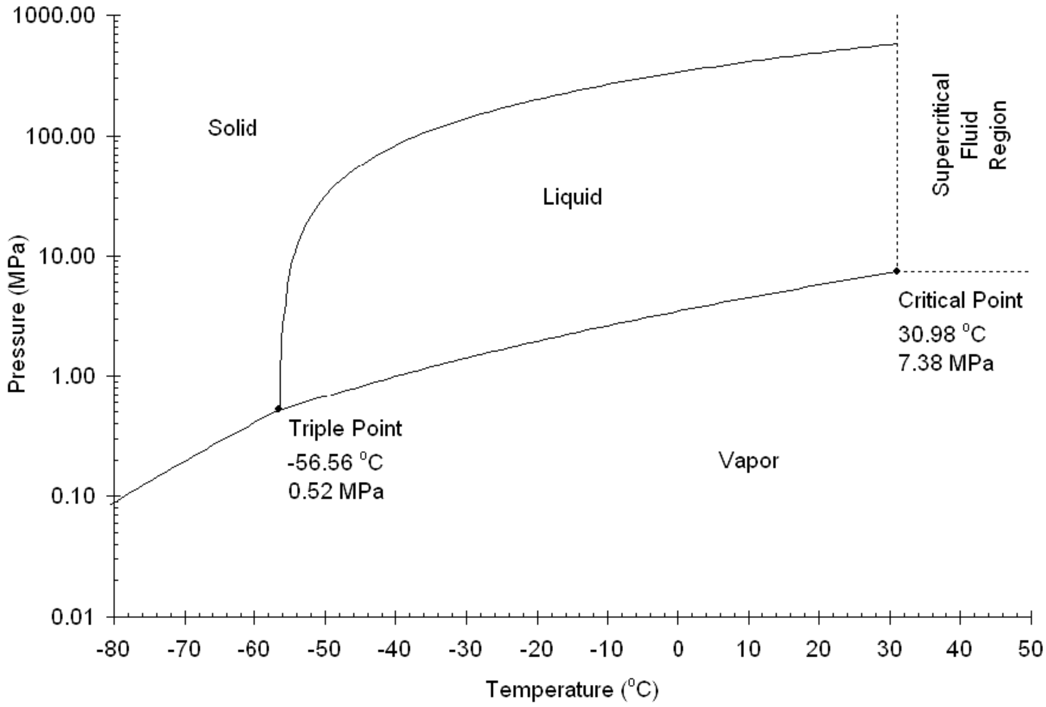

Figure 10. Phase diagram for Carbon dioxide (IPCC, 2005).

If the temperature and pressure are both increased from STP to be at or above the critical point for carbon dioxide, it can adopt properties midway between a gas and a liquid, more specifically, it becomes supercritical fluid above its critical temperature (31.1°C) and critical pressure (7.38 MPa or 73 atm), expanding to fill its container like a gas but with a density like that of a liquid.

Carbon dioxide transmission in gaseous phase results in multi-phase flow leading to high pressure losses, particularly in hilly terrains. The gas is therefore usually transported through a pipeline in liquid phase (Mohitpour, Golshan, & Murray, 2003). Also, production of solid CO_2 is highly energy sensitive whilst the density in the gaseous phase is too low for efficient transmission (Odenberger & Svensson, 2003).

For EOR or geologic storage, it is transported as a supercritical fluid since in this phase, the density and the viscosity of the CO_2 fluid approaches those of the residual oil. Also, the temperatures and pressures involved at about the same as those in the rock formations (Appendix 1).

Compressibility and transmission of carbon dioxide

The following equations would be used for the analysis of the carbon dioxide compression and transport (transmission) through the pipeline. They are

$$\boldsymbol{PV = nZRT} \qquad \textbf{(1)}$$

which is the equation of state for real gas, where ***P*** *is the pressure acting on the gas; V is the volume of the gas;* ***Z*** *is the compressibility factor of the gas;* ***R*** *is the gas constant, n is defined as* $n = \frac{m}{M}$***,*** ***m*** *is the mass of the gas flowing in the pipeline and* ***M*** *is the average molecular mass of the gas.*

We considered supercritical CO_2 fluid of density **(ρ)** and mass **(m)** flowing with a velocity **(υ)** through an **open** pipeline of length **(L)**; diameter **(D)**, cross-sectional area **(A)** with **inlet (1)** and **outlet (2)**, tilted at an infinitesimally angle ***α≈dH/dL.*** Assuming amount of work ***dW*** and heat ***dQ*** crossing the system boundaries 1 to 2 (Figure 11).

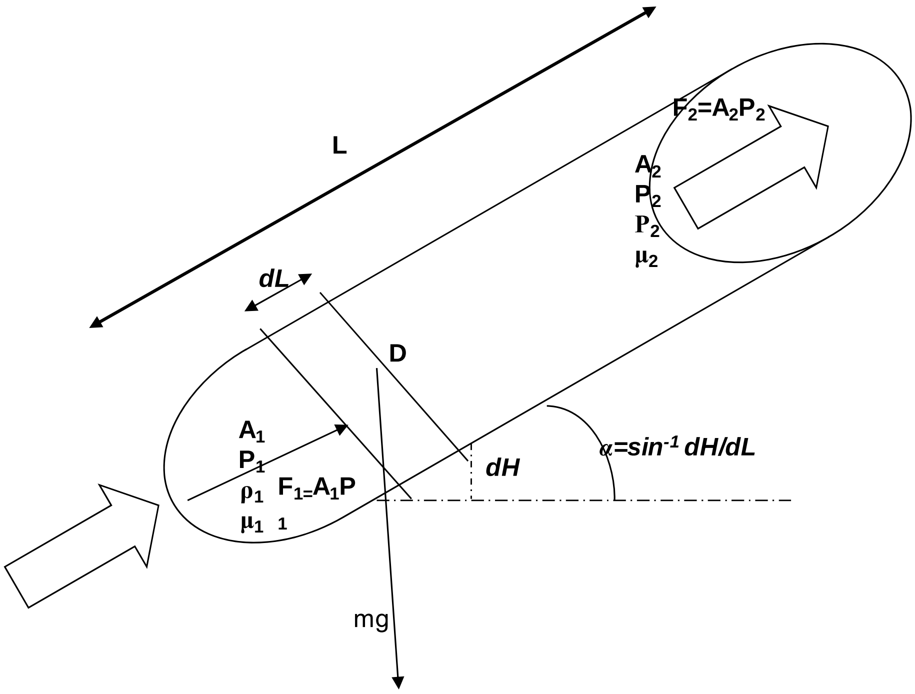

Figure 11. Steady state flow of CO_2 in an open pipeline

The mass flow rate of the gas at the inlet is equal to the mass flow rate of the gas at the outlet of the pipeline which is continuity equation and is constant, i.e.

$$\rho_1 A_1 \upsilon_1 = \rho_2 A_2 \upsilon_2 = const \qquad \textbf{(2)}$$

From the Newton's Law of Motion, the rate of change of momentum is equal to the external force **F,** i.e.

$$F = \frac{d}{dt}(\rho A \upsilon) \qquad \textbf{(3)}$$

Also, $F = m.a$

Where $a = d\upsilon / dt$ *is the acceleration of the gas particle in the pipeline.*

$$dF = \frac{d\upsilon}{dt}.dm = \frac{d\upsilon}{dt}.\rho.A.dy = \rho.A.d\upsilon.\frac{dy}{dt}$$

$$dF = \rho.A.\upsilon.d\upsilon$$

$$dm = \rho.A.dy$$

$$\frac{dy}{dt} = \upsilon$$

Assuming the particle of the CO_2 gas is being impacted by all existing classical forces, i.e. pressure, mass, friction, etc. as follows: $\mathbf{F_1}$, $\mathbf{F_2}$, $\mathbf{F_3}$, and $\mathbf{F_4}$ (Figure 12)

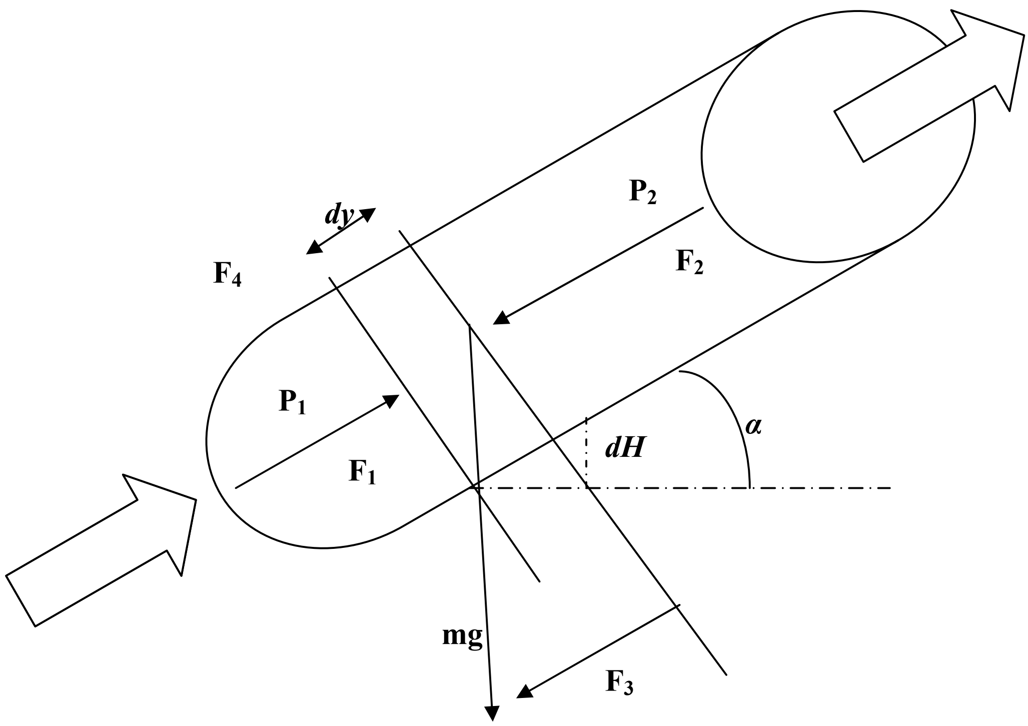

Figure 12. Forces acting on a gas particle moving in an inclined pipeline

where:

F_1** is the force acting on the gas particle due to the gas pressure **P_1

F_2** is the force acting on the gas particle due to the gas pressure **P_2

F_3** is the force exerted on the gas particle due to the mass **m

***F_4** is the force acting on the gas particle due friction.*

Then in accordance with Bernoulli equation, the **summation** of all the forces should **equal to zero,** i.e. (Mohitpour et al., 2003):

$$\mathbf{F_1, + F_2, + F_3, + F_4} = 0 \qquad \textbf{(4)}$$

where the forces are defined as:

$F_1 = AP_1$	in differential form, it is	$dF_1 = AdP_1$
$F_2 = AP_2$	in differential form, it is	$dF_2 = AdP_2$
$F_3 = mg \sin \alpha$	in differential form, it is	$dF_3 = d(mg) \sin \alpha$

F_4= surface area * shear stress

Law governing the supercritical fluid flow

The First Law of Thermodynamics for non-flow closed system (*also known as law of Conservation of Energy*), states that a *change in the internal energy of the closed system ΔU is equal to the difference between the heat supplied Q and the work done W on the system* (Akuffo, Brew-Hammond, Luti, & Massaquoi, 1997):

$$\Delta U = Q - W \qquad \textbf{(5)}$$

However, for an **open** and **energy flow system** such as an **open CO_2**

pipeline, the energy, the heat flow and the work done on the system will be changing with time***, t,*** i.e.

$$\frac{dQ}{dt}, \frac{dW}{dt}, \frac{dE}{dt}$$

The flow is therefore governed by the **1st law of thermodynamics for an open system** (Akuffo et al, 1997)

$$\frac{dQ}{dt} - \frac{dW}{dt} = \frac{dE}{dt} + \sum_{outlet} \frac{dm_2}{dt}\left(H_2 + \frac{1}{2}\upsilon_2^2 + gL_2\right) - \sum_{inlet} \frac{dm_1}{dt}\left(H_1 + \frac{1}{2}\upsilon_1^2 + gL_1\right) \qquad \textbf{(6)}$$

For supercritical CO_2 fluid (Temp T≥31 ^oC), Press ≥7.38MPa), and aassuming a **steady- state steady-flow** process, constant with time, **mass flow rate** is **constant:** $\frac{dm_1}{dt} = \frac{dm_2}{dt} = \frac{dm}{dt}$

Therefore, total energy **(E)** of system must be constant, i.e.

$$\frac{d(E_1 - E_2)}{dt} = \frac{dE}{dt} = 0$$

$$\frac{dQ}{dt} - \frac{dW}{dt} = const$$

Equation 6 reduces to

$$\frac{dQ}{dt} - \frac{dW}{dt} = \frac{dm}{dt}(H_2 - H_1) + \frac{1}{2}\frac{dm}{dt}\left(\upsilon_2^2 - \upsilon_1^2\right) + g\frac{dm}{dt}(L_2 - L_1) \qquad \textbf{(7)}$$

Simplifying E**quation 7** by canceling ***dt*** yields the 1st law of thermodynamics for **steady-flow** is:

$$gdm(L_2 - L_1) + \frac{1}{2}dm(\upsilon_2^{\ 2} - \upsilon_1^{\ 2}) + dm(H_2 - H_1) = dQ - dW \qquad \textbf{(8)}$$

The steady-flow energy equation of 1st law of thermodynamics is same as Bernoulli's equation for ideal fluids (Serway & Faughn, 1995):

$$P + \frac{1}{2}\rho v^2 + \rho g \Delta H = const \qquad \textbf{(9)}$$

Pressure	+	**Kinetic Energy per unit volume**	+	**Potential Energy per unit volume**	=	**const**

For real fluids however, there is frictional loss and the Bernoulli's equation **(**Equation 9**)** is expressed as

$$P + \frac{1}{2}\rho v^2 + \rho g \Delta H + \frac{1}{A}\pi D \tau \int_1^2 dL = 0 \qquad \textbf{(10)}$$

Where the fourth term in **Equation 10** is the friction loss and is defined as the product of **surface area** ***A*** of the pipeline and **shear stress τ**.

*The shear stress **τ** is defined as*

$$\tau = f.\frac{1}{D}.\frac{u^2}{2}dL \qquad \textbf{(11)}$$

*where **u** is average gas velocity, **f** is friction factor, **D** is pipeline diameter and **dy**=**L** is pipeline length.*

Another form of expression of the Bernoulli equation is (Mohitpour et al, 2003):

$$\frac{C^2}{g_c}\int_1^2 \frac{1}{u}.du + \frac{M}{Z_{ave}.R.T_{ave}}\int_1^2 PdP + \int_1^2 \left(\frac{P.M}{Z.R.T}\right)^2 dH + \frac{2fC^2}{g_c D}\int_1^2 dL = 0 \qquad \textbf{(12)}$$

where the:

First term is the kinetic energy

Second term is the total internal energy due to pressure on the system; we would call it Pressure Energy

Third term is the Potential energy

Fourth term is the friction loss.

The final form of the Bernoulli equation is obtained by integrating each term of the **Equation 12**.

Kinetic Energy Term

$$\int_1^2 \frac{1}{g_c}\frac{u}{v^2}du = \int_1^2 \frac{1}{g_c}\frac{u}{v}\frac{du}{v} \tag{13}$$

$C = \frac{v}{A}$

$$\frac{C}{g_c}\int_1^2 \frac{C}{u}du = \frac{C^2}{g_c}\int_1^2 \frac{1}{u}du$$

Thus

$$Kinetic.energy = \frac{C^2}{g_c} In\frac{u_2}{u_1} \tag{14}$$

Pressure Energy Term

$$\int_1^2 \frac{dP}{v} = \int_1^2 \rho dP \tag{15}$$

$\rho = \frac{m}{V}$

From **Equation 1**

$$\rho = \frac{P.M}{Z.R.T} \qquad \textbf{(16)}$$

Substituting **Equation 16** into right hand side of **Equation 15,** we have:

$$\int_1^2 \frac{dP}{v} = \int_1^2 \frac{PM}{ZRT} dP$$

$$\int_1^2 \frac{P.M}{Z.R.T} dP = \int_1^2 \frac{M}{Z_{ave}.R.T_{ave}} PdP = \frac{M}{Z_{ave}.R.T_{ave}} \int_1^2 PdP$$

Therefore the $\text{Pressure.energy} = \dfrac{M}{Z_{ave}.R.T_{ave}} . \dfrac{P_2^2 - P_1^2}{2}$ **(17)**

where Z_{ave} and T_{ave} are the average compressibility factor and temperature respectively.

$$T_{ave} = \frac{T_1 + T_2}{2}$$

T_1 and T_2 are the upstream and downstream gas temperatures.

Potential Energy Term

$$\int_1^2 \left(\frac{P.M}{Z.R.T} \right)^2 dH \qquad \textbf{(18)}$$

The potential energy term becomes:

$$Potential.energy = \frac{P_{ave}^2 .M^2}{Z_{ave}^2 .R^2 .T_{ave}^2} \Delta H \qquad \textbf{(19)}$$

where $\boldsymbol{\Delta H = H_2 - H_1}$

Friction Loss Term

$$\frac{2fC^2}{g_c D}\int_1^2 dL \tag{20}$$

Where ***L*** *is the length of the pipeline.*

From **Equation 20**, the friction loss term becomes:

$$Friction.loss = \frac{2fC^2}{g_c D} L \tag{21}$$

Summing **Equations 14, 17, 19** and **21** provides the final form of the Bernoulli equation governing the flow of the CO_2 gas in a pipeline as:

$$\frac{C^2}{g_c} In\frac{u_2}{u_1} + \frac{M}{2RZ_{ave}.T_{ave}}(P_2^2 - P_1^2) + \frac{M^2.P_{ave}^2}{R^2.T_{ave}^2.Z_{ave}^2}\Delta H + \frac{2fC^2}{g_c D}L = 0 \tag{22}$$

For CO_2 being transmitted under supercritical condition, $\mu_1 = \mu_2$ (Mohitpour et al., 2003). Therefore **Equation 22** for supercritical flow becomes:

$$\frac{M}{2RZ_{ave}.T_{ave}}(P_2^2 - P_1^2) + \frac{M^2.P_{ave}^2}{R^2.T_{ave}^2.Z_{ave}^2}\Delta H + \frac{2fC^2}{g_c D}L = 0 \tag{23}$$

Calculation of the internal diameter of the pipeline

Upon substitution and rearrangement to solve for D, other workers have reduced **Equation 23** further to **Equations 24** to calculate the internal diameter of the pipeline $\boldsymbol{D_I}$, as by Mohitpour et al. (2003):

$$D_i^5 = f_F * \left(\frac{32.V^2.M^2.P^2}{\pi^2 R.T_b^2 Z_b^2} \right) * \left(\frac{58 Z_{ave} T_{ave}.G.L}{P_1^2 - P_2^2 - \dfrac{58 G.\nabla H.P_{ave}^2}{R.T_{ave}.Z_{ave}}} \right). \quad \textbf{(24)}$$

and by McCoy (2008)

$$D_i = \left\{ \frac{-64 Z_{ave}^2 R^2 T_{aveF}^2 \dot{m}^2 L}{\pi^2 \left[M Z_{ave} R T_{ave} \left(p_2^2 - p_1^2 \right) + 2 g P_{ave}^2 M^2 \left(h_2 - h_1 \right) \right]} \right\}^{1/5} \quad \textbf{(25)}$$

Where L is the length of the pipe segment; f_F *is the fanning friction factor; R is the ideal gas constant;* P_{ave} *is the average pressure, H is height* T_{ave} *is average temperature of flowing* CO_2 *over the entire pipeline length.*

Figure 13 is the resulting graph from **Equation 25**.

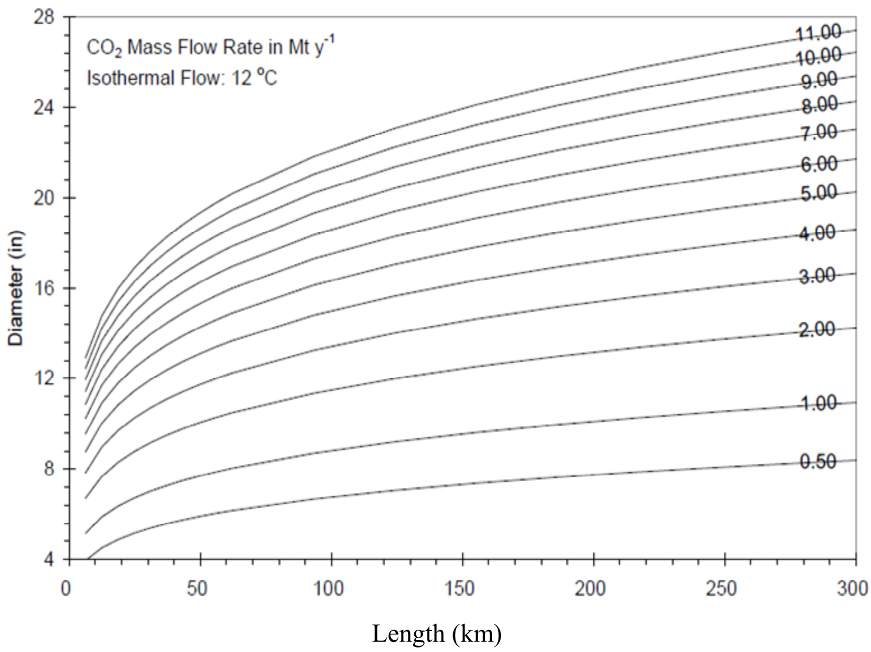

Figure 13. Line-pipe sizes (diameters) as a function of length at given flow rates in million tonnes per year (Mt/y)

Types of flow regimes

Supercritical flow is high pressure gas transmission. Two types of flow regimes are normally observed depending upon the flow rates:

- Fully turbulent flow (rough pipe flow)
- Partially turbulent flow (smooth pipe flow)

The regime of flow is defined by the Reynolds number, **Re**, defined as

$$\mathrm{Re} = \frac{\rho . D . u}{\mu} \tag{26}$$

If ***Re*< *2000***, the flow is normally laminar, or stable. For ***Re* > *2000***, flow is turbulent, or unstable. ***Re*** is dimensionless.

*Where **μ** is fluid viscosity.*

Partially turbulent flow regime

Partially turbulent flow is defined by the Prandtl–Von Karman equation (Mohitpour et al., 2003):

$$\sqrt{\frac{1}{f}} = 4 \log_{10} \frac{\mathrm{Re}}{\sqrt{\frac{1}{f}}} - 0.6 \tag{27}$$

where $\sqrt{\frac{1}{f}}$ *is the transmission factor,* ***f*** *is friction factor and it is dimensionless*.

Fully turbulent flow regime

The transmission factor for fully turbulent flow is given by the Nikuradse equation as follows (Mohitpour et al., 2003):

$$\sqrt{\frac{1}{f}} = 4\log_{10}\left[3.7\frac{D}{K_e}\right] \tag{28}$$

Where $\frac{Ke}{D}$ *relative roughness and dimensionless,* $\boldsymbol{K_e}$ *is effective roughness.*

$$Ke = Ks + Ki + Kd \tag{29}$$

Where K_s *= surface roughness;* K_i *= interfacial roughness;* K_d *= roughness due to bends, welds, fittings, etc.*

Overview of CO_2 source types and Capture Technologies

CO_2 source types

The CO_2 emissions by fossil fuel power plants and furnaces are typically described as large stationary sources, to distinguish them from mobile sources such as vehicular transport and from smaller stationary sources such as small individual or decentralised heating boilers, cooking stoves and portable power generation sets used in homes.

IPCC (2005) considered large stationary sources as those emitting over 100,000 tonnes of CO_2 (0.1 $MtCO_2$) per year, because sources emitting less than 0.1 $MtCO_2$ per year together account for less than 1% of the total emissions from all the stationary sources worldwide.

Stationary power plants were therefore opted for as sources of the CO_2 supply for the EOR.

Combustion based CO_2 emissions

These CO_2 emissions result from the oxidation of carbon when fossil fuels are burned. These emissions are associated with fossil fuel combustion in power plants, oil refineries and large industrial facilities.

Feedstock-based CO_2 emissions

Carbon dioxide not related to combustion is emitted from a variety of industrial production processes which transform materials chemically, physically or biologically. Such processes include:

- the use of fuels as feedstocks in petrochemical processes (Chauvel & Lefebvre, 1989);
- the use of carbon as a reducing agent in the commercial production of metals from ores (IEA, 2000a; IPCC, 2005);
- the thermal decomposition (calcination) of limestone and dolomite in cement or lime production (IPCC, 2005); and
- the sugar-alcohol production (e.g., to convert sugar to alcohol).

Gas fields based CO_2 emissions

A third type of source occurs in natural-gas processing installations. CO_2 is a common impurity in natural gas, and it must be removed to improve the heating value of the gas or to meet pipeline specifications (Maddox & Morgan, 1998). This has been the source of natural CO_2 for the EOR activities in West Texas.

Multi-source CO_2 emissions

Some industrial-processes like aluminium production produce CO_2 emissions during the chemical reactions as well as combustion of fuels and the consumption of the electrodes (IEA GHG, 2000b).

CO_2 concentration and partial pressure

Another important factor in selecting a source of CO_2 for the capture is the partial pressure of the CO_2 in the emissions or sources. The rule of thumb is that the higher the partial pressure of the gas stream the less stringent the conditions for separating the CO_2 from the gas. **Table 4** therefore also includes partial pressures of the sources.

Typical emission sources from the power sector and from industrial processes have low CO_2 partial pressures. Where emission sources with high partial pressure are generated, for example in ammonia or hydrogen production, these sources require only dehydration and some compression and therefore they can have lower capture costs.

78% of all large stationary CO_2 emission sources emanate from power plants, 20% from gas processing and the remainder from iron and steel plants (IPCC, 2005).

Table 4 presents the CO_2 concentrations in the sources mentioned above.

Table 4. Sources of CO_2 emissions, the gas stream and partial pressures involved.

Source	**CO_2 Concentration % volume (dry)**	**Pressure of gas stream MPa**	**CO_2 partial pressure MPa**
CO_2 from fuel combustion			
Flue gas:			
Natural gas boilers	*7-10*	*0.1*	*0.007-0.010*
Gas turbines	*3-4*	*0.1*	*0.003-0.004*
Oil-fired power plants	*11-13*	*0.1*	*0.011-0.013*
Coal fired power plants	*12-14*	*0.1*	*0.012-0.014*
Oil Refinery	8	0.1	0.008
CO_2 from chemical reactions			
Ammonia production	18	2.8	0.5
Hydrogen production	15-20	2.2-2.7	0.3-0.5
CO_2 from chemical reactions + fuel combustion			
Blast furnace:			
Before combustion	*20*		*0.040-0.060*
After combustion	*27*		*0.027*
Cement kiln off-gas	*14*		*0.014-0.033*
CO_2 from other processes			
Natural gas processing	2-65	0.9-8	0.05-4.4

Adapted from IPCC (2005)

CO_2 capture technologies

The main capture technologies could be grouped into four categories, Pre-combustion, Post-combustion, Oxyfuel combustion and Industrial Process streams (IPCC, 2005).

Pre-Combustion

This is a process of separating the CO_2 from the primary fuel before combustion. Separate streams of CO_2, and hydrogen (H_2) are produced from the fuel. The CO_2 is then captured whilst the hydrogen stream is used as fuel.

A primary fuel is reacted with either steam or oxygen to chemically decompose the fuel and produce synthesis gas (syngas) comprising largely hydrogen (H_2,) and carbon monoxide (CO). The syngas is then processed further to convert the CO to CO_2 and increases the CO_2 and H_2 mole concentrations to approximately 40% and 55% respectively. At this point, the CO_2 has a high partial pressure which improves the driving force for separation. More so, the higher the CO_2 concentration the less expensive to capture.CO_2 is removed, usually by a physical or chemical absorption process (IPCC, 2005).

After CO_2 removal, the H_2-rich syngas is purified and used to feed a turbine for electricity generation, or boiler for thermal power or as transport fuel. Pre-combustion capture thus requires a chemical scrubbing plant *in front of* the turbine (IPCC, 2005).

Post-Combustion

The principle of post-combustion capture is separation of CO_2 from flue gases emanating from thermal power and industrial combustion plants. Thus in contrast to pre-combustion process, a chemical scrubbing plant is placed after the combustion of the fuel (or turbine in case of electricity generation).

Oxyfuel -Combustion

Oxy-fuel combustion uses oxygen instead of air for fuel combustion, producing a flue gas which is mainly water (H_2O) and CO_2. The CO_2 content of the (dry) flue gas varies from 70% to above 95% depending on the fuel, the process used, the air in-leakage and the O_2 purity (IPCC, 2005).

Industrial Process-Streams

Examples of CO_2 capture from process streams are purification of natural gas and production of hydrogen-containing synthesis gas for the manufacture of ammonia, alcohols and synthetic liquid fuels. Other industrial process streams which are sources of CO_2 but not captured include cement and steel production, and fermentation processes for food and drink production (IPCC, 2005).

Post combustion capture technologies

There are three available process technologies which could in principle be used to capture CO_2 from flue gases of power plants, namely (IPCC, 2005):

- **Absorption process** where the CO_2 capture is accomplished through separation with sorbents/solvents.
- **Membrane process** where CO_2 is selectively removed from a gaseous stream using membranes made up of polymeric and metallic ceramics.
- **Liquefaction and distillation** process where CO_2 is removed through a cycle of compression and distillation.

Of the three, the lead contending technology is *absorption process* based on solvent scrubbing using amine solvents currently mainly monoethanolamine

(MEA). Advantages of amine scrubbing for post-combustion capture are that it can be retrofitted to existing power plants and industries in suitable locations, and it has been the most commercially proven at present. Furthermore, amine is suitable for low CO_2 partial pressures as occur in flue gas of power plants *(refer to Table 4)*.

The negative aspect of the amine technology however is said to be its large size. The higher the CO_2 capture the greater the height of the absorption vessels. Research has therefore expanded to cover other chemical solvents (Amann & Bouallou, 2009). Tigges et al., (2009) are looking at oxyfuel as attractive option for retrofit applications, since it appears not to have major impact on the boiler-turbine steam cycle and thus reduces the technical risk of implementing new components and processes not yet proven in the power sector.

There is also an ammonia based absorption but it is less commercial and consequently, of a higher economic risk at present (IPCC, 2005).

Amine absorption capture

The typical flow sheet of CO_2 recovery using chemical absorbents is shown in **Figure 14** (IPCC, 2005). The flue gas from the power plant containing the CO_2 is cooled first and is washed to remove fly-ash and soot present in it before bringing into contact with the amine, else they can clog the absorber. The CO_2 is bound by the chemical solvent – amine. A blower (fan) pumps the gas through the absorber. At temperatures typically between 40-60^{o}C, CO_2 is then bound by the chemical absorbent in the absorber. After passing through the absorber the flue gas undergoes a water wash section to balance water in the system and to remove any droplets or vapour carried over and then leaves the absorber. Sulphates are in the flue gas and concentrations range from 300-5000 ppm but are removed using scrubbers by 98-99%. Amine works effectively for SOx concentrations of around 10 ppm. To minimize solvent (amine) consumption, SOx is further removed up to 1-2 ppm level. Lower levels of SOx removal however calls for increasing the absorber tower which is at a significant cost. Thus the optimal sulphate content before CO_2 absorption process is a trade-off between CO_2 solvent consumption and SO_2 removal costs (IPCC, 2005). The "rich" absorbent solution, which contains the chemically bound CO_2 is then pumped to the top of a stripper, via a heat exchanger (Figure 14).

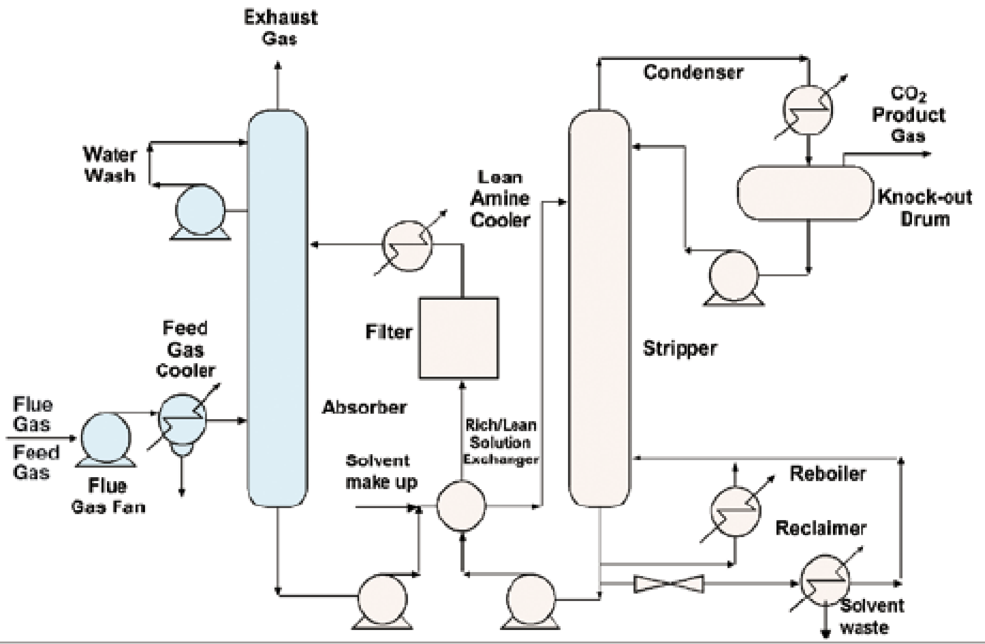

Figure 14. Process flow diagram for CO_2 capture from flue gas with chemical absorbents (IPCC, 2005)

The regeneration of the chemical absorbent is carried out in the stripper at elevated temperatures (100–140^{o}C) via steam. Steam is recovered in the condenser and fed back to the stripper, whereas the CO_2 product gas leaves the condenser. The CO_2-product is a relatively pure (> 99%) product, with water vapour being the main other component (IPCC, 2005).

The flue gases are usually above 100^{o}C and so have to be cooled down to temperature levels required for efficient absorption of CO_2 by the sorbent. The CO_2 loaded solvent is transported to a different vessel where it releases the CO_2 after being heated and/or after a pressure decrease (*refer to Figure 14*).

A make-up flow of fresh sorbent is always required to compensate for the natural decay of activity and/or sorbent losses. Flow of sorbent between the vessels is large because it has to match the huge flow of CO_2 being processed in the power plant. Therefore equipment sizes and the energy required for sorbent regeneration are large and tend to translate into an efficient penalty and added cost.

Purity and pressure of CO_2 typically recovered from an amine-based chemical absorption process are about 99.9% by volume (water saturated conditions).

The higher the CO_2 capture the greater the height of the absorption vessels (column), the higher the energy penalties and hence increased costs.

In addition, a chemical base largely sodium hydroxide (NaOH) is used to reclaim the amine (typically 0.03 – 0.13 kg NaOH / tCO_2) (IPCC, 2005).

Activated charcoal is used to remove decomposition products from the amine (typically 0.03-0.06 kg activated carbon per tonne CO_2) (IPCC, 2005).

Carbon dioxide compression and pump power requirements

The equation for the compression ratio (CR) for N stages of compression is given by (Mohitpour et al., 2003) {*Assuming equal work done per stage*}:

$$CR = (\frac{Pcut - off}{Pinitial})^\wedge(\frac{1}{Nstage}) \tag{30}$$

The compression power (kW) requirement for each stage $W_{i,s}$ is also given by (Mohitpour et al., 2003):

$$W_{s,t} = \left(\frac{1000}{24x3600}\right)\left(\frac{mZ_s RT_{in}}{M\eta_{is}}\right)\left(\frac{k_s}{k_s - 1}\right)\left[(CR)^{\frac{k-1_s}{k_s}} - 1\right] \tag{31}$$

Where:

$W_{s,I}$ = *compression power requirement for each individual stage [kW]*

$P_{initial}$ = *initial pressure of CO_2 directly from capture system [MPa]*

P_{final} = *final pressure of CO_2 for pipeline transport [MPa]*

$P_{cut\text{-}off}$ = *pressure at which compression switches to pumping [MPa]*

N_{stage} = *number of compressor stages*

CR = compression ratio of each stage

Z_s = *average CO_2 compressibility for each individual stage*

T_{in} = *CO_2 temperature at compressor inlet [K]*

η_{is} = *isentropic efficiency of compressor*

R = Universal Gas Constant

k_s = (C_p/C_v) = average ratio of specific heats of CO_2 for each individual stage

$W_{s\text{-}total}$ = total combined compression power requirement for all stages [kW]

For all stages (Mohitpour et al., 2003) the following constants were used for the Texas Gulf Coast:

R = 8.314 kJ/kmol-K;

M = 44.01 kg/kmol;

T_{in} = 313.15 K (i.e., 40 ^{O}C); to ensure fluid travels at longer distances even during cold seasons before another stage of compression.

η_{is} = 0.75; average recommended value (Mohitpour et al., 2003).

1000 = number of kilogrammes per tonne.

24 = number of hours per day;

3600 = number of seconds per hour

To solve **Equation 31**, N times calculations is conducted for the number of compression stages and the total $\mathbf{W_{total}}$ is given by

$$\mathbf{W_{total} = W_{s1} + W_{s2} + W_{s3} + \ldots\ldots + W_{sN}} \qquad \mathbf{(32)}$$

Where W_{s1}, W_{s2}, W_{s3}, W_{sN} are compression power requirements for stages 1, 2, 3 and N respectively in [kW]

The maximum size power of one compressor train since 2002 is 40,000 kW (IEA, 2002). For a total compressor power requirement greater than 40,000 kW, the CO_2 flow rate and total power requirement are split into $\boldsymbol{N_{train}}$ parallel compressor trains, each operating at $100/N_{train}$ % of the flow/power.

$$N_{train} = \frac{W_{total}}{40{,}000} \quad \textbf{(33)}$$

Where Ntrain =number of parallel compressor trains and an integer.

The pumping power requirement for boosting the CO_2 pressure from $P_{cut\text{-}off}$ to P_{final} is given by the equation:

$$Wp = (\frac{1000*10}{24*36})[\frac{m(Pfinal - Pcutoff)}{\rho\eta} \quad \textbf{(34)}$$

Where

W_P = pumping power requirement [kW]

ρ = density of CO_2 during pumping [kg/m3], η = efficiency of pump.

CHAPTER THREE

TECHNICAL MODELLING OF THE CARBON DIOXIDE CAPTURE AND TRANSPORTATION

This chapter covers the selection process for the CO_2 source, capture technology and the pathway for the pipeline to transport the CO_2 from the sources to the oil fields (sinks). Justification for selecting power plants as the CO_2 source is discussed. The parameters used in modelling the pipeline network and the CO_2 capture plant are elaborated. The proposed pipeline network is also presented.

Selecting the Carbon Dioxide Source and Capture Technology

Shortlisting the CO_2 – EOR Candidate Oil fields

For this thesis, BEG provided a shortlist of 33 candidates from a field with highest potential oil production of 213 million STB and cutting off at 13 million STB potential production.

The BEG shortlist was regrouped according to fields of the same characteristics. Also, close-by minor fields (within the catchment of bigger fields) were regrouped under their major fields. In this case the fields were reduced to 26 major oil fields covering 114 reservoirs (Appendix 1). The locations of the fields are shown in **Figure 15**.

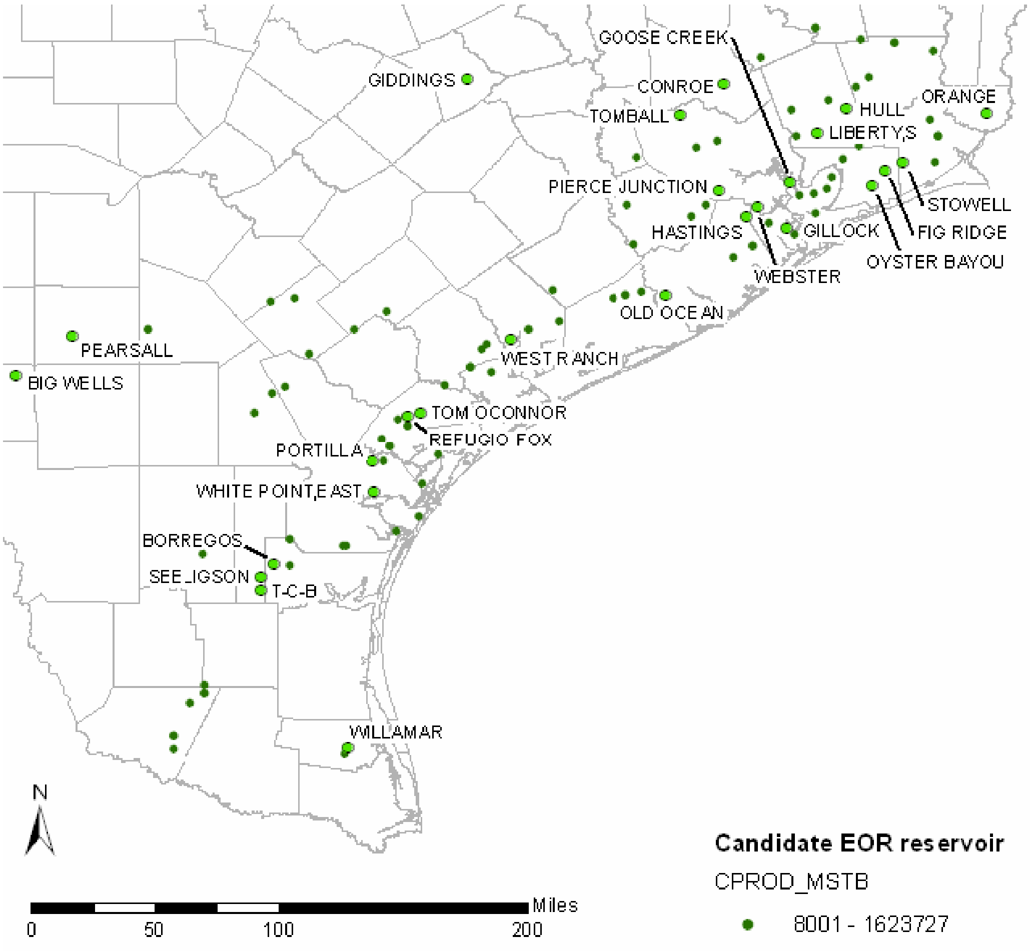

Figure 15. Map of Texas Gulf Coast showing the large EOR candidate oil fields (BEG, 2006)

These fields represent almost 60% of the estimated original-oil-in-place (EOOIP) and in the Texas Gulf Coast. . A snapshot of the BEG CO_2-EOR candidate fields is as follows:

- Estimated original oil in place (OOIP) 11.6 billion barrels
- Cumulative production as of 2006 5.7 billion barrels

• Total potential technically recoverable oil through EOR.	1.7 billion barrel
• CO_2 required for EOR	224 million tonnes
• Total CO_2 that can be stored before EOR	587 million tonnes
• Total CO_2 that can be stored after EOR	729 million tonnes

Table 5 estimates the annual CO_2 emissions per barrel of oil burnt in the United States.

Table 5 CO_2 emissions from petroleum consumption in the U.S.

	2004	**2005**	**2006**	**2007**	**2008**
Petroleum consumption per year (365 days) in barrels	7,566,870	7,592,789	7,550,908	7,548,338	7,116,757
Carbon dioxide emissions per annum in million tonnes	2,603	2,620	2,596	2,580	2,581
Emissions tCO_2/bbl	**0.34**	**0.35**	**0.34**	**0.34**	**0.36**

Source: US EIA, 2008

Using an average of about 0.34 tonnes carbon dioxide is emitted per barrel of oil burnt, additional 578 million tonnes CO_2 could be emitted to the atmosphere from the estimated 1.7 billion barrels recoverable oil, (assuming if all the oil is burnt) but that could also be stored in the rock spaces created after the EOR is completed, provided sequestration is continued. *Assuming economic lifetimes of 20 and 25 years for the EOR activities, dividing CO_2 requirements by 20 and 25 years yield the annual requirements (Table 6).*

Table 6: Major oil fields and their CO_2 requirements for EOR and sequestration

MAIN OIL FIELDS AND CATCHMENTS (number of minor fields in brackets)	CO_2 REQUIREMENTS FOR ENHANCED OIL RECOVERY AND GEOLOGIC SEQUESTRATION							
	Million cubic feet per day				Million tonnes per year			
	Min		Max		Min		Max	
Economic life	*20yr*	*25yr*	*20yr*	*25yr*	*20yr*	*25yr*	*20yr*	*25yr*
Hastings (3)	102	81	347	278	1.90	1.56	6.66	5.33
Conroe (3)	75	60	208	167	1.40	1.15	4.00	3.20
Tom O' Connor (7)	63	50	210	168	1.21	0.97	4.00	3.22
Webster	59	48	205	164	1.14	0.91	4.00	3.15
Seeligson (25)	30	26	53	34	0.60	0.29	1.42	0.82
West Ranch (8)	26	23	49	39	0.50	0.15	0.93	0.74
Hull (3)	26	23	47	38	0.50	0.27	0.90	0.72
Giddings (2)	23	19	71	46	0.45	0.36	1.37	1.10
Borregos (10)	15	13	78	62	0.30	0.17	1.50	1.20
Oyster Bayou	14	11	74	59	0.27	0.21	1.42	1.13
Goose Creek	14	11	36	28	0.27	0.38	0.68	0.55
Old Ocean (3)	12	10	37	30	0.20	0.10	0.72	0.57
Tomball (9)	12	10	22	22	0.2	0.14	0.42	0.34
Gillocks (4)	12	10	19	15	0.24	0.18	0.37	0.29
Pearsall#	11	9	29	23	0.21	0.26	0.55	0.44
Liberty, South	10	8	29	23	0.18	0.14	0.72	0.44
White Point (2)	10	8	32	25	0.24	0.11	0.60	0.48
Pierce Junction	9	7	24	20	0.18	0.14	0.47	0.37
Willamar (4)	8	6	21	19	0.11	0.09	0.40	0.32
Orange (2)	7	5	19	15	0.13	0.11	0.37	0.27

Table 6 *continued*

MAIN OIL FIELDS AND CATCHMENTS (number of minor fields in brackets)	CO_2 REQUIREMENTS FOR ENHANCED OIL RECOVERY AND GEOLOGIC SEQUESTRATION							
	Million cubic feet per day				Million tonnes per year			
	Min		Max		Min		Max	
Economic life	*20yr*	*25yr*	*20yr*	*25yr*	*20yr*	*25yr*	*20yr*	*25yr*
Stowell (5)	7	5	20	16	0.12	0.09	0.39	0.31
Portilla (4)	7	5	20	16	0.10	0.08	0.39	0.31
Big Wells (3)	6	7	30	30	0.18	0.10	0.58	0.46
Fig Ridge (2)	6	5	18	14	0.11	0.09	0.35	0.28
Refugio-Fox (6)	6	5	14	11	0.10	0.08	0.27	0.21
T-C-B	5	4	14	11	0.09	0.07	0.27	0.21
Total	**575**	**459**	**1,726**	**1,373**	**10.91**	**8.20**	**33.75**	**26.46**

 # Pearsall is outside but close (about 20 km) to the nearest Texas Gulf Coast official border.

Minimum requirement is for EOR only. Maximum requirement includes sequestration.

Selecting the CO_2 sources

Total CO_2 emission from power plant is the most significant in Texas as it accounts for 84% of the state's CO_2 emissions.

There are over 40 large power plants (≥300 MW) in the Texas Gulf Coast alone compared to about 28 refineries and fewer high yielding industrial sources in the whole of Texas. Besides, whilst power plants produce their emissions from a single point source, some emitters like refineries have multiple exhaust stacks, which present an additional technical challenge in terms of integrating the exhaust-gas gathering system (Simmonds, Horst, Wilkinson, Watt, & Roberts, 2003).

There were 202 fossil-fuel power plants with total capacity of 72,449 MW as of 2006 (BEG, 2006b). For the purposes of this thesis, it was shortlisted to 63 power plants by setting one (1) million tonnes CO_2 emission per annum as minimum threshold for a plant. The motivation for using one million tonnes CO_2 emissions as minimum benchmark was based on the fact that each of the existing commercial or full-sized CO_2 geologic injection sites, namely; Sleipner (in Norway), Weyburn (in Canada), In Salah (in Algeria) and Salt Creek (in USA) have been injecting on the average a million tonnes per year (IPCC, 2005).

The 63 power plants comprised 45 natural gas and 17 coal-fired plants (*list does not include future plants*) with total installed capacity of 60,131 MW as of 2006 (Table 7). There were other carbon-based fuel plants, namely landfill gas, distillate oil, but their installed capacities were not large enough (<50 MW per plant) to make the list.

Table 7. Shares of coal and gas thermal power plants in Texas (BEG, 2006).

Thermal Plant	Number installed	Installed Capacity MW	Average Capacity factor	Annual Generation GWh	Estimated CO_2 emissions Million tonnes Annual	Daily
Gas fired	45	40,555	70%	260,294	211	1.1
Coal fired	17	19,576	80%	139,697	141	0.5
Total	**63**	**60,131**		**399,991**	**352**	**1.5**

Meeting the CO_2 supply requirements

EOR requires continuous delivery of CO_2, else it would not work. Important factors for CO_2 supply include the purity, period of availability, reliability, characteristics of supply, transportation mechanisms and expected production costs.

Average capacity factor of the coal plants was 80% in 2005 meaning, the coal plants usually run as base-load. Moreover, for a given megawatt-hour of power generated, natural-gas-fired plants emit between 50-60% of the CO_2 effluent that a comparable coal-fired plant does. These make coal plants the obvious choice for CO_2 supply.

However, future CO_2 emission regulations could force some of the coal plants to lose their base-load privileges, if not capture-ready or fitted with capture. For this reason, natural gas fired plants have also been included, even though, they had operated at relatively low capacity factors in the past.

In Texas as in most parts of the United States, higher than expected natural gas prices between 2005-2008 resulted in lower capacity utilization factors for natural gas plants originally built for base- load operation. The low operational capacity factors were due to relatively high cost of the fuel*;{natural gas $6-10/mmBTU compared to coal at $1-2/mmBTU }* between 2005-2008. Most plants were built when natural gas fuel price ≤ $2/mmBTU. For natural gas plants, fuel costs account for about 70% of operational expenses. As generation cost became too costly to dispatch therefore, the plants were run much less often, sometimes as low as 10% from 2005-2008.

Selected power plants in Texas Gulf Coast

Just as with Texas, total CO_2 emission from power plants is the most significant CO_2 source in Texas Gulf Coast, it averaged 90 million tonnes per annum between 2005 and 2007, comprising about 38 million tonnes from total gas-fired plants (20,193 MW) and 52 million tonnes from total coal-fired plants (6,571 MW). Total coal plant installed capacity increases to 8,261 MW (inclusive of the LCRA 1,690 MW plant) with total CO_2 emissions as 64 million tonnes per annum.

Fourteen power plants comprising seven coal plants and seven gas-fired plants were finally selected after superimposing the GIS maps of the shortlisted 63 power plants and that of the 26 major oil fields to match the power plants to the nearest oil fields (Table 8 and Figure 16). The selected plants form 55.7% of installed power capacity in the Texas Gulf Coast.

The total gas-fired plants could emit as much as 130 million tonnes of carbon dioxide but due to relatively high natural gas price, most of the plants were compelled to operate at 37% capacity factor on the average per year between 2005 and 2007.

Table 8 is the selected thermal power plants for the carbon dioxide capture comprising seven gas-fired and seven coal-fired plants. The coal-fired plant owned by the Lower Colorado River Authority (LCRA) and located in Fayette country is included in the selection not only owing to its closeness to a selected EOR-candidate field but also the company has expressed the interest to participate in the project.

Table 8. Shortlisted Power Plants for the CO_2 Capture in the Texas Gulf Coast

	Plant Owner (*as of 2008*)	County	Fuel Type	Capacity MWe
1	AES NUGs	Harris	Coal	184
2	San Miguel Electric Coop Inc	Atascosa	Coal	410
3	San Antonio Public City Service	Bexar	Coal	546
4	Coleto Creek WLE	Goliad	Coal	570
5	San Antonio Public City Service	Bexar	Coal	892
6	Lower Colorado River Authority#	Fayette	Coal	1,690
7	Reliant Energy HL&P	Fort Bend	Coal	3,969
8	Central Power & Light Co	Victoria	Gas	461
9	"Entergy" Corporation	Montgomery	Gas	543
10	Barney M Davis	Nueces	Gas	647
11	Formosa Plastics Corp	Calhoun	Gas	652
12	NRG Energy	Harris	Gas	878
13	Reliant Energy HL&P	Harris	Gas	1,422
14	"Entergy" Corporation	Orange	Gas	2,051
			Total	**14, 915**

 # Fayette county is not but neighbours the Texas Gulf Coast region. The Lower Colorado River Authority (LCRA) coal plant is selected owing to its closeness to one of the selected EOR-candidate fields.

"Entergy" is a registered tradename and not to be confused with "Energy".

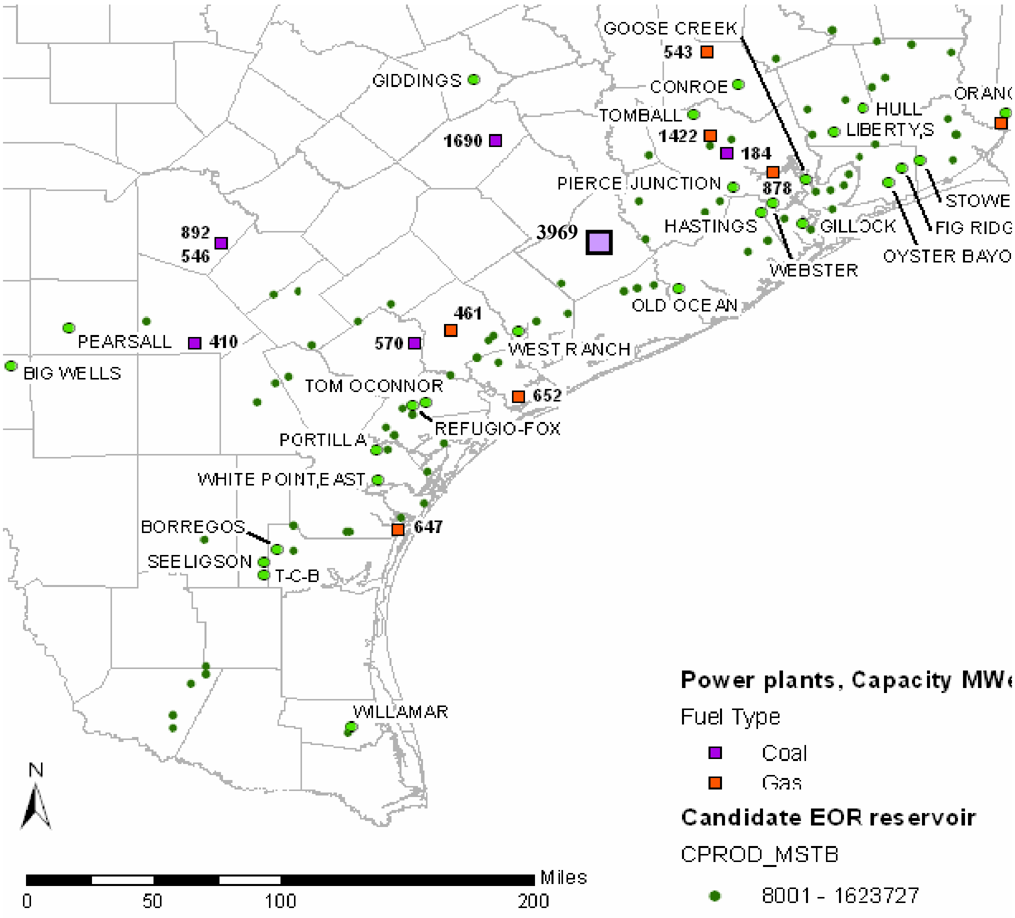

Figure 16. Location of the selected power plants for CO_2 capture and the EOR- candidate oil fields in Texas Gulf Coast (BEG, 2006a)

Designing the Pipeline Network

Earlier work identified pipeline transport as the most practical method to move large volumes of CO_2 on land. The proposed pipeline network is therefore onshore (Svensson & Odenberger, 2004; IPCC, 2005).

Selecting the Right of Way

Some of the oil fields and power plants are either located in or close to restricted zones like national parks, water bodies, urban areas, recreational parks etc (Figure 17).

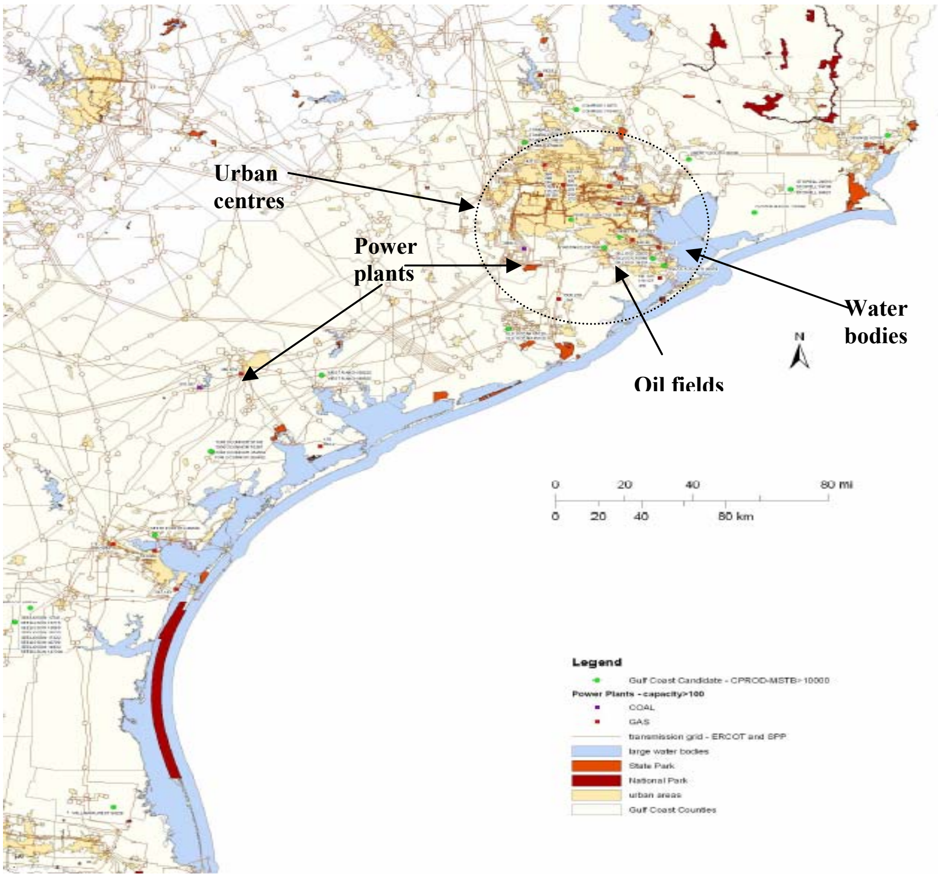

Figure 17. Locations of oil fields and power plants in relation to sensitive areas in Texas Gulf Coast 9*(Adapted from BEG, 2006)*

However, large gas pipeline such as envisaged in this thesis may not be permitted to go through a highly urbanised area, a wetland, national parks, waterway or other environmentally sensitive areas due to NIMBY (not-in-my-backyard) syndrome and other perceived environmental and accident risks by the public. Right-of-Way (ROW) cost could increase by 10-15 times if it is ever going to be permitted (Heddle, Herzog, & Klett, 2003). There are however existing natural gas and utility underground lines or ROW in the Texas Gulf Coast that could be used since such would attract less or no resistance from the public. There may be also no significant cost increment if pipeline rather runs parallel to waterways, railroads, or highways and if possible, avoiding large population centres, national and state parks. Pipeline passing through high elevation terrains would increase cost significantly due to the need for constructing pumping stations.

Selecting the most favourable ROW taking into consideration public and environmental sensitiveness as well as potential cost impact on pathway was accomplished with the super-imposing GIS maps of such areas against those of the power plants and the oil fields.

CO_2 flow requirements

Recalling that this thesis is considering retrofitting of existing power plants only *(refer to Chapter 1, Scope and Limitation*), there is 15-20% reduction in CO_2 emissions after selected existing plants have been retrofitted for CO_2 capture due to electrical conversion efficiency improvements. The 14 selected power plants would emit about 87.5 million tonnes of CO_2 per annum at business-as-usual (BAU) operations which is about 67% of total Texas Gulf Coast power plant CO_2 emissions.

The 14 selected plants when retrofit however would emit about 75 million tonnes of CO_2 a year which is 15% emission reduction from Business-as-usual

(BAU) case. The selected fields would however need 8-11 million tonnes annually for EOR activities and 26-34 million tonnes when sequestration is added (*refer to Table 6*). **Table 9** is the shortlist of the 14 selected thermal power plants total installed capacity of 14.92 Gigawatt.

Table 9. Expected CO_2 emissions after the selected power plants are retrofitted for the CO_2 Capture in Texas Gulf Coast

Location/ County	Fuel Type	Capacity MWe	No Capture CO_2 Emissions Million tonnes per year BAU* Conventional	Retrofit for Capture
Victoria	Gas	461	1.6 (70% CF)	1.4
Montgomery	Gas	543	1.9 (70% CF)	1.6
Nueces	Gas	647	2.3 (70% CF)	1.9
Calhoun	Gas	652	2.3 (60% CF)	2.0
Harris	Gas	878	3.1 (68% CF)	2.6
Harris	Gas	1,422	5.0 (70% CF)	4.3
Orange	Gas	2,051	7.3 (71% CF)	6.2
Harris	Coal	184	1.3 (76% CF)	1.1
Atascosa	Coal	410	3.1 (85% CF)	2.6
Bexar	Coal	546	4.3 (88% CF)	3.6
Goliad	Coal	570	4.8 (93% CF)	4.0
Bexar	Coal	892	6.4 (80% CF)	5.4
Fayette	Coal	1,690	12.1 (90% CF)	11.4
Fort Bend	Coal	3,969	32.0 (90% CF)	26.8
	Total	**14,915**	**87.5**	**74.9**

** BAU is Business-as-usual; CF is capacity factor of power plant*

These would amount to capturing 10-14% of the selected power plant total CO_2 emissions every year if EOR only but 35-45% if complemented with sequestration.

Selecting the hydraulic parameters

Hydraulic parameters, namely line-pipe sizes, fluid properties and flow rates, heat transfer, compression ratios, etc are needed for the computation of the fluid flow equation (Equation 22) (Table 10).

Table 10. Design specifications for designing the CO_2 pipeline for Texas Gulf Coast.

Parameter	Characteristics
Pipe	Size (diameter), wall thickness, length, material made of the pipeline. Also, surface roughness and drag factor including the manufacturing or marketing grade (class) of the pipeline
Fluid	Density (min-1.80, max-1.98 kg/m^3); molecular weight (44 g/ml), viscosity (0.07); (IPCC, 2005).
Heat transfer	Inlet temperature of the gas; temperature of the soil or medium the pipeline is laid. Burial depth; soil or medium conductivity; heat transfer coefficient between the material of pipe and the soil (or medium). Transportation condition: Liquid/dense, supercritical phase Gas temperature: minimum 90 deg F (32 deg Celsius) critical temp for supercritical phase 88.5 deg F (31.4 deg Celsius) Ambient temperature: average range deg Celsius (deg Fahrenheit) Winter -4-+10 (25-50); Spring 20-27 (68-80) Summer 30-40 (86-104), Fall 21-33 (70-91)

Table 10 ***continued***

Parameter	Characteristics
Compressor	Unit or type of compressor intended to use, either natural gas, oil or electrical powered; fuel type; gas, oil or electricity. Compression ratio; and nameplate efficiency of the compressor. Also; ambient temperature; heat rate. compressibility ratio (min-85%, optimum max-95%)
System	Supply and demand forecast of the carbon dioxide; sources of the carbon dioxide and delivery locations for the EOR and/ or sequestration; maximum and minimum operating pressures; and elevation changes along the pipeline path.

Gas Quality	**Purity**	Min 95%; Max 99%
	Water content	0.489 m^3 in vapour phase. Should contain no free water ($N+S+H_2S+HC+O+H_2O \leq 5\%$)
	Hydrogen sulphide content	1500 parts per million by weight of H2S ($N+S+H_2S+HC+O+H_2O \leq 5\%$)
	Total Sulphur	1450 parts per million by weight of sulphur ($N+S+H_2S+HC+O+H_2O \leq 5\%$)
	Nitrogen	Not more than 4% of total volume ($N+S+H_2S+HC+O+H_2O \leq 5\%$)
	Hydrocarbon	Not more than 5% of total volume ($N+S+H_2S+HC+O+H_2O \leq 5\%$)
	Oxygen	10 parts per million by weight of oxygen ($N+S+H_2S+HC+O+H_2O \leq 5\%$)
	Temperature	Delivery temperature not to exceed 120 deg F (48.9 deg Celsius)
	Delivery pressure	Min 9 MPa , Max 15MPa

There are now standard procedures for the design considering the experience with the West Texas pipelines. The experience from the West Texas pipelines would also be utilized for protection against corrosion, trenching and backfilling, installing fracture arresters, etc.

Fluid temperature ***T*** (assumed to be the same as the surroundings), density ***ρ*** and viscosity ***υ*** are the three main properties that affect fluid transport in pipelines. Density ***ρ*** and viscosity are defined as ***f(p,T)*** since viscosity is also critically important in estimating pressure drop.

For maximum throughput, the CO_2 would be in a liquid or supercritical/dense state. (Odenberger & Svensson, 2003).

Supercritical/dense flow ensures one phase flow which is relatively easier to handle compared to multiphase flow. For instance, allowing CO_2 to go into two-phase flow can cause cavitation problems, particularly in the booster stations. Transporting a high density fluid thus facilitates efficient transportation.

Operating temperatures of CO_2 pipelines are generally dictated by the temperature of the surrounding soil which is also determined by the ambient temperatures (Table 10). Soil temperature would also depend upon the thermal conductivity of the soil.

In order to reduce difficulties in operation, it is desirable that a CO_2 pipeline operates at pressures greater than 8.6 MPa where the sharp changes in compressibility of CO_2 can be avoided across a range of temperatures likely to be encountered in the pipeline system (Farris, 1983). Compressibility of CO_2 is however highly sensitive to impurities, such as hydrogen sulphide (H_2S) or methane (CH_4); in fact there is a significant difference between the compressibility of pure CO_2 and CO_2 with 10% H_2S (by volume) (McCoy, 2008). Impurities in the CO_2 also affect the efficiency of the EOR rate due to the less efficient CO_2 – oil miscibility. There is thus the need to ensure the high purity requirements as indicated in **Table 10**.

Estimating the compression and pump power requirements

After capturing the gaseous CO_2 from the flue gas, it is compressed from initial atmospheric pressure (0.1 MPa) up to a liquid or dense state (pressure above 7.38 MPa) depending upon gas temperature (*refer to Figure 10*).

For the gas phase, a compressor is required for the compression, but a pump could be used to boost the pressure whilst in the liquid/dense phase.

Assuming that the critical pressure, 7.38 MPa is the "cut-off" pressure, then a compressor is used from 0.1 to 7.38 MPa, and then a pump takes over for pressures above 7.38 MPa to high supercritical pressures, say 15 MPa to ensure and maintain supercritical flow for longer distances and wider range of temperatures in the pipeline system (Figure 18).

$P_{initial}$ = 0.1 MPa $P_{cut\text{-}off}$ = 7.38 MPa P_{final} = 15 MPa

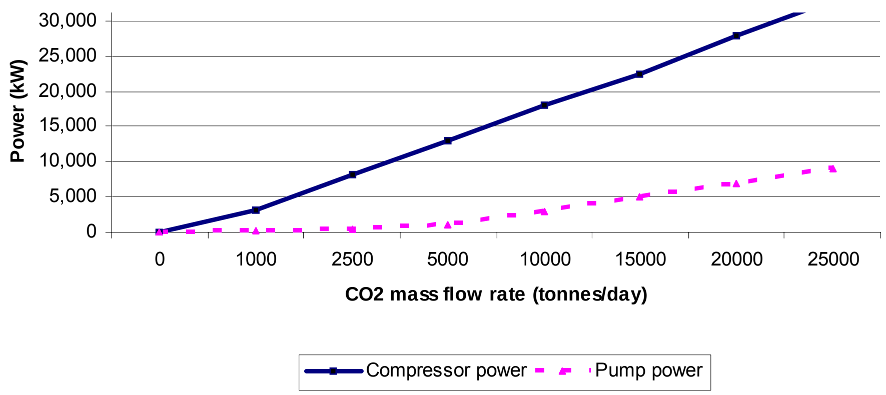

Figure 18. Power Requirement of Compressors and Pumps as a function of CO_2 Mass Flow Rate

Figure 18 *was obtained by assuming* ρ *= 630 kg/m*^{3}*,* η_p *= 0.75, 1000 = Number of kilogrammes per tonne, 24 = Number of hours per day, 10 = Number of pressure per MPa, 36 = Number of m*^{3} *x bar/hr per kW; data adapted from McCollum & Ogden (2006).*

Figure 18 indicates that more power is required for compression than for boosting the CO_2 pressure from the critical pressure to higher pressures (*recalling Equation 31*).

This is partly because the compressor raises the CO_2 pressure from 0.1 to 7.38 MPa, a total compression ratio of 73.8, whereas the pump raises the pressure from 7.38 MPa to 15 MPa, a total compression ratio of only 2.0.

In any case more power being required for compression is not strictly due to the compression ratio, but it is also that the compressibility of a gas such as CO_2 decreases with increasing pressure (at constant temperature). For example, at the same suction temperature, it takes more energy to compress CO_2 from 0.1 to 0.35 MPa than it does to compress the same amount of CO_2 from 2 to 7 MPa, even though the compression ratio is constant.

CO_2 flow in the pipeline

The pipeline performance is governed by the Bernoulli's equation of state for real supercritical fluids (Equation 23).

For CO_2 being transmitted under supercritical condition, the changes in kinetic energy of the flowing CO_2 are negligible since there is no acceleration, and that the compressibility of the CO_2 or CO_2 containing mixture can be averaged over the length of the pipeline segment (Mohitpour, et al., 2003):

In addition, the typically long length of a CO_2 pipeline segment coupled with the lack of perfect insulation on buried pipelines means that it can be treated as an isothermal system, where the CO_2 is at the temperature of the earth surrounding the pipeline.

For supercritical flow with high flow rates, where the regime of flow is fully turbulent and the CO_2 is almost dry, the values of $\boldsymbol{K_i}$ and $\boldsymbol{K_d}$ in **Equation 29** are negligible compared to $\boldsymbol{K_s}$, therefore making the effective roughness of the pipeline as almost equal to the internal surface roughness of the pipe.

Estimating the internal diameter of the pipeline

Internal diameter of a line-pipe could be estimated from the graph in **Figure 13.**

Line-pipes are however not available in continuous diameters but are discrete. Thus the internal pipe diameter calculated must be adjusted to account for both available pipe diameters and the pipe wall thickness. A discrete size of line-pipe is frequently referred to by its Nominal Pipe Size (NPS), which corresponds approximately to the outside pipe diameter conventionally measured in inches.

McCoy (2008) has developed a chart such that by knowing the gas flow rate and the pipe length from the initial supply point to the point of delivery, the line-pipe size (diameter) can be selected from the chart (Figure 19).

Figure 19 shows McCoy's chart for discrete nominal pipelines sizes as a function of length at given flow rates in million tonnes per year.

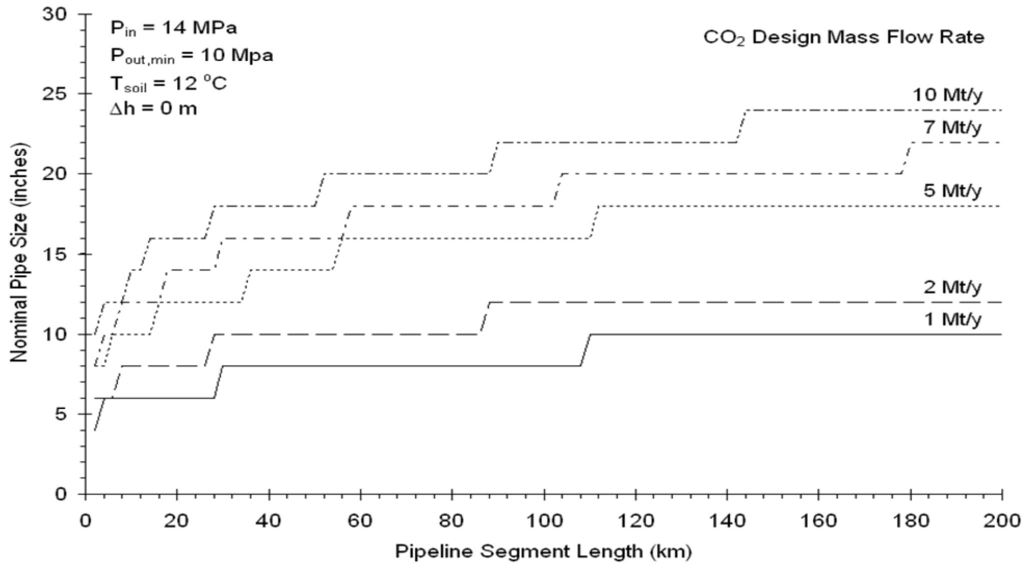

Figure 19. Nominal Pipeline sizes (diameters) as a function of length at given flow rates in million tonnes per year (Mt/y), *reproduced from McCoy (2008).*

The chart however is limited to inlet (input) and outlet (output) pumping pressure of 14 MPa and 10 MPa and assumed a uniform pipeline operating temperature of 12°C. The McCoy chart (Figure 19) also assumes an isothermal flow but in practice, there is a significant increase in temperature after compression which affects fluid behaviour and horsepower requirement.

The next step therefore is to estimate the compression and to find out the pressure drops per km for different pipeline sizes along the pipeline route so as to know where to install compressors or what initial compression pressures to use in order to maintain supercritical/dense flow of the CO_2 from the initial source to final destination.

Asante (1996) have elaborated potential impacts of other pipeline parameters including wall thickness, pipe grade, roughness, drag factor, burial depth and pressure buffers on pipeline networks and estimated their percentages. For instance, 10 ^{o}C-change in average operating temperature could cause 3% change in fluid flow; 1%-change in drag factor, leads to 1% change in flow rate. However, apart from change in inner diameter of a pipeline which could cause significant impact of 40-70% on the flow rate of the fluid, other pipeline parameters, besides operating pressure and temperature would not cause more than 1% change in fluid flow.

Pressure drop along the pipeline

This seemingly limitations of the McCoy's (2008) chart however could be eliminated by adjusting upwards the pipeline diameters to cover the extra expansion and also taking into account the common line-pipe sizes. The adjustment in most cases is accomplished by selecting the next higher diameter. In any case, this thesis has developed another chart (Figure 20) to complement McCoy's chart which is elaborated below.

To complement or improve upon McCoy (2008) chart (Figure 19), results from works of Farris (1983), Skovholt (1993), Asante (1996) and Odenberger & Svensson (2003) using different sizes of pipelines were combined on one graph and extrapolated to obtain a chart where pressure drop per km for different pipeline diameters are read at a glance (Figure 20). Typical values from the said authors produced a relationship, which could be represented by the formula:

$$y = 571.5x^{-1.0076} \quad \textbf{(35)}$$

*Where **y** is the pressure drop in **MPa** and **x** is the pipe diameter in inches.*

For instance, for a CO_2 flow of 0.7 tonnes per year through a pipeline route from Seeligson to TCB oil fields (Table 11) which is a distance of about 5 km, McCoy's chart (Figure 19) prescribes the use of 4-inch line-pipe. From Figure 20, there would be a pressure drop of about 27 MPa along the pipeline (estimated from a pressure drop of 14 MPa per 100km of pipeline). So, initial pumping pressure should be as high as 22 MPa to maintain supercritical condition. However, this would come with cost penalty. The alternative is to adjust upwards by selecting say 6- or 10-inch line-pipe which would drop the initial pumping pressure requirements to 17 MPa or 14 MPa.

From the chart (Figure 20), one can estimate the pressure drops for other pipeline sizes, immaterial of the elevation of the pipeline segment. It implies that for a selected line-pipe, when the pressure approaches the critical pressure of CO_2 (7.38 MPa) a booster station is required to maintain single-phase flow. For instance, for a 121-km, '10-inch' pipeline, initial pressure of 7.38 MPa would drop by 6 MPa at 100 km and by 7.25 MPa at the 121-km point, which means the pressure would only be 0.14 at the final delivery. To maintain a supercritical phase therefore, the initial compression pressure should be at least 15 MPa so that final delivery pressure at 121 km would be 7.76 MPa which is still supercritical provided fluid temperature is above the critical temperature. Adjustment may be accomplished by selecting the next higher diameter which is 12-inch pipeline. From the chart (Figure 20), the pressure drop is reduced to 5 MPa per 100 km (compared to the 6 MPa per 100 km for the 10-inch pipeline). The total drop for the 12-inch, 121-km line-pipe is about 6 MPa. So, if an initial compression is 14 MPa, final delivery pressure would be 7.96 MPa thus ensuring supercritical condition.

Selecting the initial compression to ensure supercritical condition for the fluid is however a balancing act between availability of material (line-pipe) on the market that can cope with that high initial pressure and costs of the line-pipe and construction of the pumping stations. To ensure, supercritical flow conditions, line-pipes with ASME-ANSI Class 900# and 1500# ratings are envisaged. The former has a maximum allowable operating pressure of 15.3 MPa at 31.4°C. Higher pressures would require ASME-ANSI Class 1500# flanges (Mohitpour et al., 2003).

The resulting integrated pipeline network

Graphical-manual method

The procedure for designing the integrated pipeline is as follows.

- After using the GIS maps to chart out the Right-of-Way (ROW); and knowing the distances between the power plants (sources) and the targeted oil fields (sinks); and the required CO_2 requirements,
- From the distances and the CO_2 requirements, one may look up from the McCoy (2008) chart (Figure 27) for the corresponding line-pipe sizes iteratively. To find out the compression requirements and pressure drops along the selected line-pipe, look up from **Figure 20**.

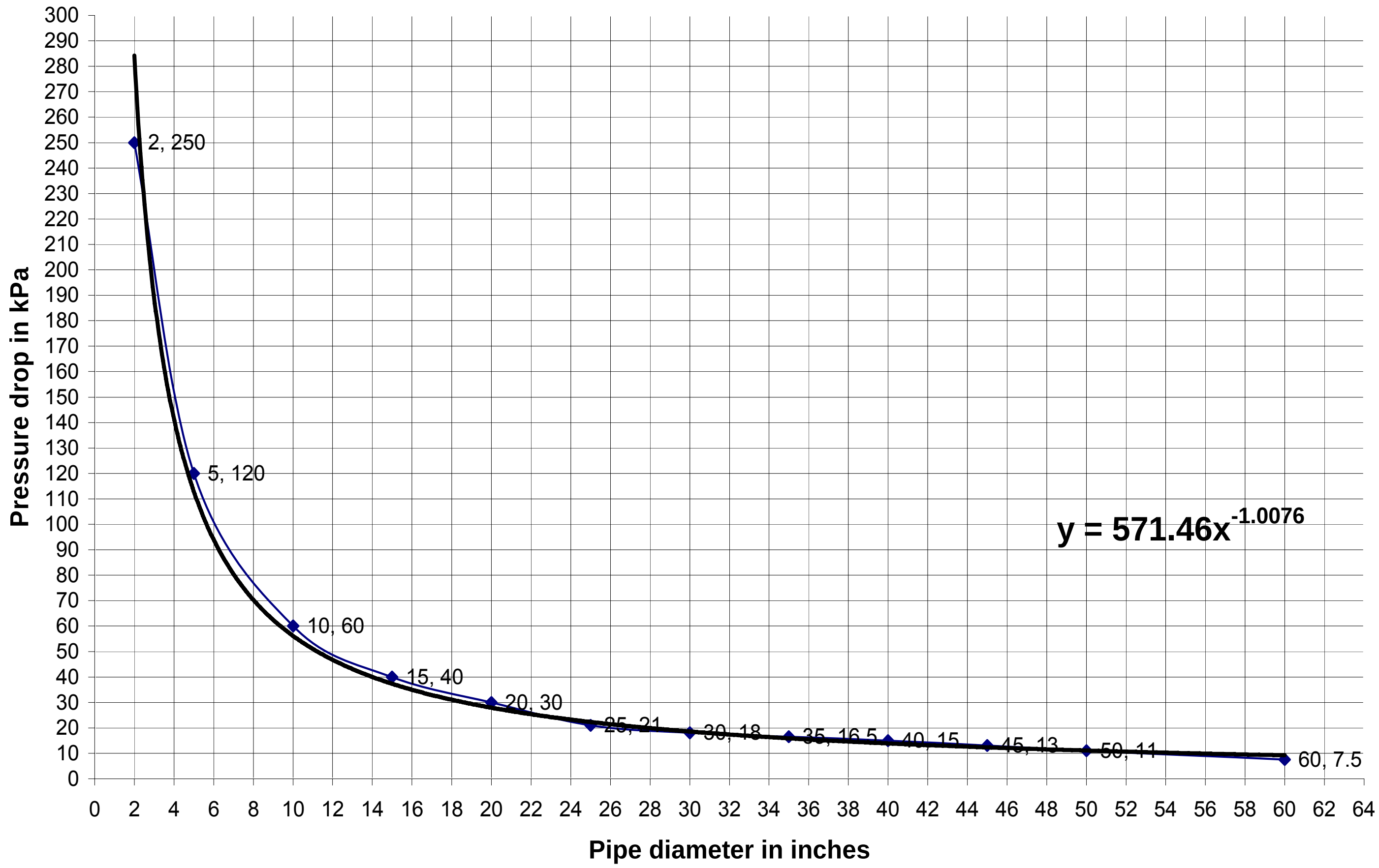

Figure 20. Pressure drop per kilometre of CO_2 pipeline for different pipeline diameters.

- For instance, a 14-inch pipeline would drop 40 kPa per every km (4 MPa per 100 km). To reduce the number of booster pumps, one may decide to go for higher diameter pipelines say 28 inch pipeline which drops just 20 kPa per km (2 MPa per 100 km).
- One may also choose to ignore the McCoy chart and go straight to **Figure 20** to select the pipeline of choice. Choice of pipeline size is going to depend largely on flow capacity and cost. The latter is discussed in Chapter 4.

Designer software method to draw the pipeline network

After using the GIS maps to chart out the Right-of-Way (R-O-W); knowing the distances between the power plants (sources) and the targeted oil fields (sinks); knowing the required CO_2 requirements (*refer to Table 6*), the data were fed into a designer software developed by Pipeline Design Solutions International and with their permission (Asante, 2008).

Figure 21 is the output of the designer software. The designer software also provides the pumping pressures and where the booster pumps are to be installed.

The manual procedure however yield about the same results as the designer commercial software and therefore provides quick and preliminary estimates for pipeline design.

The results of the two methods; the manual using the charts and the designer Pipeline Studio® software are compared. Both approaches ensure that the fluid maintains a dense phase.

The designer Pipeline Studio® software required weighted average pressure of 12.5 MPa, whilst the graphical-manual method prescribed a weighted average pressure of 11.3 MPa (Table 11). Average deviation between the two is 1.7.

The major difference however is that the designer Pipeline Studio® software method takes into account the practical and dynamic operations of the motors of the pumping stations in order to ensure their optimum smooth operations, since irregular humming or unharmonised operations of the pumping stations could affect their life spans.

The integrated pipeline network would cover about 1,600 km with pipeline diameters ranging from 8-40 inches (203-1,016 millimetres) (Figure 21).

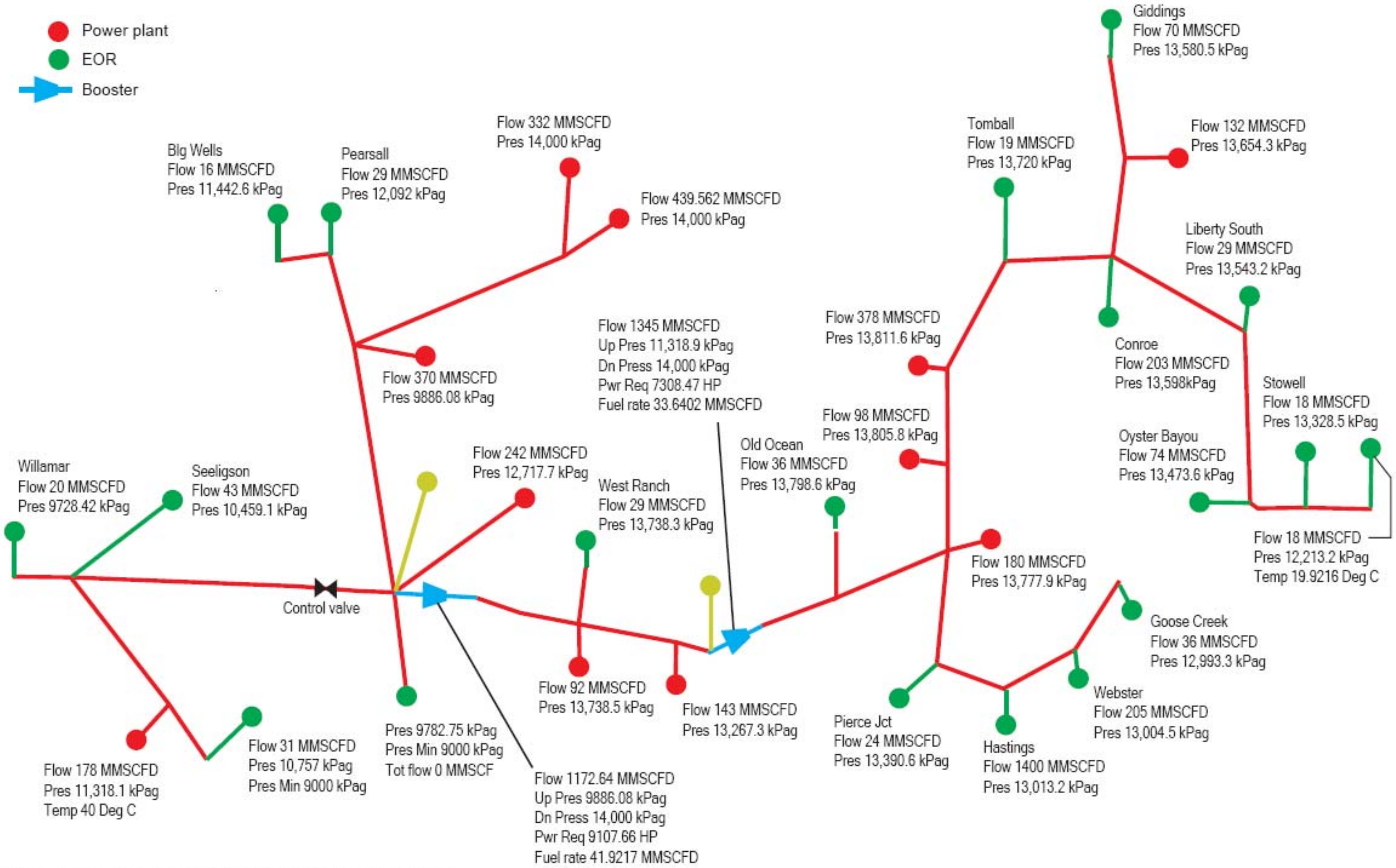

Figure 21. The Right-Of-Way for proposed CO_2 pipeline network with the required pressures and flow rates for Texas Gulf Coast

Table 11 The Texas Gulf Coast CO_2 Pipeline Routes and their pumping pressures

CO_2 Pipeline Route	Dist-ance	CO_2 Flow	Dia-Meter	Pipeline Solution Software	Chart/ Manual Method
	Km	Tonnes /year	Inches	Initial Pumping pressures (MPa)	
Willamar ⟵- T-C-B Fields	121	0.4	8	9.7	16
T-C-B ⟵ Seeligson Fields	5	0.7	8	10.5	9
Power Plt1 → White Point fields	34	0.6	8	10.7	10
Power Plt1 → Seeligson fields	82	3.4	16	11.3	10
Seeligson ⟵-Power Plt4	184	3.0	16	12.7	14
Power Plt4 → Tom Oconnor Fields	42	4.2	16	9.0	9
Tom Oconnor → Refugio Fox	5	0.3	8	9.0	9
Power Plt7 → Power Plt6→ Power Plt5	92	16.0	40	14.0	9
Power Plt5 → Power Plt4	126	19.0	40	9.8	9
Power Plt5 → Pearsall Fields	68	1.0	10	12.1	11
Pearsall → Big Wells Fields	42	0.6	10	11.4	10
Power Plt3 → West Ranch Fields	26	0.6	10	13.7	10
Power Plt4 → Power Plt3	26	24.0	36	12.7	10
Power Plt3 → Power Plt2	24	23.0	36	13.7	10
Power Plt2 → Power Plt11	185	26.0	52	13.8	10
Power Plt8 → Giddings Fields	126	1.4	12	13.6	14
Power Plt8 → Conroe Fields	35	1.1	10	13.6	10
Power Plt9 → Tomball Fields	19	3.2	16	13.7	10
Tomball → Conroe Fields	31	3.0	16	13.6	10
Conroe → Hull Fields	60	4.0	16	13.5	10
Hull → Liberty South fields	26	3.0	16	13.5	10
Liberty South → Oyster Bayou fields	43	2.5	16	13.5	10
Oyster Bayou → Fig-Ridge fields	13	1.0	16	12.2	10
Fig Ridge →Stowell → Orange fields	69	1.0	10	13.3	12
Power Plt9 ↔ Power Plt10	18	24.0	36	13.8	12

Table 11 *continued*

CO_2 Pipeline Route	Dist-ance	CO_2 Flow	Dia-Meter	Pipeline Solution Software	Chart/ Manual Method
	Km	Tonnes /year	Inches	Initial Pumping pressures (MPa)	
Power Plt10 ↔ Power Plt11	18	24.0	36	13.8	12
Power Plt11 → Pierce Junction Fields	19	0.5	8	13.8	12
Power Plt11 → Hastings Fields	19	12.0	16	13.0	12
Hastings → Webster fields	8	4.0	12	13.0	12
Webster → Goose Creek fields	19	0.8	8	12.9	12
Hastings → Gillock, South fields	31	0.4	8	13.0	10
Total	**1,613**		**Ave:22**	**Ave:12.45**	**Ave 11.30**

Ave is weighted Average

The graphical/manual method therefore is recommended for providing preliminary estimates where professional/designer softwares are not readily available.

Two booster stations would be required for the network (as shown in Figure 21). The locations of the booster stations accomplish two things; the suction control pressure ensures that the supercritical conditions are maintained while the discharge control pressure boosts the system pressure for further downstream transportation.

Sensitivity Analysis

The following three different scenarios illustrate the calculations and methodology applied in the pipeline selection. **Table 12** illustrates the procedure used to determine the minimum number of booster stations required for three pipelines with different diameters.

Table 12. Different operational conditions of the pipeline under economic life, distance and pressure used for the sensitivity analysis.

Common Data for all Scenarios			
	Economic life of project	Year	**20**
	Pipeline Distance	Km	**300**
	Initial pressure	MPa	**13**
Scenario 1			
	Pipeline diameter	Inch	**16**
	Free flow capacity	Mt/year	**3**
	Pressure drop per 100 km	MPa	**4**
Scenario 2			
	Pipeline diameter	Inch	**40**
	Free flow capacity	Mt/year	**35**
	Pressure drop per 100 km	MPa	**1.5**
Scenario 3			
	Pipeline diameter	Inch	**64**
	Free flow capacity	Mt/year	**110**
	Pressure drop per 100 km	MPa	**1**

Mt/year is million tonnes per year.

Initial pressure is assumed to be 13 MPa. 100 kPa change in operating pressure causes about 2% change in fluid flow (Asante, 1996). The iteration results are shown in **Figures 22-24**.

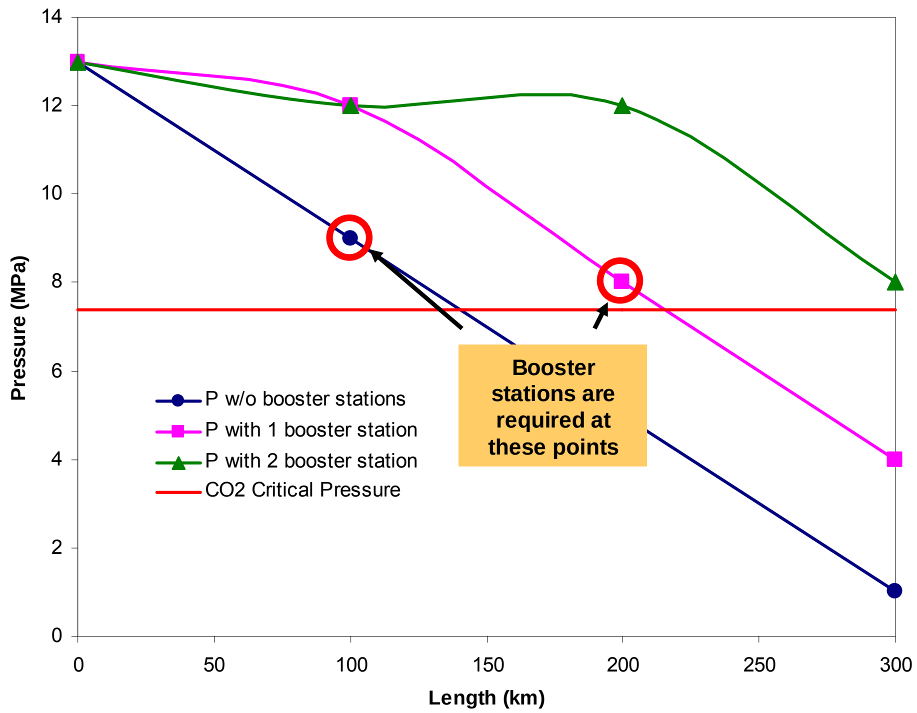

Figure 22. Pipeline pressure at different lengths for a 16-inch diameter line-pipe

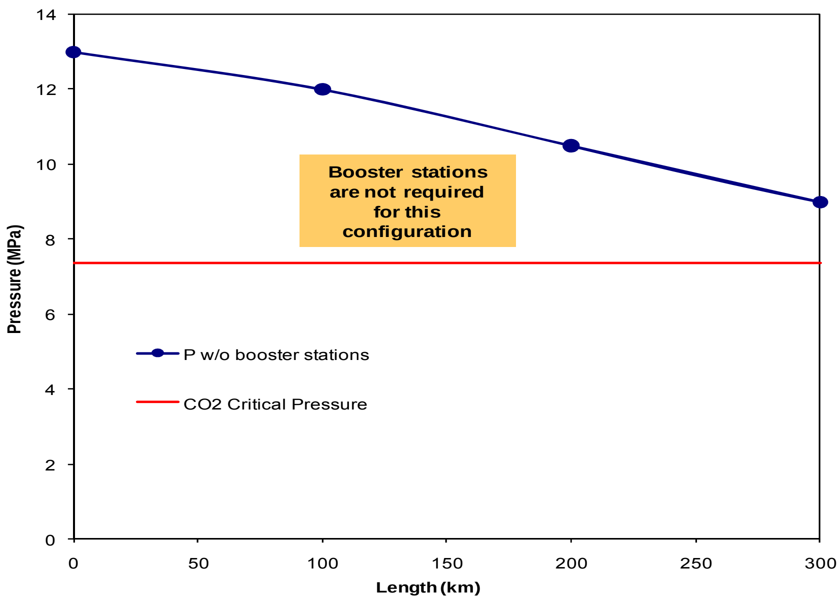

Figure 23. Pipeline pressure at different lengths for a 40-inch" diameter line-pipe

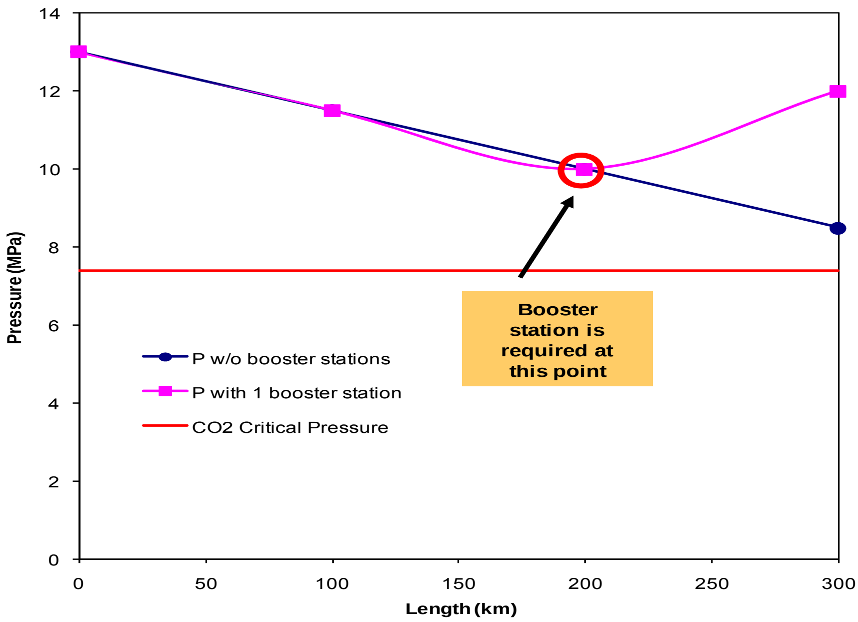

Figure 24. Pipeline pressure at different lengths for a 64-inch diameter line-pipe

The parameters affected in the sensitivity study are the diameter and the distance (length) of the pipeline.

From **Figures 22-24**, the bigger the diameter, the lower the pressure drops. Pressure in small diameter pipelines drops faster and therefore the need for booster stations. Keeping the pipeline pressure over the CO_2 critical pressure determines the number of pumping stations is to be installed.

Modelling the CO_2 Capture Plant

Existing power plants

Existing operative post combustion power plants imply that retrofit them for CO_2 capture should be the first option for economic evaluation before thinking of retiring the plants prematurely and be replaced by new plants. There would however be challenges which include:

- Site constraints such as availability of land for the capture equipment.
- Low energy efficiencies of some of the existing plants due to old age and, so boilers and electrical units would have to be upgraded.
- Some might have short economic life span and so would have to be rehabilitated first before the retrofit.

Energy requirements for CO_2 capture

The energy usage of the absorption process is the sum of the thermal energy to regenerate the solvents and the electrical energy required to operate pumps and the flue gas blowers or fans *(refer to Figure 14)*.

The heat required for heating up the solvent to release the absorbed CO_2 (regeneration process) would be extracted from the steam cycle in the power plant. For coal-fired plants, low pressure steam would be extracted prior to the last expansion stage of the steam turbine. For a natural gas fired power plant, the low-pressure steam would be extracted from the last stage in the heat recovery steam system. This would avoid interfering significantly with the power conversion efficiencies of the plants whilst obtaining the right amount of heat required to regenerating the solvents.

Heat requirements used for the Texas Gulf Coast are typical values available in literature; they are between 2.7 – 3.3 GJ/tCO_2 (2.6-3.1 mmBTU/tCO_2) (IPCC, 2005).

Energy is also required to compress the CO_2 recovered from the solvent, to the initial supercritical state pressure required for transport and delivery of the CO_2 to the EOR site. Values used for Texas Gulf Coast are also typical values derived from literature (IPCC, 2005):

- For coal power plant: 0.06 – 0.11 GJ/tCO_2 (16.7 – 30.6 kWh/tCO_2)
- For natural gas power plants: 0.22 – 0.33 GJ/tCO_2 (61-91.7 kWh/tCO_2).
- Compression of the CO_2 to 11 MPa requires about 0.4 GJ/tCO_2 (111 kWh/tCO_2).

CHAPTER FOUR

ECONOMIC MODELLING OF THE CARBON DIOXIDE CAPTURE AND TRANSPORTATION

In this chapter, costs of the pipeline network and CO_2 capture technology are estimated. To estimate the pipeline cost, literature of existing cost models are reviewed. Potential job creation from constructing the capture plants, pipeline network and the EOR field development is also estimated.

Cost of the pipeline network

Total installed cost of a pipeline is made up of the following four key cost categories:

i. Material cost covering line-pipe, transportation, pipe coatings, cathodic protection.
ii. Labour including cost of construction, laying and pipeline supervisory works.
iii. Right-of-Way (ROW) covering cost of obtaining ROW and compensations for damages and claims during construction.
iv. Miscellaneous expenses including costs of surveying and environmental impact assessment.

Between 2005-2008, the global industry witnessed major cost escalations; labour cost (in the United States) doubled, prices of steel rose from about $650 per tonne to $1,300 per tonne and cost of capital and other miscellaneous costs also increased (US DOE, 2005). The period saw soaring commodity metal prices

(Figure 25a). The pipeline construction industry was not spared as shown in **Figure 25b**, the high oil prices encouraged the industry to invest in infrastructure projects and that could contribute to the high correlation between oil prices and consumption of steel during the period.

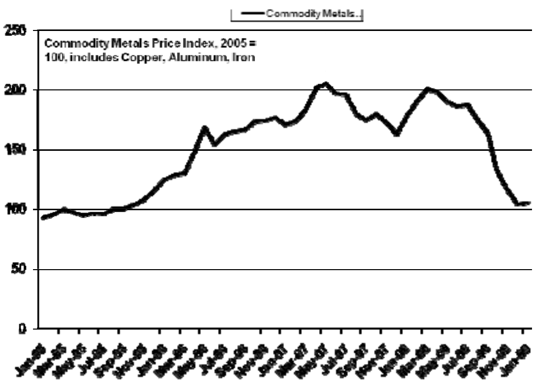

Figure 25a. Trend of Commodity metal prices from January 2005-January 2009. ***Courtesy of HESS Corporation 2009***

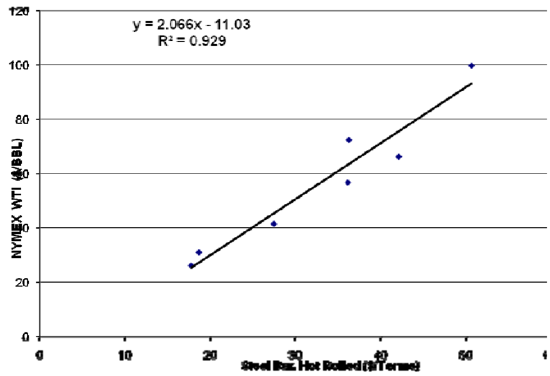

Figure 25b. Regression between West Texas oil index and steel. ***Courtesy of Hess Corporation, 2009***

{Although costs returned almost back to January-2005-levels in late 2008, according to Figure 4.1a, they would likely rise again once the world economy has started to recover}

In 2006, Denbury Resources Inc, a pipeline developer in the United States announced a projected cost of \$225-250 million to build a CO_2 pipeline of 24-inch diameter and 448-523 km in length from Donaldsonville in Louisiana to the Hasting Field in Texas, USA. The cost of this pipeline project was revised to \$700-750 million in 2007, despite maintaining the same pipeline sizes, right-of-way and productivity factors (Denbury, 2007; US DOE, 2006; World Bank, 2008).

Impact of cost on pipeline Right-of-Way

Pipeline passing through high elevation terrains would increase the cost significantly due to the need for constructing pumping stations. According to the IEA GHG (2002), terrain factor (F_T) for diverse land conditions are as follows: cultivated land=1.10, grassland=1.00, wooded=1.05, jungle=1.10, less than 20% mountainous=1.30, more than 50% mountainous=1.50. **Figure 26** shows how costs increase when the pipeline route passes across different areas.

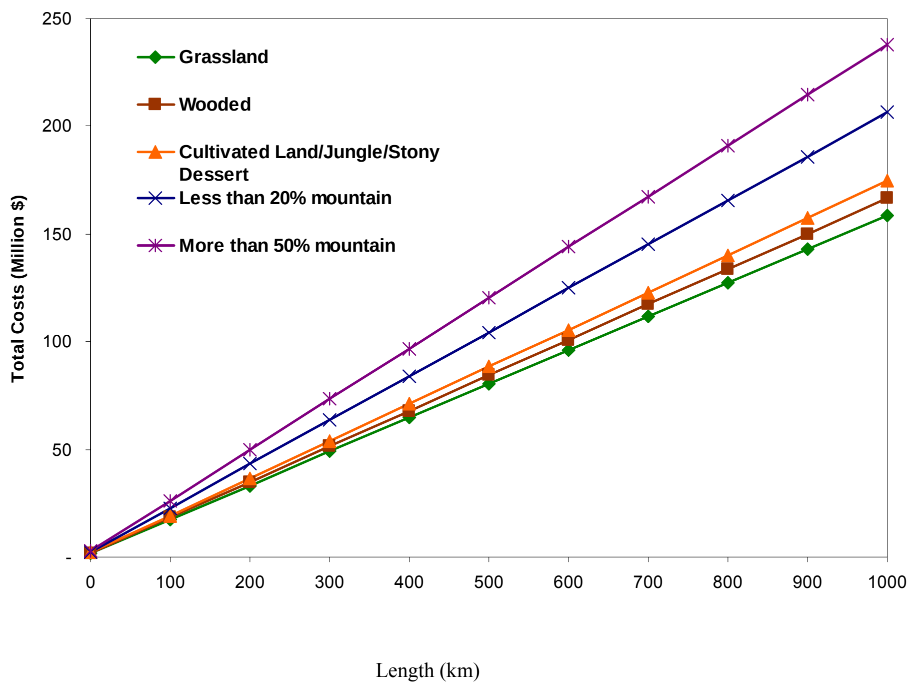

Figure 26. Pipeline costs for different land terrain (*IEA GHG, 2002*)

The most dramatic cost elevation occurs when the pipeline is built in mountainous lands owing to high construction costs due to high lifting cranes besides additional pumping station requirements. 100-metre change in elevation leads to about 1.5% change in fluid flow (Asante, 1996).

Review of pipeline cost models

When existing cost models were used to compute the cost of the proposed pipeline, the cost per inch per km were nowhere near cost submissions by the industry to US FERC (2009). The various models are able to predict pipeline capital cost of the past to some extent but under-estimated costs announced by the industry between 2006-2008 for pipeline with unchanged productivity factors/indices and even when the all modelled costs are standardized to the same currency year (Page, 2000).

Only Ogden model (2004) provided estimates that fell within the 2006-2008 higher cost quotations. IEA GHG2005/3 (IEA, 2005) and Ecofys model (2003) came close.

There were also large variations among forecasted costs by the different models.

In order to account for cost escalation in pipeline model therefore, the following existing pipeline cost models were reviewed. They are the: McCoy model (2008); MIT model (Heddle, Herzog, & Klett, 2003); Ogden model (2004); Ecofys model (2003); IEA models (2002); (2005); Parker model (2004); and McCollum & Ogden model (2006).

McCoy model

McCoy (2008) assumed many similarities between natural gas and CO_2 transport and that both are transported at similar pressures, approximately 10 MPa and greater. For these reasons he used data set based on natural gas pipelines to develop pipeline capital cost model by doing regression analysis of natural gas pipeline project costs from 1995-2005.

McCoy's entire set of cost equations applying to the Southwest Region of the US, which includes Texas, is as follows:

Materials $\mathbf{Log\ (C_{mat}) = 4.7181 + 0.0287 * \log(d) + 0.917 * \log(l)}$ **(36)**

Labour $\mathbf{Log\ (C_{labour}) = 5.5024 + 0.0172 * \log(d) - 0.219 + 0.7890 * \log(l)}$ **(37)**

Misc. $\mathbf{Log\ (C_{misc.}) = 5.2552 + 0.0147 * \log(d) + 0.789 * \log(l)}$ **(38)**

ROW $\mathbf{Log\ (C_{mat}) = 4.4243 + 0.009 * \log(d) + 1.0504 * \log(l)}$ **(39)**

Where d is diameter in inches and l is the length of the pipeline in kilometres. Cost unit in US dollars

The MIT model

Just as McCoy did, the MIT group used historical cost data for natural gas pipeline construction to derive the CO_2 pipeline costs. From this data set, they concluded that on average, construction cost for CO_2 pipelines would be **$20,989/in/km** independent of the pipeline diameter (Heddle et al., 2003).

The MIT model further indicates that O&M costs would be $**3,100/km/year**, independent of pipeline diameter and would be about 2% of the initial capital cost of the pipeline construction on average.

Total Annual Cost ($/yr) = {($20,989/in/km) * D * L * CRF} +{($3,100/km/yr) * L} (40)

Where D = pipeline diameter [in], L = pipeline length [km], and CRF = Capital Recovery Factor; CRF is used to annualised the total cost.

Thus, the total annual cost equation is as follows:

The MIT model assumes pipeline roughness, or friction factor, to be 0.00015 (1.5×10^{-4}).

The Ogden model

The Ogden CO_2 transport model was originally developed to estimate the cost of hydrogen pipeline distribution infrastructure (US DOE/NETL, 2004). Ogden adapted an equation from Farris (1983) to calculate the volumetric flow rate of CO_2 and used capital costs per mass flow based on four different pipeline size diameters (16, 30, 40 and 64 inches) from Skovholt (2003) to estimate the total pipeline costs.

Total Capital Cost (\$) = Capital Cost (\$/km) / m x L (km) **(41)**

Where m = mass flow rate [tonnes/day], and L = pipeline length [kilometres]

Ogden's capital cost equation is thus a direct function of CO_2 flow rate and pipeline length. The Ogden model estimates the O&M factor to be 4% of total capital cost calculates the friction factor to be about 0.0021 (2.1×10^{-3}).

The Ecofys model

The Ecofys model for CO_2 pipeline transport cost was a report submitted to the European Commission on the potential of CCS for meeting Kyoto Protocol targets for emission reduction in the European Union (Ecofys, 2003). The total pipeline capital cost in euro is given by:

$$\textbf{Total Capital Cost (€)} = (€1100/m^2) * F_T * D * L \qquad \textbf{(42)}$$

Where FT = correction factor for terrain = 1 for most common terrain, D = pipeline diameter [m], L = pipeline length [km]

The pipeline friction factor is less than 1.5 x 10^{-2} for perfectly smooth pipeline walls and about 2 x 10^{-2} for new and untreated steel.

The annual O&M costs are calculated as 2.1% of the total capital cost and the total annual cost is found by summing the annual capital and O&M costs:

Annual O&M Costs (€/yr) = (O&M factor) * Total Capital Cost **(43)**

Where O&M factor = 2.1%

The IEA GHG models

The IEA GHG models are three, namely;

- IEA GHG PH/6 model published in 2002.
- IEA GHG 2005/2 model published in 2005 and dedicated to Europe.
- IEA GHG 2005/3 model published in 2005 and dedicated to North America.

{IEA has no similar work for Africa yet}

IEA GHG PH/6 model is a spreadsheet-based computer model for estimating the costs and performance of CO_2 pipeline transport. For onshore pipeline cost computation, three equations were developed for three different ANSI piping classes, namely;

- ANSI #600, {Pressure ≤9 MPa (90 bar)},
- ANSI # 900, {Pressure ≤14 MPa (140 bar)}
- ANSI # 1500, {Pressure ≤ 22.5 MPa (225 bar)}.

Location factors (FL) for USA/Canada=1.0, Europe=1.0, UK=1.2, Japan=1.0, Australia=1.0.

Terrain factors (FT) are as follows:

Cultivated land=1.10, grassland=1.00, wooded=1.05, jungle=1.10, stony desert=1.10, <20%, mountainous=1.30, >50% mountainous=1.50.

For CO_2 pipeline transport the higher pressures involved demand using ANSI#900 and ANSI#1500. The equations developed for their pipeline capital costs are:

ANSI#900 $$\text{Cost (\$)} = F_L * F_T * 10^6 * [\,(0.0619 * L + 1.8529) + (0.00115 * L - 0.00001) * D + (0.000299 * L + 0.000003) * D^2\,] \quad (44)$$

ANSI#1500 $$\text{Cost (\$)} = F_L * F_T * 10^6 * [(0.057 * L + 1.8663) + (0.00129 * L) * D + (0.000486 * L + 0.000007) * D^2] \quad (45)$$

where FL = location factor, FT = terrain factor, L = pipeline length [km], and D = pipeline diameter [in]

The IEA GHG PH/6 model assumes a friction factor of 0.015 (1.5×10^{-2}).

In 2005, the IEA published two additional studies, which looked at the costs and potential of CO_2 transport and storage; the IEA GHG 2005/2 looked at European situation and the IEA GHG 2005/3 targeted the North American region. The IEA GHG 2005/2 model used the same IEA GHG PH4/6 model equations for calculating the pipeline cost but expressed in euros. In addition, a change of sign on the final constant (from +0.000007 to -0.000007) for the ANSI #1500 equation, and thirdly, deletion of the location factor term, F_L, most probably because it is dedicated to Europe [in the IEA GHG PH4/6 study F_L = 1.0 for Europe].

The adapted capital cost equation for Europe thus becomes:

$$\textbf{Pipeline Capital Cost (€)} = F_T * 106 * [(0.057 * L + 1.8663) + (0.00129 * L) * D + (0.000486 * L - 0.000007) * D^2] \quad \textbf{(46)}$$

where F_T = terrain factor, L = pipeline length [km], and D = pipeline diameter [inches]

To compute the CO_2 pipeline costs for North America (basically USA and Canada), similar to the MIT model, the study used historical cost data for natural gas pipeline construction and concluded that, on the average, construction cost for CO_2 pipelines would be **$25,889/in/km**.

The Parker model

Like the Ogden model, the Parker model was originally developed for hydrogen pipeline cost calculations (Parker, 2004). Similarly to the McCoy, MIT and the GHG 2005/3 models, Parker used historical natural gas pipeline costs to develop the equations for his model.

Similar to McCoy, Parker model goes beyond simply reporting a cost in $/in/km but provides equations for the four major pipeline cost categories, namely; materials, labour, ROW and miscellaneous costs.

The equations involved are as follows:

Materials Cost C_{mat} ($) = [330.5 * D^2 + 687 * D + 26,960] * L + 35,000 **(47)**

Labour Cost C_{labor} ($) = [343 * D^2 + 2,074 * D + 170,013] * L + 185,000 **(48)**

Miscellaneous Cost C_{misc} ($) = [8,417 * D + 7,324] * L + 95,000 **(49)**

ROW Costs C_{ROW} **(\$) = [577 * D + 29,788] * L + 40,000** **(50)**

Total Capital Cost **Cost (\$) =** $C_{mat} + C_{Labour} + C_{Misc} + C_{ROW}$**= [673.5 *** D^2 **+ 11,755 * D + 234,085] * L + 355,000** **(51)**

where D = pipeline diameter [in], and L = pipeline length [miles]

The McCollum & Ogden model

The McCollum and Ogden model (2006) is basically an average of Ogden, MIT, Ecofys, IEA and Parker models. The group looked at the said models in the context of the following scenarios:

- Pipeline diameter against CO_2 mass flow rate.
- Pipeline Capital Cost against CO_2 mass flow rate.
- Levelized CO_2 transport cost against CO_2 mass flow rate.

McCollum and Ogden observed that:

- The Ogden, MIT, Ecofys, IEA and Parker models exhibit the same trend; the total capital cost increases with pipeline diameter and the CO_2 mass flow rate.
- The levelized cost of transporting the CO_2 decreases with the increasing mass flow rate.
- The IEA GHG 2005/3 model estimates the highest total pipeline capital cost trend and also the most expensive levelized CO_2 transport cost trend for pipe lengths lower than 100 km.
- The MIT model estimates the lowest levelized CO_2 transport cost trend.

From the average trend-paths of the models for estimating costs, McCollum & Ogden (2006) developed a unified regression equation to calculate the total CO_2 pipeline cost as a function of CO_2 mass flow rate and pipeline length. McCollum & Ogden model capital cost equation is thus given by:

Pipeline Capital Cost [$/km] = (constant) * Lexponent = (9970 * $m^{0.35}$) * $L^{0.13}$ (52)

where m = CO_2 mass flow rate [tonnes/day], and L = pipeline length [km].

The McCollum and Ogden model uses a friction factor of 0.00375 (3.75×10^{-3}).

Comparative assessment of the models

The formulae of the models were used to construct **Table 13**

All distances were assumed in kilometres to enable the models in their original formulations to be compared.

With the exception of the MIT model, the other models do not assume uniform **cost per inch per km** for all pipeline diameters, i.e., cost per inch per km for say 10 inch-pipeline differs from that of 18 inch pipeline and that is the reason for the ranges in **Table 13.** For the MIT model, average total CO_2 pipeline capital cost per inch per km is estimated at $20,989 (≈ $21,000). Some of the differences among the cost estimates are apparently caused by the data availability to the various authors.

Some worked with data for pipelines below 100 km and extrapolating to cover longer distances.

Table 13. Comparative Summary of the various CO_2 Pipeline Models

	MIT	Ecofys	IEA GHG PH6	IEA GHG 2005/3	Parker	Ogden	McCollum & Ogden	McCoy
Date Published	2003	2003	2002	2005	2004	2004	2006	2008
Cost \$ per inch per km 10-18 inch; <100 km	21,000	41,500 - 42,500	17,500 - 19,000	54,000 – 56,000	25,500 - 27,500	44,000 - 45,000	35,000 - 35,500	21,000 - 36,500
Cost \$ per inch per km >18 inch; 100-500 km#	21,000	42,000 – 43,500	19,500 – 37,000	25,000 - 36,500	26,000 - 26,500	59,500 - 62,500	35,000 - 38,000	21,000 - 23,000
Annual O&M factor of capital cost	≤3% per year	2.1% per year	0.6-3% per year	2% per year	Not Available	4% per year	2.5% per year	≤6% per year
Friction factors	0.00015	0.015-0.02	0.015		Not available	~ 0.0021	0.00375	Not available

#Decided on 100-500 km because found most proposed industrial projects to be within this distance range

Reliability of the cost models in light of 2006-2008 high costs was also compared as shown in **Table 14**.

Table 14. Comparative summary of the possible strength of the various models for estimating total pipeline costs before and after 2006 using natural gas pipeline cost range as benchmark.

		Reliability							
	cost	**MIT**	**Ecofys**	**IEA GHG PH6**	**IEA GHG 2005/3**	**Parker**	**Ogden**	**McCollum & Ogden**	**McCoy**
Cost $ per inch per km	**Before 2006**	Fair	High	Fair	High	Good	High	Fair	Good
10-18 inch; <100 km	**2006-2008**	Too Low	Low	Too Low	Good	Too Low	Fair	Too Low	Too Low
Cost $ per inch per km	**Before 2006**	Fair	High	Good	Fair-Good	Good	Good	High	Good
>18 inch; 100-500 km	**2006-2008**	Too Low	Low	Low	Low	Too Low	Good	Low	Too Low

'Good' ≡ $20,000-$30,000 before year 2006 (and above $55,000 between 2006-2008);
'Fair' ≡ $12,000-$19,000 or $31,000-35,000 before 2006, (and above $45,000-$54,000 from 2006-2008);
'Low' ≡ below $12,000 before 2006 (and $40,000 - $45,000 between 2006-2008)
'Too Low' ≡ below $40,000 between 2006-2008
'High'≡ Above $35,000 before year 2006 (and above $200,000 between 2006-2008).

McCoy (2008) indicates that for a reference 16 inch 60-km pipeline, labour accounts for around **50%** of the total capital cost, whilst material cost, ROW and miscellaneous costs account for about **20%, 10% and 20%** respectively.

McCoy (2008) estimates that the material capital cost of a 16-inch 100-km pipeline was $67,459 per km. Based on his findings, the cost per km of a 16-inch pipeline would be about $339,000, or, almost **$21,000 per inch per km** (in 2004 dollars) {*If Material cost (20%) capital cost per km is $67,457, then Miscellaneous cost (20%) would be about $68,000 and Right of Way (10%) about $34,000 and Labour (50%) would be about $169,500 bringing the total to $339,000. Dividing by 16 yields about $21,000 per in per km*.}

The cost per km agrees fairly well with the construction cost of the 12 inch to 14-inch 330-km Weyburn CO_2 pipeline from North Dakota, (US) to the Weyburn EOR project in Saskatchewan (Canada) built in 1997-2000, which was $330,000 (IPCC, 2005).

The Parker model could be used to test McCoy's findings for further confirmation, by varying the costs of labour, materials, ROW, and miscellaneous costs in the Parker model set of equations. By varying the various cost parameters, etc., **Table 15** is obtained.

For instance, if Labour and Material costs are doubled (i.e. 100% each) while leaving the Miscellaneous and ROW costs the same (i.e. 0% each), the Total Capital Cost of the pipeline increases by 73.5% (*See row 7 of Table 15).*

Table 15. Percentage change in total CO_2 pipeline capital cost against changes in cost categories for the Parker model.

Row	Labour Cost change	Material Cost change	ROW Cost change	Miscellaneous Cost change	Total Capital Cost change
1.	0%	0%	+100%	0%	10.5%
2.	0%	+100%	0%	0%	12.5%
3.	0%	0%	0%	+100%	16.0%
4.	0%	0%	+100%	+100%	26.5%
5.	0%	+100%	+100%	+100%	39.0%
6.	+100%	0%	0%	0%	61.0%
7.	+100%	+100%	0%	0%	73.5%
8.	+100%	+100%	+100%	0%	84.0%
9.	+100%	0%	+100%	+100%	87.5%
10.	+100%	+100%	0%	+100%	89.5%
11.	+100%	+100%	+100%	+100%	100%

From **Table 15**, Labour cost is the most significant influencing factor on the Total Capital Cost of Pipeline in the United States and thus in agreement with findings of McCoy (2008). It is followed by Miscellaneous costs, then Material cost; whilst ROW has the least influence on the Total Capital Cost.

Mohitpour et al. (2003) reports that material cost would account for 40% of the total pipeline cost for most pipeline projects whilst construction would account for about 50%.

Summary of other uniqueness among the models are as follows:

- McCoy model utilizes only discrete line-pipe sizes in accordance with NPS (nominal pipeline sizes) as used by the industry.

- MIT model uses continuous line-pipe sizes based on a simple slope factor ($/in/km) independent of the pipeline diameter and, the equation is linear.
- Ogden model is a direct function of CO_2 flow rate and pipeline length.
- The McCoy and the Parker models use non-linear equations.
- Ogden and Parkers models were originally developed for hydrogen pipelines.
- Almost all the models were developed using historical natural gas pipeline construction costs.
- Except for McCoy (2008) and McCollum & Ogden (2006), these models date before years 2006-2008.

Introducing cost escalation factors

To derive escalation factors for the cost models, $\boldsymbol{\eta}$, $\boldsymbol{\gamma}$, $\boldsymbol{\alpha}$, and $\boldsymbol{\beta}$ are defined as escalation factors for the cost categories as follows:

$\boldsymbol{\eta}$ is Labour escalation cost factor and it is the ratio of the Average Cost of Labour at current year, over Average Cost of Labour in the base year, i.e.

$$\eta = \frac{\text{average cost of labour in current year}}{\text{average cost of labour in base year}} \qquad \boldsymbol{\eta > 0} \qquad \textbf{(53)}$$

For instance, if labour cost was $25,000 per inch per km in 2006, but in 2007 it increased to $50,000 per inch per km, $\boldsymbol{\eta}$ = 2. If it was the same in 2007, $\boldsymbol{\eta = 1}$.

For base year **a** and number of years, year **n,** $\boldsymbol{\eta_n}$**:**

$$\eta_n = \frac{\text{average cost of labour in year (n)}}{\text{average cost of labour in year}(a)} \qquad \boldsymbol{\eta_n > 0} \qquad \textbf{(54)}$$

γ is Material escalation cost factor, and it is the ratio of the Average Cost of Material at current year, over Average Cost of Material in the base year, i.e.

$$\gamma = \frac{\text{average cost of material in current year}}{\text{average cost of material in base year}} \qquad \boldsymbol{\gamma > 0} \qquad \textbf{(55)}$$

For base year **a** and number of years, year **n, γ_n**

$$\gamma_n = \frac{\text{average cost of material in year (n)}}{\text{average cost of material in year}(a)} \qquad \boldsymbol{\gamma_n > 0} \qquad \textbf{(56)}$$

α is Miscellaneous escalation cost factor and it is the ratio of the Average Cost of Miscellaneous expenses at current year, over Average Cost of Miscellaneous expenses in the base year.

For base year **a** and year **n**, **α_n**

$$\alpha_n = \frac{\text{average cost of Miscellaneous in year (n)}}{\text{average cost of Miscellaneous in year}(a)} \qquad \boldsymbol{\alpha, \alpha_n > 0} \qquad \textbf{(57)}$$

β is ROW escalation cost factor and it is the ratio of the Average Cost of ROW of the same terrain or productivity factors (features) at current year, over Average Cost of ROW of the same terrain or productivity factors (features) during the previous year.

For base year **a** and year **n**, **β_n**

$$\beta_n = \frac{\text{average cost of ROW year (n)}}{\text{average cost of ROW in year}(a)} \qquad \boldsymbol{\beta, \beta_n > 0} \qquad \textbf{(58)}$$

Recalling that only the McCoy and the Parker models provide equations for the four major pipeline cost categories. One has the option to plug ***η, γ, α,*** and

β in either the McCoy model equations or the Parker model equations. Then simplify the equations to obtain one general capital cost equation with the escalation factors in it.

Assuming opting for the Parker model, plugging the ***η, γ, α,*** and ***β*** therefore into the Parker model equations become:

Material Cost $\gamma\ C_{mat}\ (\$) \equiv \gamma\ \{[330.5 * D^2 + 687 * D + 26{,}960] * L + 35{,}000\}$ **(59)**

Labour Cost η $C_{labour}\ (\$) \equiv \eta\ \{[343 * D^2 + 2{,}074 * D + 170{,}013] * L + 185{,}000\}$ **(60)**

Miscellaneous Cost $\alpha\ Cmisc\ (\$) \equiv \alpha\ \{ [8{,}417 * D + 7{,}324] * L + 95{,}000\}$ **(61)**

ROW Cost $\beta\ C_{ROW}\ (\$) \equiv \beta\ \{[577 * D + 29{,}788] * L + 40{,}000\}$ **(62)**

Escalated total capital cost *Ć* then becomes:

$$Ć\ (\$) = \gamma\ C_{mat} + \eta\ C_{labour} + \alpha\ C_{misc} + \beta\ C_{ROW} \quad \textbf{(63)}$$

For year n, $Ć_n\ (\$) = \gamma_n\ C_{mat} + \eta_n\ C_{labour} + \alpha_n\ C_{misc} + \beta_n\ C_{ROW}$

$$Ć\ (\$) = \gamma\ \{[330.5 * D^2 + 687 * D + 26{,}960] * L + 35{,}000\} + \eta\ \{ [343 * D^2 + 2{,}074 * D + 170{,}013] * L + 185{,}000\} + \alpha\ \{ [8{,}417 * D + 7{,}324] * L + 95{,}000\} + \beta\ \{ [577 * D + 29{,}788] * L + 40{,}000\} \quad \textbf{(64)}$$

$$Ć\ (\$) = \gamma\ 330.5 * D^2 L + \eta\ 343 * D^2 L + \gamma\ 687 * D L + \eta\ 2{,}074 * D L + \alpha 8{,}417 * D L + \beta\ 577 * D L + \gamma\ 26{,}960 * L + \eta\ 170{,}013 * L + \alpha 7{,}324 * L + \beta 29{,}788 * L + \gamma\ 35{,}000 + \eta\ 185{,}000 + \alpha\ 95{,}000 + \beta\ 40{,}000 \quad \textbf{(65)}$$

$$= [\gamma\ 330.5 + \eta\ 343\ ] * D^2 L + [\gamma\ 687 + \eta\ 2{,}074 + \alpha\ 8{,}417 + \beta\ 577] * D L + [\gamma\ 26{,}960 + \eta\ 170{,}013 + \alpha 7{,}324 + \beta\ 29{,}788] * L\ \Gamma\ 35{,}000 + \eta\ 185{,}000 + \alpha\ 95{,}000 + \beta\ 40{,}000 \quad \textbf{(66)}$$

Simplifying the ***Ć*** becomes

$$Ć\ (\$)) \equiv f(\mathrm{D}) = pD^2 + qD + r + k \qquad D > 0 \quad \textbf{(67)}$$

where

$$p = [\gamma\ 330.5 + \eta\ 343] * L \tag{68}$$

$$q = [\gamma\ 687 + \eta\ 2074 + \alpha\ 8417 + \beta\ 577] * L \tag{69}$$

$$r = [\gamma\ 26{,}960 + \eta\ 170{,}013 + \alpha\ 7{,}324 + \beta\ 29{,}788] * L \tag{70}$$

$$k = \gamma\ 35{,}000 + \eta\ 185{,}000 + \alpha\ 95{,}000 + \beta\ 40{,}000 \tag{71}$$

Table 16 is the corresponding total pipeline cost per inch per km given by **Equation 67** (the modified Parker model) when the escalation factors of the cost categories are varied. It shows the variation of escalation factors of the pipeline cost categories against the total pipeline cost per inch per km.

Table 16 Variation of escalation factors of the pipeline cost categories against the total pipeline cost per inch per km.

Escalation Cost ratios of the categories X- Axis					Cost $ per inch per kilometre
X	η	γ	α	**β**	**Y-Axis**
1	1	1	1	1	44,734
2	2	1	1	1	62,078
3	2	2	1	1	80,448
4	2	2	2	1	108,368
5	2	2	2	2	147,968
6	2	1	2	2	100,348
7	2	1	1	2	72,428
8	2	1	2	1	80,248
9	1	2	2	2	130,624
10	1	1	2	2	83,004
11	1	1	1	2	55,084
12	1	2	1	1	63,104
13	1	1	2	1	62,904
14	1	2	2	1	91,024

Where:

η =1, γ=1, α=-1, β=1 means no significant change in costs from the previous year.

η =2, γ=1, α=1, β=1 means labour cost has doubled from the previous year whilst other cost components remained the same from the previous year.

η =2γ=2, α=1, β=1 means both labor and material costs have doubled from the previous year, whilst ROW and miscellaneous costs remained the same.

η =2, γ=2, α=2, β=2 means all cost components have doubled from the previous year, etc.

From **Table 16**, the cost range falls between $44,734-130,624 per inch per km with mean being about $88,000 per inch per km.

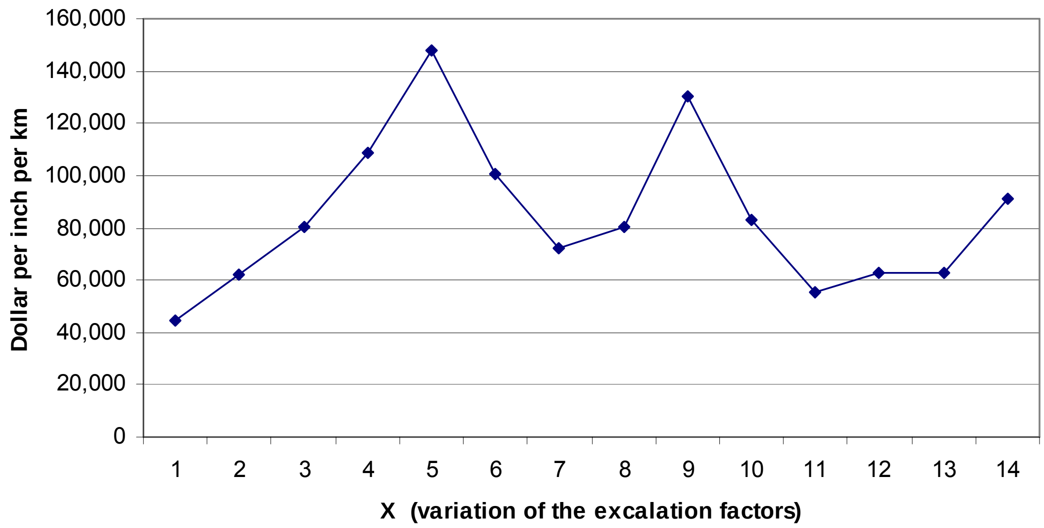

Figure 27. Total capital cost of CO_2 using the modified Parker model

From **Figure 27**, there is no significant increment in cost when

- there is no escalation in any of the cost categories (lowest cost)

- Significant cost escalations occur when more than one cost categories of the pipeline increase in cost significantly.
- Highest escalations occur when cost category increases include labour and material costs.

Using the model to estimate the pipeline cost and comparing with cost data at FERC

Using the cost range and a weighted mean pipeline diameter of 22 inches and distance of 1,613 km (Table 11), the total capital cost of the proposed pipeline network would fall between $1.59-4.64 billion.

The average range of cost per inch per km of largely natural gas onshore pipeline cost quotations submitted by the industry to US FERC (2009) between 2006-2008 was $37,823-123,466. The mean is about $64,000 per inch per km.

To avoid multiphase flow, CO_2 pipelines are usually operated at much higher pressures than comparable natural gas pipelines. This means that the required pipe wall-thickness for a CO_2 pipeline would be larger than a comparable natural gas line and consequently would have higher material cost, about 10-20% over natural gas pipeline of the same cost indices (Asante, personal communication, December 10, 2008). This could contribute to large variations among forecasted costs using the models for new CO_2 pipeline projects, since most of the CO_2 cost models were developed based upon natural gas pipelines.

The mean cost of the proposed CO_2 pipeline network, $88,000 per inch per km is about 27% higher than the FERC mean of about $64,000 per inch per km for 2006-2008 pipeline cost quotations but falls within the “$44,734-130,624” per inch per km. Both show significant compared to those of the existing models (*refer to Table 13*).

Accounting for cost escalation in the levelized CO_2 transport cost models

Besides total capital costs of the pipelines, the models also provide equations that take care of the cost of CO_2 transport through the pipelines. The selected models with their CO_2 transport cost equations are discussed here.

MIT model

The MIT model calculates levelized CO_2 transport cost as follows:

Levelized Cost: C_{lev} (\$/tonne CO_2) =

Total Annual Cost (\$/yr) / { m * CF * 365 days } **(72)**

Total Annual Cost (\$/yr) =

{(\$20,989/in/km) * D * L * CRF} +{(\$3,100/km/yr) * L} **(73)**

where D = pipeline diameter [in], L = pipeline length, and CRF = Capital Recovery Factor, m = CO_2 mass flow rate [tonnes/day, CF = Plant Capacity Factor.

Equations 72 and **73** combined give:

C_{lev} = {(\$20,989/in/km) * D * L * CRF} + {(\$3,100/km/yr) * L} / { m * CF* 365 days} **(74)**

where 365 days = 8760 hours, capital cost is \$20,989, O&M is Operation and Maintenance which is\$3,100/km/yr.

Without the constants, the levelized CO_2 transport cost equation of the MIT model becomes

C_{lev} = {(total capital cost \$/in/km) * D * L * CRF} + {(Annual O&M) * L} / { m * CF * 365 days } **(75)**

IEA models

The levelized CO_2 transport cost equation of the IEA GHG PH4/6 model is given by:

Levelized Cost: C_{lev} (\$/tonne CO_2) = Total Annual Cost (\$/yr) / (m * CF * 365 days) (76)

Total Annual Cost (\$/yr) = (Total Capital Cost * CRF) + Total Annual O&M Costs (77)

where CRF = Capital Recovery Factor; m = CO_2 mass flow rate [tonnes/day], CF = plant capacity factor

Combining **Equations 76** and **77** become:

C_{lev} ={ (Total Capital Cost * CRF) + Total Annual O&M Costs} / (m*CF*365 days). (78)

The levelized CO_2 transport cost equation of the IEA GHG 2005/2 model is given by:

Levelized Cost (€/tonne CO_2) = C_{lev} = 1000 * [{Total Annual Cost / (m * (31,536,000) * CF)} + {COE * Pp * L / (3.6 * 10^6)}] (79)

Total Annual Cost (€/yr) = Annual Capital Cost + Annual Pipeline O&M Costs + Annual Booster Station O&M Costs (80)

where 1000 = kg/tonne, m = CO_2 mass flow rate [kg/s], CF = plant capacity factor, COE = cost of electricity [€/kWh], Pp = pump power use [J/km/kg CO_2], L = pipeline length [km]

IEA (2002) considered booster stations in its models

The levelized costs of CO_2 transport of the IEA GHG 2005/3 model is given by:

Levelized Cost (\$/tonne CO_2) = C_{lev} = (L + 10) x 1.17 * (Levelized Capital cost +Annual O&M Cost) (81)

where L = pipeline length, 10 = extra pipeline distance at injection site, 1.17 is Straight line distance adjustment factor

Factoring in cost escalations

Equations 81 and **82** stand out different because they take into account booster pumps and cost of energy (COE) used by the pump which are not considered by the other models.

Equations 73, 76 and **79** are basically the same and follow a universal economic levelized cost calculation. It can thus be summarized as:

$$\mathbf{C_{lev} = \{ (\acute{C} * CRF) + Total\ Annual\ O\&M\ Costs\} / (m * CF * 365\ days)} \quad \mathbf{(82)}$$

where $\acute{C}$ *is the total capital cost, all cost escalations captured*

$$\mathbf{C_{lev} = \{(\acute{C}\ \$/in/km) * D * L * CRF\} + \{(Annual\ O\&M) * L\} / \{ m * CF * 365\ days\}} \quad \mathbf{(83)}$$

For cases where the capital cost has been given as **capital cost per inch per km**, the levelized costs of CO_2 transport

Further, the pipeline industry has a high proportion of fixed costs, since the owners negotiate their own ROW either by purchasing or leasing land and then constructing the pipeline and related facilities along the ROW resulting in significant economies of scale.

Very high fixed costs could result in long depreciation period. Technical lifetime for a pipeline is estimated at 40 – 50 years. Acceptable economic lifetime ranges from 20 – 30 years.

Figure 28 shows transportation cost per tonne of CO_2 for the three different pipeline diameters used for illustration in **Table 12** as a function of length (without booster stations), assuming an economic life of 20 years, using **Equations 82** and **83**.

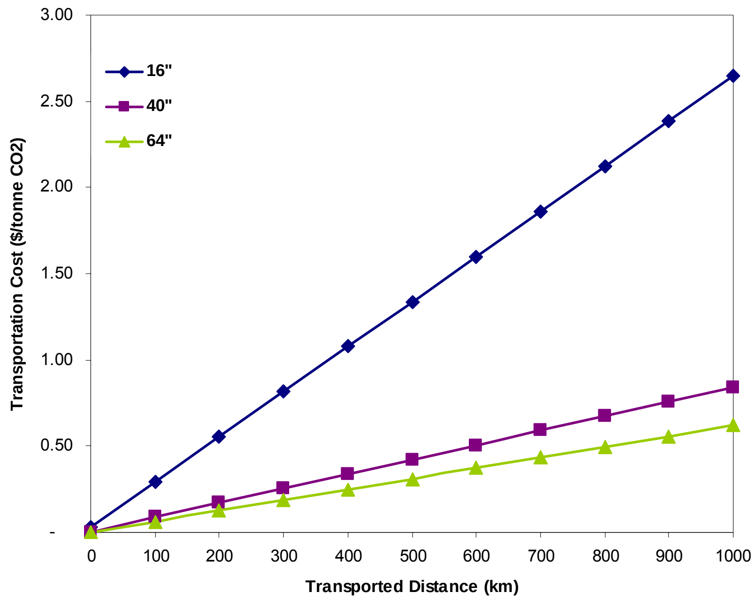

Figure 28. CO_2 Levelized transport costs for different pipeline diameters.

As observed in **Figure 28** for pipeline without booster stations, increases in pipeline diameter generate lower transportation costs for CO_2.

Booster stations

Booster stations or pumps add to the fixed cost, but it is needed depending upon the pressure drop. Also, they are required for pipelines in mountainous or hilly terrains. Furthermore, the use of booster pumps allows smaller diameter pumps to be used.

Booster stations however could be expensive and consequently increase the total pipeline cost. Should the need be in order to maintain the dense state of the fluid, Capital cost of pumping stations for CO_2 pipelines is given by (IEAGHG, 2002).

$$\textbf{\textit{Cost (\$)}} = (7.82*\boldsymbol{P}+0.46)*10^6 \quad \textbf{(85)}$$

*Where **P** is installed power in MW*

Quotations from two literature sources are as follows:

- \$2,011 per kW for CO_2 pipeline (Odenberger & Svensson, 2003).
- \$7,820 per kW for CO_2 pipeline (McCoy, 2008).

Cost of post-combustion CO_2 capture from power plants

Basic generation cost considerations

Total cost of power generation may be expressed as follows:

Total Cost of power Generation= Capital investment cost of plant+ Fuel cost+

Operation & Maintenance Cost **(86)**

Annual cost of power generation= Annualized investment cost+ Annual Fuel cost
+ Annual Operation & Maintenance cost **(87)**

Average Generation cost= Annual cost of generation+ Annual Power Generation **(88)**

Average generation cost ≈ Levelized generation cost **(89)**

Generation cost and pollution penalties

The basic power generation cost increases when pollution limits are violated. The basic pollutants considered are the sulphur oxides (SOx), nitrogen oxides (NOx) and particulate matter (PM). With climate change concerns, CO_2 emissions would be penalized in some countries.

Thus, if emission penalty fees are charged for limit violations, the total annual generation cost $\mathbf{C_{t1}}$ then becomes sum of costs of basic electricity generation ($\mathbf{C_e}$), and the penalties for emitting SOx**,** NOx, PM, CO_2 and **n** pollutants into the environment:

$$\mathbf{C_{t1} = C_e + C_{SOx} + C_{Nox} + C_{PM} + C_{co2} + C_n} = \sum_{i=1}^{i=n} Ci \qquad \textbf{(90)}$$

Where $\mathbf{C_e}$ is the cost of basic power generation; $\mathbf{C_{SOx}}$ is cost penalty due to excess SOx, $\mathbf{C_{Nox}}$ is cost penalty due to excess NOx, $\mathbf{C_{PM}}$ is cost penalty due to excess PM, $\mathbf{C_{co2}}$ is cost of emitting excess CO_2, $\mathbf{C_n}$ is cost of emitting excess n pollutants

For CO_2 capture where the salable by-products including the captured CO_2 are sold to offset costs, the net cost equation becomes

$$\mathbf{C_{net} = [C_e + C_{SOx} + C_{Nox} + C_{PM} + C_{co2} + C_n] - [S_{co2} + \ldots + S_n]} \qquad \textbf{(91)}$$

*where $\mathbf{S_{co2}}$ is revenue from CO_2 sales; $\mathbf{S_n}$ is revenue from sales of **n** by- products*

$$\mathbf{C_{net}} = \sum_{i=1}^{i=n} Ci - \sum_{i=1}^{i=n} Si \qquad \textbf{(92)}$$

For a co-generation system where both electricity and heat are generated

$$\mathbf{C_{net} = C_{heat} + C_e} \qquad \textbf{(93)}$$

where $\mathbf{C_{heat}}$ is average cost of heat production

Net average power generation cost then becomes:

Net average power generation cost= Annual C_{net}÷ Annual gross power generation **(94)**

Equation 94 excludes seasonal and diurnal differences.

Expression **Equation 94** in differential equation form becomes:

$$\partial.Cnet \big/ \partial.\varepsilon = \varphi net \qquad \textbf{(95)}$$

where φ is Levelized generation cost ≈ average generation cost, ε is electricity generated.

$\partial.Cnet$ and $\partial.\varepsilon$ are differentials of the net generation cost and the electricity generated.

For a given technical availability of a power plant, the net revenue $\mathbf{R_{net}}$ is

$$\Re net = \int_{CF=0}^{CF=100} \varphi net.*\,\partial.\varepsilon \qquad \textbf{(96)}$$

where CF is a capacity factor ranging from 0-100% for a power plant of given technical availability

Comparative analysis of the power plant emissions

Average electrical conversion efficiencies of gas-fired and coal-fired power plants in Texas have been 33% and 35% respectively (BEG, 2006b). Even though, turbine efficiencies of the gas plants could be as high as 47% (low-heating value), averagely low capacity factors over the years have been responsible for its overall relatively low average conversion efficiency.

Post-combustion supercritical ‘capture ready’ power plants and IGCC (Integrated Gasification Combined Cycle) plants based on coal with their better conversion efficiencies of 44-47% have been proposed as the new generation of power plants to replace conventional pulverized coal plants. It however remains an open question as to how competitive these new fossil fuel plants fitted with CO_2 capture would be. Johnson and Keith (2004) had look at the impact of CO_2 emission on the future carbon economy. Key issues raised included potential, high capital cost of new generation coal plants, cost of CO_2 emission capture and ability to finance the projects.

IGCC has the potential to reduce CO_2 due its higher combustion efficiencies compared to both conventional and supercritical coal fired plants. It also has the added advantage of producing abundant hydrogen, a cleaner fuel for power generation and vehicular transport but no life-size power plant operational yet (US DOE/NETL, 2007).

However, whilst gas turbines to burn hydrogen efficiently than natural gas are not yet available, it might be possible to burn a mixture of hydrogen and crude natural gas since the total density and energy content of the mixture would fall within the natural gas flash point range and heat content (Donaldson & Mukherjee, 2006).

High gas prices in Texas and in most parts of the United States between 2005 and mid-2008 resulted in lower capacity utilization factors for plants originally built for base load operation between late. For natural gas plants, fuel costs account for about 70% of operational expenses. Therefore, as generation cost became too costly to dispatch, the plants were ran much less often, sometimes as low as 10%.

On the other hand, there may be an opportunity for using existing natural gas combined cycle (NGCC) to burn a mix of natural gas and gasified coal. Less impurities in natural gas and the virtually absence of SO_x in natural gas reduces the capital cost associated with flue gas clean up. It also offers the opportunity for the natural gas plants to increase their capacity utilization in times of high natural gas price since part of the energy would be used for the capture (Donaldson & Mukherjee, 2006).

Appendix 3 is a spreadsheet model is developed out of **Equations 86-96** to calculate and compare the power generation costs for existing power plants including post-combustion CO_2 capture.

When IGCC and the supercritical coal power plants are compared with other power plants, existing coal plants retrofitted for CO_2 capture provide the least generation cost until CO_2 emission penalty of about \$20/tonne is introduced. Wind takes over as the least generation cost. Discount rates considered for the United States in this analysis are 6% and 15% (Figure 29).

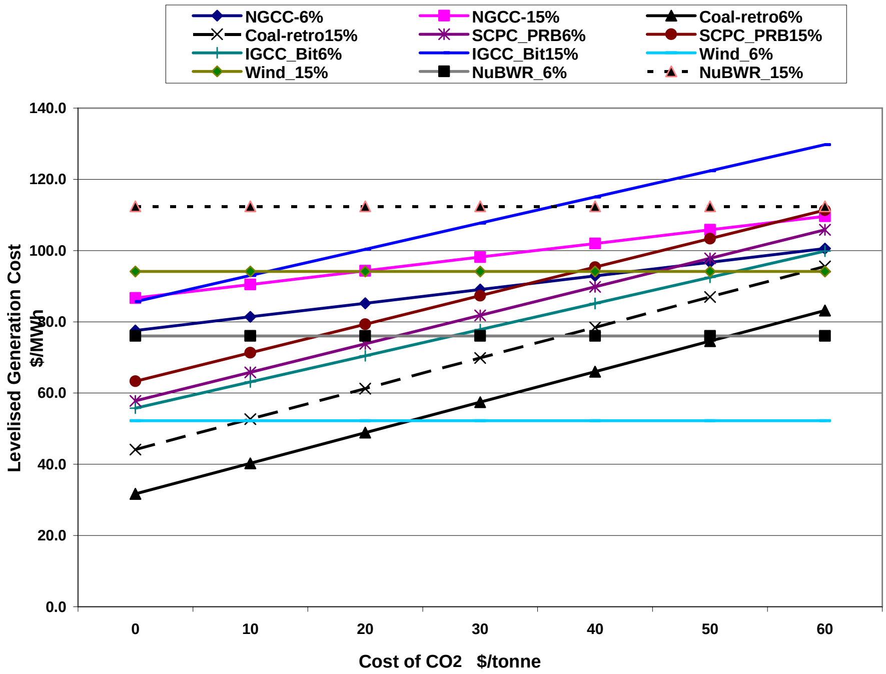

Figure 29. Comparing impact of CO_2 cost on levelised generation cost for different power plant technologies

{NGCC is natural gas combined cycle; coal-retro is existing coal power plant retrofitted to capture CO_2; SCPC is supercritical pulverised coal plant; NuBWR is supercritical nuclear plant based on Boiling Water Reactor; Wind is wind power}.

As quality check, the model outputs were compared with similar work done by EPRI (2008) and found them to be consistent with each other (Figure 30).

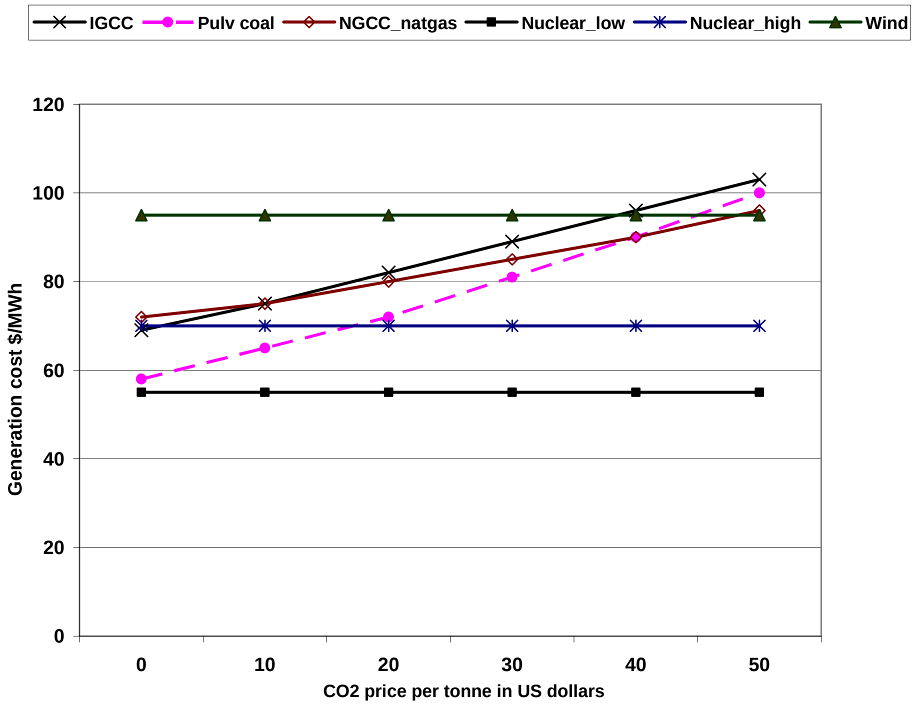

Figure 30. Impact of CO_2 cost on livelised costs of electricity generation

{For the NGCC based on natural gas data, EPRI used specific capital cost of $750/kW but $8/mmBTU as fuel price whilst $1000/kW but $7/mmBTU as fuel price were used in this analysis. . For the nuclear plants, EPRI used $3,260-3,720/kW as specific capital cost whilst the range used here was $3,500-4,000/kW range taking cognizance of $5,000-8,000/kW capital requirements findings published by US FERC (2008). U.S. FERC data on nuclear capital costs were significantly greater than those of EPRI.}.

Parameters and data used for the generation cost analysis are found in **Appendix 2**. From the results, it was deduced that:

- Electricity generation cost increases for all carbon-based power plants if they are made to capture CO_2.

- Capture-ready' or supercritical coal plants are more expensive to operate if they operate without capturing CO_2 because they are optimized for capture mode. Their generation costs, however, are reduced and become lower than 'no-capture' mode when they are made to capture CO_2. The reduction is very significant if the captured CO_2 and the by-products like the sulphates and ash/slag could be sold to generate revenues to deflate operational cost.
- Conventional pulverized coal plant without capture is less expensive for business-as-usual operations but becomes less competitive in carbon constrained economy.
- All the coal plants with capture become relatively favourable when part of their existing power capacity is used to meet the CO_2 capture requirements as opposed to adding new generation capacity for capture.
- For coal plants with additional investment in generation capacity to meet capture requirements, fixed costs due to this additional investment form the highest percentage of the capture costs.
- Existing pulverized coal plants which have at least 20 years more technical life span and could be upgraded to CO_2 capture would produce the least cost generation option as compared to building a new pulverized coal plant. This is largely because low specific investment cost and fuel price lead to low generation cost.

- Generation costs of existing pulverized coal plant upgraded to CO_2 capture would be more expensive than its existing conventional non-capture counterpart but revenues from the CO_2 if salable for say, EOR, could reduce the net generation cost significantly and in some cases create profit depending on the selling price of the CO_2.
- Natural gas fired plants without capture becomes economically favourable with increasing discount rate but that comparative advantage weakens with increasing fuel price. Natural gas-fired plant would become less favourable as the price of natural gas rises above $6 per Gigajoule (GJ).
- Integrated coal gasification combined-cycle (IGCC) power plants without CO_2 capture would be the most expensive thermal plants to build and operate in a carbon constrained economy. Williams et al. (2007) arrived at about the same conclusion saying that IGCC plants would require more primary materials to build and also costs are uncertain since no full-scale commercial IGCC plant has been constructed.

Ranking of the power plants according to generation cost

The mean values of the generation costs at discount rates of 6%, 10% and 15% were used to rank the power plants using economic lives of 20 and 30 years (Table 17).

Table 17. Generation cost range for typical central power plants with CO_2 capture at different discount rates; *minimum value corresponds to 30 year economic life and maximum value corresponds to 20 year economic lifetime*

	Generation Cost Range (cents/kWh)							
Discount Rate	*6%*		*10%*		*12%*		*15%*	
Power Plants	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**
Existing Pulverized Coal – *capture retrofit*	3.2	3.4	3.7	3.9	4.0	4.1	4.4	4.5
New conventional Pulverized Coal	4.0	4.4	4.9	5.2	5.4	5.7	6.0	6.4
Super critical pulverized –*low sulphur coal*	4.3	6.4	5.1	7.6	5.6	8.2	6.3	9.3
IGCC -*Bituminous coal*	5.6	8.6	6.8	9.7	7.5	11.3	8.6	12.8
Super critical pulverized – *bituminous coal*	5.9	6.5	7.4	7.8	8.1	8.5	9.3	9.6
IGCC – *Lignite coal*	6.4	7.1	8.0	8.6	8.9	9.4	10.3	10.7
Natural gas combined cycle *(without capture)*	6.8	6.9	7.1	7.2	7.3	7.5	7.6	7.8
Natural gas combined cycle *(with capture)*	8.8	9.0	9.2	9.4	9.5	9.8	9.9	10.1
IGCC – *Petroleum Coke*	7.3	8.0	9.0	9.6	10.0	10.5	11.4	11.8

Refer to Appendix2 for basic data used for the computations.

The results indicate that retrofitting existing appropriate coal plants with capture still maintain their advantage as providing the least cost generation. IGCC plants with capture fired with petroleum coke tend to be the most expensive.

Both existing natural gas and coal plants would however require additional land size to accommodate the retrofit comparable to their current occupied areas.

A coal IGCC would take significant land space due to additional lands for coal handling and storage, waste treatment and sludge storage. It could be about 3-4 times that required by natural gas CCGT of the same capacity or about twice land size requirement of existing coal-fired plant (Donaldson & Mukherjee, 2006).

Williams et al. (2007) at Duke University deduced that as coal price increases, IGCC with capture is likely to become more cost competitive than convention sub-critical coal power plant with capture due to its higher conversion efficiency and consequently lower emissions. The CO_2 capture cost is also relatively less expensive with IGCC.

Power plant CO_2 supply options for Texas Gulf Coast

Eight (8) to eleven (11) million tonnes of CO_2 would be required for EOR only, but 26-35 million tonnes is required for simultaneous EOR and sequestration.

In order to meet the CO_2 requirements, the following CO_2 supply options were considered:

1. Supplying the CO_2 requirements from only coal plants comprising three scenarios:
    a. 75% capture with coal plants each less than 1000 MW.
    b. 30% capture with coal plants including the 3,969 MW plant at Fort Bend County (*refer to Table 8*).
    c. 45% capture with coal plants including the LCRA 1690 MW plant at Fayette County *(refer to Table 8*).
2. Supplying the CO_2 from only gas-fired power plants at 90% capture.

The assumptions are as follows:

- 20-year economic life time at 10% rate of return for the capture units.
- the power plants maintain their contractual power supply to the grid. *This however means the existing power plants would have to expand their installed capacities to meet the energy requirements of the capture plants.*

Option One

OPTION ONE: Five coal plants all located in the Texas Gulf Coast of total installed capacity of 2,602 MW but at 75% CO_2 capture (Table 18).

Table 18. Selected Coal Plants at 75% CO_2 capture for EOR in Texas Gulf Coast

Installed Capacity MW	CO_2 captured Tonnes	Equivalent Capacity MW	Estimated construction time/months	Initial Investment cost $m	Annual Cost $m
570	2,997,397	180	12 – 18	241	100
410	1,961,860	129	12 -16	173	72
546	2,693,183	173	12 -16	231	96
892	4,018,588	282	12-16	378	157
184	789,986	58	Less than 12	78	33
Total 2,602	***12,461,013***	***822***	***≤18***	***1,100***	***424***

Coal plant would require larger land area for CO_2 capture technology than gas plant and the assumption is that there is enough land area to accommodate the CO_2 capture plant.

The total equivalent installed capacity for CO_2 capture for power plants listed in Table 18 is 822 MW, about 32% of total power plants installed capacity. Cost per tonne of CO_2 captured is about **$37**.

Option Two

OPTION TWO: Six coal plants all located in the Texas Gulf Coast including the 3,969 MW plant at Fort Bend County (*refer to Table 8)* but each at an average of 30% CO_2 capture. Total installed capacity is 6,571 MW (Table 19).

Table 19 Selected Coal Plants at 30% CO_2 capture for EOR in Texas Gulf Coast

Installed Capacity MW	CO_2 captured Tonnes	Equivalent Capacity MW	Estimated construction time/months*	Initial Investment cost $m	Annual Cost $m
570	1,091,495	72	Less than 12	96.6	39.96
410	785,111	51.6	Less than 12	69.6	28.74
546	1,045,538	69	Less than 12	92.4	38.28
892	1,708,094	112.8	12 -16	151.2	62.58
184	352,342	23.4	Less than 12	31.2	12.9
3,969	7,600,255	501	24-36	671.4	278.4
Total 6,571	***12,582,836***	***830***	***≤36***	***1,112***	***461***

The total equivalent installed capacity for 30% CO_2 capture is 830 MW, about 13% of total power plants installed capacity. Cost per tonne of CO_2

captured is about **$37**. *The assumption is that there is adequate land area to accommodate the CO_2 capture plant at the 3,969 MW plant at Fort Bend County.*

Option Three

OPTION THREE: Six coal plants at an average of 45% CO_2 capture. It includes the LCRA 1690 MW power plant at Fayette County but excluding the 3,969 MW capacity plant at Fort Bend. Total installed capacity is 4,292 MW (Table 20).

Table 20. Selected Coal Plants at 45% CO_2 capture for EOR in Texas Gulf Coast

Installed Capacity MW	CO_2 captured Tonnes	Equivalent Capacity MW	Estimated construction time/months	Initial Investment cost $m	Annual Cost $m
570	1,637,243	108	Less than 12	145	60
410	1,177,666	77	Less than 12	104	43
546	1,568,307	104	Less than 12	139	57
892	2,562,142	169	16 – 18	227	94
184	528,513	35	Less than 12	47	19
1690	4,853,728	320	18-24	429	178
Total 4,292	***12,327,599***	***814***	***≤24***	***1,091***	***452***

The total equivalent installed capacity for 45% capture is 814 MW, about 19% of total power plants installed capacity. Cost per tonne of CO_2 captured is about **$37**. *The assumption is that there is adequate land area to accommodate CO_2 the capture plant at the LCRA 1,690 MW plant at Fayette County.*

Option Four

OPTION FOUR is wholly natural gas. Most of the natural-gas-fired plants in Texas had relatively low capacity factors (many under 10%) as of 2006. This means that they produced widely varying amounts of CO_2, depending on electricity demand. Also, for a given megawatt-hour of power generated, natural-gas-fired plants emit 50-60% of the CO_2 effluent than a comparable coal-fired plant. Thus gas-fired plants did not operate as many hours per year as coal- or lignite-fired plants and did generate substantially lower amounts of CO_2.

However, higher capacity factor utilization is likely in the long term as operations of coal fired plants are constrained by their higher GHG emissions.

High capacity factor of the large gas plants would however imply higher and significant CO_2 emissions and for that matter would be compared to undertake mitigation measures just as the coal plants.

For these reasons, Option Four looks at natural gas-fired plants which could possibly blend with coal power plants as alternative CO_2 fluid supply in the future.

The following six gas-fired plants are selected due to their proximity to earmarked CO_2-EOR candidate oil fields. The gas plants are able to meet the CO_2 supply requirements for the EOR (Table 21). There is significant reduction in CO_2 emissions after retrofitting a natural gas combined cycle plant (NGCC) for CO_2 capture. Significant reduction however could mean less CO_2 for EOR activities.

In any case, the selected gas plants of installed capacity totalled 4000 MW at an average of 90% CO_2capture could meet the supply requirements for EOR

Table 21 shows the installed capacities of the selected gas-fired thermal power plants.

Table 21 Selected natural gas-fired power plants in the Texas Gulf Coast

Installed Capacity MW	Plant Owner	County	Nearest Oil field	Annual CO_2 emissions tonnes	Expected CO_2 emissions After retrofit tonnes
647	CP&L	Willacy	Willmar West	≤ 2.6 million	1.9 million
461	CP&L	Jackson	West Ranch	≤ 2.0 million	1.4 million
543	Energy Gulf	Montgomery	Conroe	≤ 2.2 million	1.6 million
652	Formosa Plastics	Refugio	Tom O'Connor	≤ 3.1 million	2.0 million
875	Reliant Energy	Harris	Tomball	≤ 3.5 million	2.6 million
1,422	Reliant Energy	Chambers	Oyster Bay	≤ 5.7 million	4.3 million
Total 4,600			***Total***	***≤ 19.1 million***	***13.8 million***

Table 22 shows that cost per tonne of CO_2 captured is however about **$66** which is more than those of the coal plant options.

Table 22. Selected Gas-fired Plants at 90% CO_2 capture for EOR in Texas Gulf Coast

Installed Capacity MW	CO_2 captured Tonnes	Equivalent Capacity MW	Estimated construction time/months	Initial Investment Cost $m	Annual Cost $m
647	1,753,511	148.3	12 – 16	163.1	115.4
461	1,249,410	105.7	Less than 12	116.2	82.3
543	1,471,648	124.5	Less than 12	136.9	96.9
652	1,767,062	149.4	12 – 16	164.4	116.3
875	2,371,440	200.6	12 – 16	220.6	156.1
1,422	3,853,929	325.9	16 – 24	358.5	253.7
Total 4,600	***12,467,000***	***1,054.4***	***≤24***	***~1,160***	***~821***

Cost of the gas-fired and the coal fired plants are compared in **Table 23**.

Table 23. Comparing the selected CO_2 supply options

Option	CO_2 Source	CO_2 Percent Capture	Equivalent Capacity MW	CO_2 captured Tonnes	Initial Investment cost $m	Annual Cost $m	Net CO_2 Emitted Tonnes
One	Coal	75%	822	12,461,013	1,100	424	4,153,671
Two	Coal	30%	830	12,582,836	1,112	461	29,359,951
Three	Coal	45%	814	12,327,599	1,091	452	15,067,065
Four	Gas	90%	1,054	12,467,000	1,160	821	1,385,222

The capture equivalent of about 1,054 MW and the annual cost of the gas-fired plants are higher compared to those of the coal-fired options (Table 23). The cost per capture of the gas option (~$66 per tonne) is also higher.

The gas option nonetheless emits the least CO_2 whilst the coal Option Two emits the most CO_2 into the environment during operation and these could have significant cost impact in carbon constrained economies (Table 24).

Table 24. Annual Cost of CO_2 capture at different cost of CO_2 per tonne penalty for the different options

Option	Initial Investment of capture unit $ million	Annual Cost of capture at different CO_2 per tonne penalty $ million						
		$0 /tonne	$10 /tonne	$20 /tonne	$30 /tonne	$40 /tonne	$50 /tonne	$60 /tonne
One	1,100	424	440	455	471	487	502	518
Two	1,112	461	755	1,048	1,342	1,635	1,929	2,223
Three	1,091	452	603	753	904	1,055	1,205	1,356
Four	1,160	821	835	849	863	876	890	904

Where no penalty is charged on CO_2 emissions, the gas option (Option 4) is the most expensive. However, as the penalty on CO_2 emissions is introduced, the larger installed capacity coal options, namely Options Two and Three become more expensive than the gas option. The Option one (coal) remains the least cost option (Figure 31).

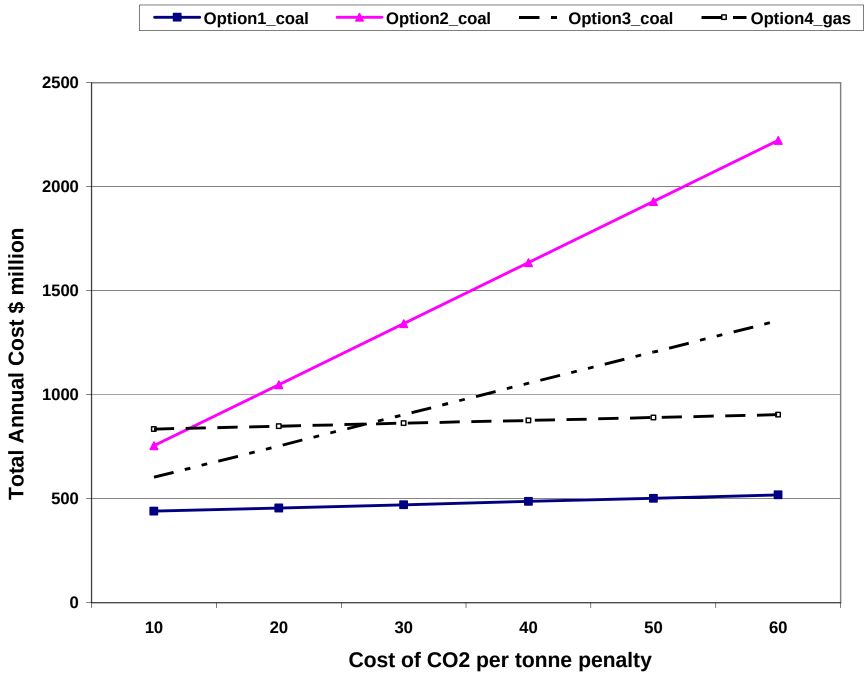

Figure 31. Operational cost of CO_2 capture for CO_2 Supply Options 1 -4

On the other hand, in an economy where there is further market for the saleable by-products, for instance, if sequestering the excess CO_2 brings in extra income, the sulphur scrubbed and the ashes are marketable, Option Two would be the most economical, followed by Option Three and then Option One. The gas option becomes worse off economically.

Sensitivity Analysis of the CO_2 Power Plant Supply Options

Sensitivity analysis was performed on the options to find out the percentage capture with the least CO_2 emission cost penalty. Each investigation starts with the minimum capture to produce adequate CO_2 for the EOR activities up to 90% capture.

In all cases, it is observed that initial investment cost of the capture plant increases as the percentage CO_2 capture goes up (Figure 32).

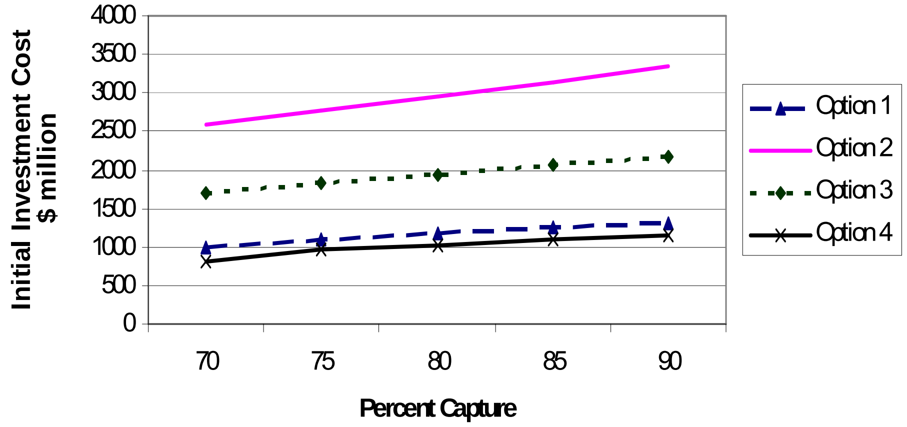

Figure 32 Comparing investment costs of CO_2 supply Options 1-4

Option One

For Option One, 75% capture provides the least annual cost at zero penalty cost for CO_2 emissions, followed by 80% capture (Figure 33).

However, the latter takes over as providing the least annual cost as

penalty for CO_2 exceeds $10 per tonne whilst the former turns out to be the most expensive after about $35 per tonne penalty.

Figure 33 shows the annual operational costs for carbon capture at different CO_2 cost penalty for the selected coal plants in Option One.

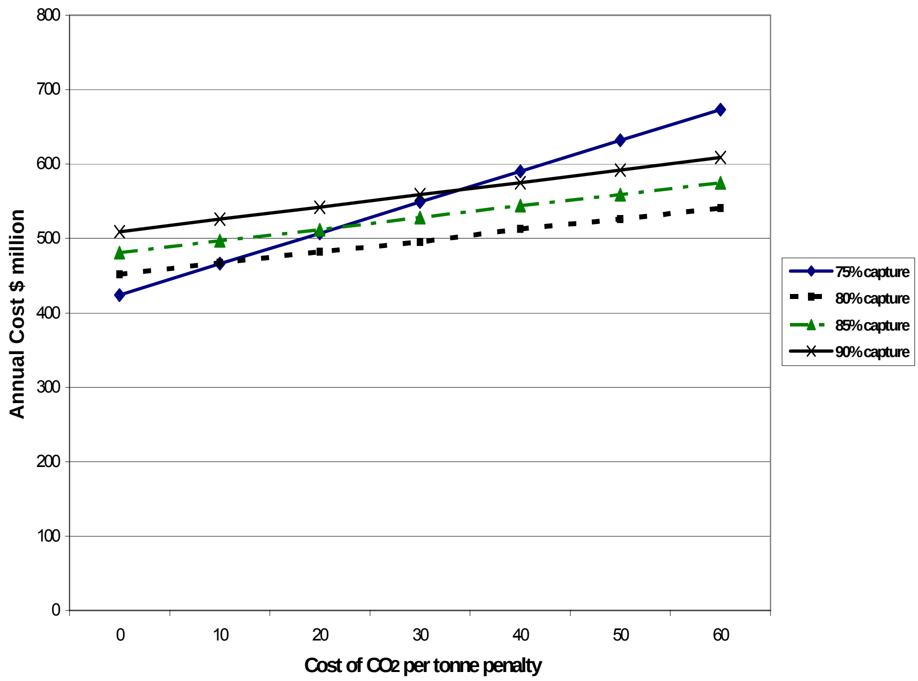

Figure 33. Comparative Annual Operational Cost for Carbon Capture for Option One

Option Two

Option Two has the lowest capture of 30% but the largest equivalent installed capacity due to the inclusion of the 3,969 MW coal plant at Fort Bend County.

30% CO_2 capture and 90% CO_2 capture are the least and most expensive annual costs respectively in a zero cost penalty economy. However the former increases in cost displacing the latter when the CO_2 penalty costs exceeds about $35 per tonne.

At CO_2 penalty cost of $60 per tonne, 90% capture becomes the least expensive. The median and optimum capture is about 60% (Figure 34).

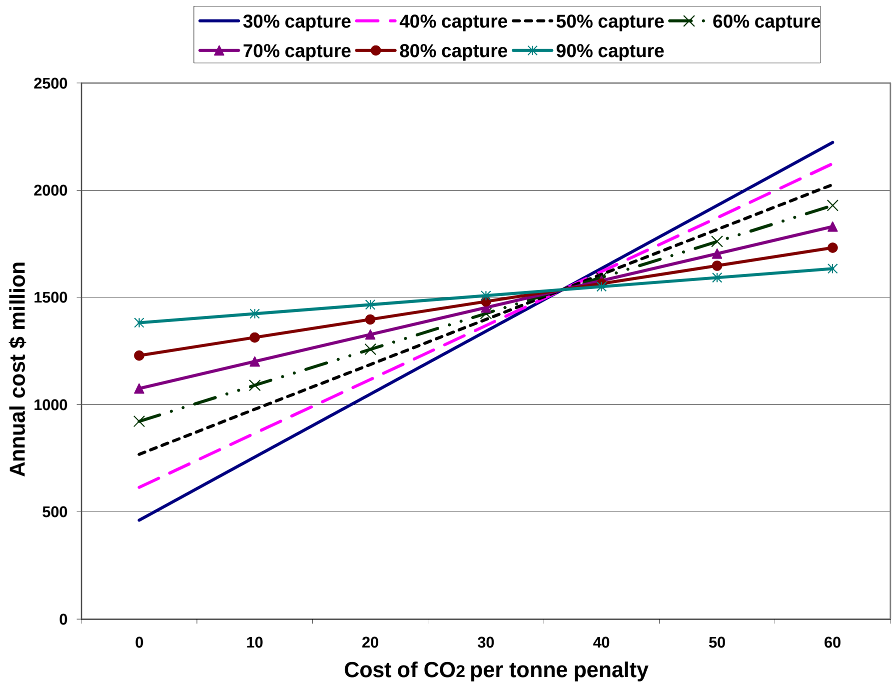

Figure 34. Comparative Annual Operational Cost for Carbon Capture for Option Two

Option Three

Option Three required only 45% CO_2 capture due to the inclusion of the 1,690 MW coal plant at Fayette County.

45% capture and 90% capture provide the least and the most expensive annual costs respectively till about $50 per tonne CO_2 penalty. Above $50 per tonne CO_2 penalty, 90% capture is the most cost competitive for Option Three (Figure 35).

Figure 35 shows the annual operational costs for carbon capture at different CO_2 cost penalty for the selected coal plants in Option Three.

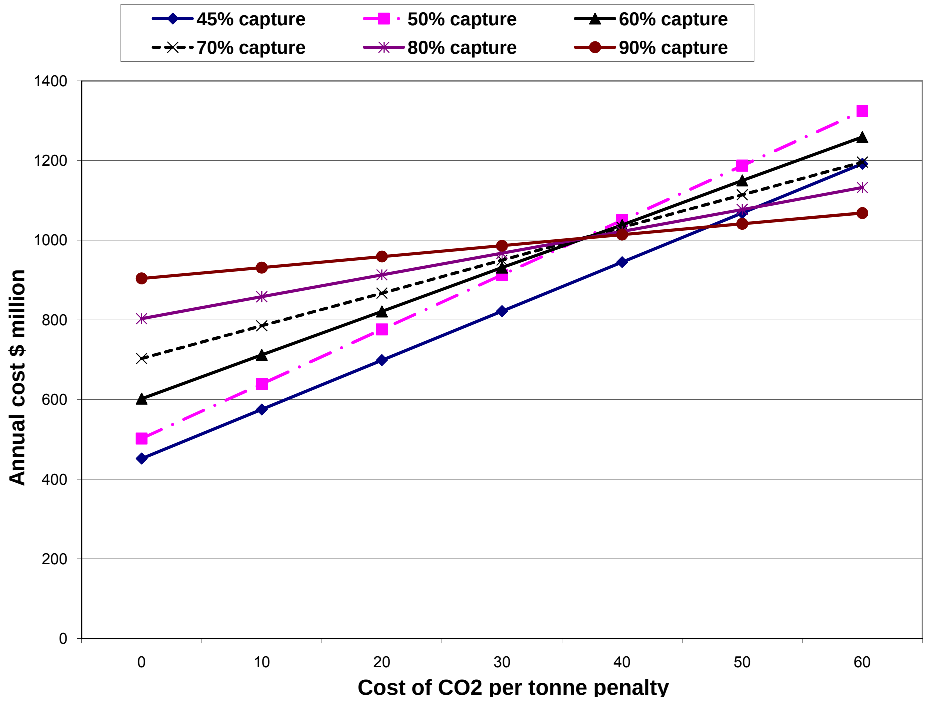

Figure 35. Comparative Annual Operational Cost for Carbon Capture for Option Three

Option Four

Option Four; the all-gas option behaves differently under the range of CO_2 cost penalty considered. There is no change over for any of the capture options. 70% capture is the most cost competitive capture option whilst 90% capture provides the most expensive annual cost. Thus the higher the capture the more expensive it is, for CO_2 per tonne penalty below \$60 (Figure 36).

For this option and CO_2 penalty range being considered, 90% capture however provides about the same level of CO_2 fluid as supplied by the coal options (Option One to Option Three).

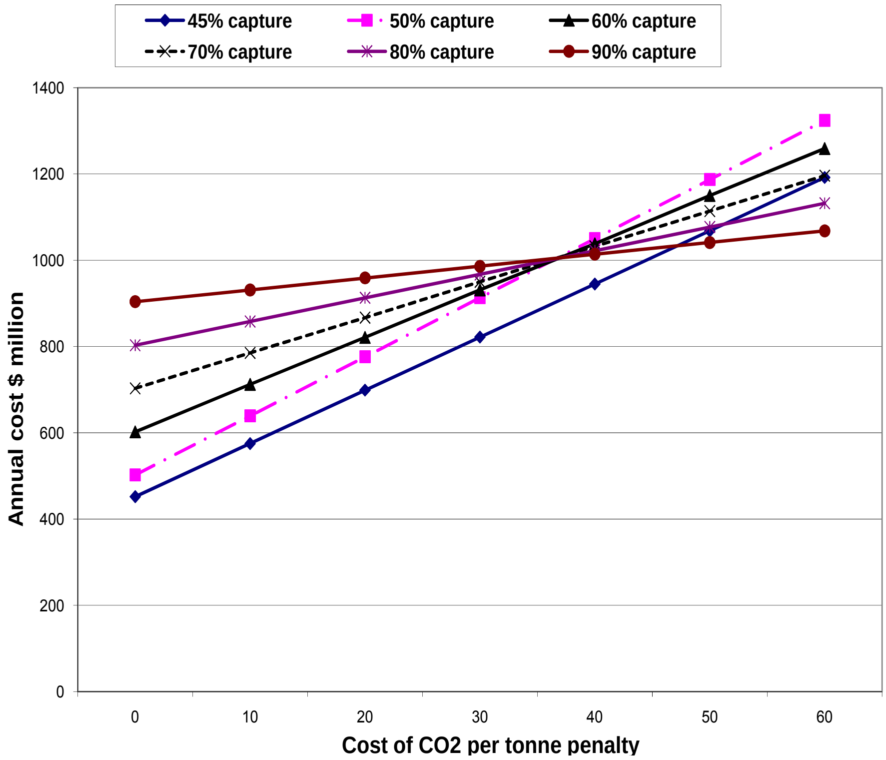

Figure 36. Comparative Annual Operational Cost for Carbon Capture for Option Four

Impact of CO_2 Capture on Power Generation Cost

From analysis of Options One to Four, two conclusions could be drawn:

- Lower CO_2 percentage capture does not necessarily translate into lower operational cost in a carbon constrained economy.
- The annual cost reduces with higher percentage capture as the CO_2 per tonne penalty charge increases.

For the options discussed the optimum CO_2 percentage captures are as follows:

- 80% capture for Option One

- 60% capture for Option Two
- 45% capture for Option Three
- 90% capture for Option Four.

The generation cost of the power plants would increase with carbon capture. It would double for most coal power plants (Figure 37). The percentage incremental costs are higher for the coal plant options than the gas-fired option (Option 4) but their generation cost would still be lower than average generation cost of gas fired plants with carbon capture. It would be about half the generation costs of gas-fired plants (without capture) for natural gas price above \$6 per GJ.

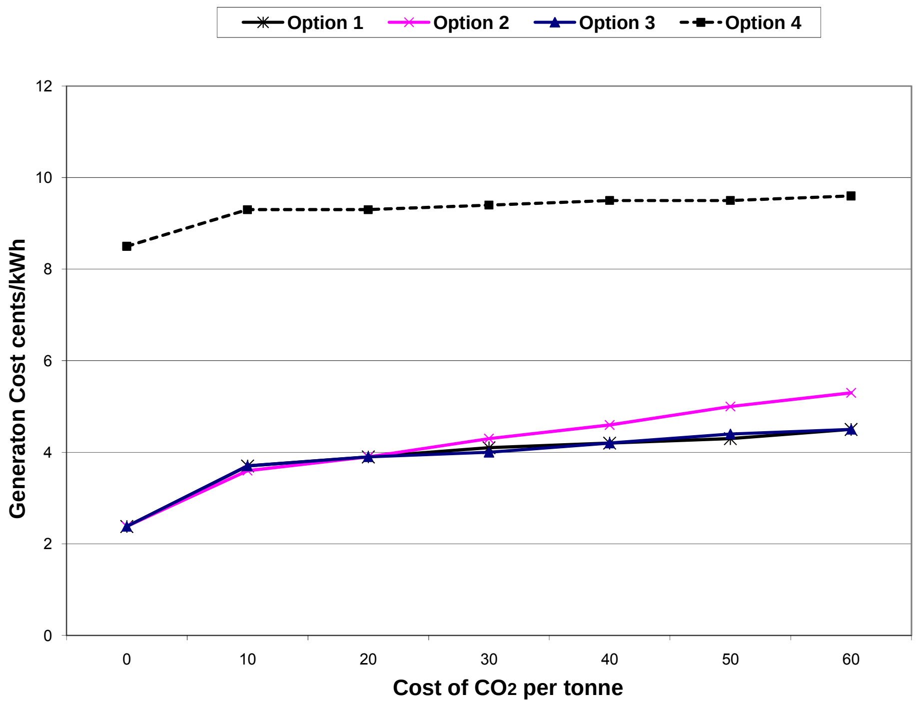

Figure 37. Comparative Generation Costs for the CO_2 Power Plant Sources with carbon capture

Table 25 shows that even though the carbon options have higher percentage incremental costs, compared to the gas fired plants, they would still provide the most competitive electricity generation costs.

Table 25. Percentage incremental costs for capture options at different CO_2 penalty cost

Carbon dioxide Cost penalty $/tonne	**Percentage incremental cost Capture Options**			
	Option 1	Option 2	Option 3	Option 4
0	0	0	0	0
10	*55.5*	*51.3*	*55.5*	*9.4*
20	*63.9*	*63.9*	*63.9*	*9.4*
30	*72.3*	*80.7*	*68.1*	*10.6*
40	*76.5*	*93.3*	*76.5*	*11.8*
50	*80.7*	*110.1*	*84.9*	*11.8*
60	*89.1*	*122.7*	*89.1*	*12.9*

Estimating the potential job creation

To determine estimate the potential jobs to be created, we need first of all to determine the estimated the cost of developing the CO2-EOR candidate fields.

Assuming a consultant organizes a seismic survey of a field to locate potential places to drill. To drill a new well, one has to obtain permit from the U.S Environmental Protection Agency (B. Asante, personal communication, December 10, 2008). The drilling starts after the permit is secured. When oil is hit, the well is brought into completion by fixing in pipes and measuring probes. Old wells are rehabilitated, usually called work-over. Injection wells are also drilled where the CO_2 are injected. At times, some of the old oil wells are rehabilitated and used as injection wells.

U.S. EPA permit fee is between \$18,000-20,000. Consultant's fee averages \$140,000 per visit and maximum of 10 visits are assumed. Shooting seismic is estimated at \$20,000 per line. Maximum of five shootings is assumed (B. Asante, personal communication, December 10, 2008).

Cost of drilling a new well onshore ranges from \$100,000-\$150,000 per 300 metres depth. Cost of work-over or rehabilitating existing well is about half the cost of drilling a new well (B. Asante, personal communication, December 10, 2008).

Well completion expenses are estimated at \$400,000 per well. In total, cost of a new oil well from drilling to readying for production ranges from \$1.3-3.0 million and that of workover well would range from \$300,000-500,000 in the Gulf Coast (B. Asante, personal communication, December 10, 2008).

The existing (BEG, 2006a) database however, did not indicate the number of existing wells and the new producing wells to be drilled. This introduces uncertainties in the cost computation and therefore would widen the cost range.

Recycling cost of CO_2 recycling battery is estimated at \$110,000 per reservoir (Advanced Resource International, 2006).

Oil production by the CO_2-EOR is expected to be about 1.7 billion barrels using today's technology (Advanced Resource International, 2006). Higher global oil market price could however induce higher oil production.

The capital cost of field development is estimated at $17.7-19.7 billion yielding about $10-11 per barrel as breakeven development price for the crude oil (Table 26). The low-bound cost if field development excludes fields deemed uneconomic, namely Old Ocean, Fig Ridge and Willamar (Table 26). The high-bound cost if the entire selected fields are developed.

Drilling costs include the cost of physically drilling an injection well, running casing, hanging tubing, and installing any borehole equipment (e.g., chokes and packers) (American Petroleum Institute, 2002).

Table 26. Estimated development and operational costs of the candidate-EOR fields

Oil Fields	Estimated no. of oil wells	Drilling& associated costs $'000	Cost of Injection wells $'000	Cost of Work-over wells $'000	CO_2 Recycling cost $'000
Conroe	585	6,535	30,360	233,207	333
Hastings	1,253	7,320	82,614	649,698	333
Webster	160	2,340	12,081	93,234	111
T O'Connor	286-357	17,027	109,417	848,767	777
Giddings	NA	5,378	81,597	848,000	333
Hull	776	6,158	121,845	1,302,858	444
Seeligson	666	60,392	220,824	1,703,366	2,775

Table 26 *(Continued)*

Oil Fields	Estimated no. of oil wells	Drilling& associated costs $'000	Cost of Injection wells $'000	Cost of Work-over wells $'000	CO_2 Recycling cost $'000
Oyster Bayou	21	3,090	1,832	16,072	111
Goose Creek	NA	1,980	5,002	34,777	111
Gt Borregos	275	44,175	42,913	524,298	1,221
Pearsall	NA	2,160	34,217	251,780	111
West Ranch	273	13,759	307,453	3,662.329	999
Liberty,South	NA	2,700	27,846	230,294	111
Pierce Junction	NA	2,100	22,505	162,514	111
White Point,	136	4,634	12,691	96,958	111
Old Ocean	Esteemed to be uneconomic (*though cost is 1,808,946,907*)				
Orange	155	4,140	43,277	419,626	222
Tomball	754	20,450	89,464	674,620	999
Big Wells	79	5,554	104,439	1,092,810	333
Stowell	124	12,299	253,327	2,986,445	666
Willamar	*Esteemed to be uneconomic (though cost is 117,449,810)*				
Fig Ridge	*Esteemed to be uneconomic (though cost is 47,530,476)*				
Gillock	36	13,165	22,287	200,268	444
Portilla	106	9,576	29,436	249,964	444
T-C-B	162	2,730	12,850	106,835	111
Refugio-Fox	76	11,295	256,746	3,000,535	666
TOTAL	***5,338-5,409***	***258,957***	***1,925,023***	***15,730,588***	***11,877***
GRAND TOTAL			**$17,711,216,329 (*19,668,968,272*)**		

In the case where the pipeline pressure is insufficient for CO_2 injection, a compressor is added at the storage site. The total capital cost of a reciprocating compressor station has been estimated by the IEA in a European study of the pipeline transmission of CO_2 (IEA, 2002b).

Job creation

We would define total jobs to be created by an investment as:

Total jobs creation= Jobs due to capital investment+ Jobs due to O&M+

Jobs due to fuel supply **(97)**

Whilst potential jobs to be created by the capital investment would be defined as:

Jobs due to capital investment per year= Annualised investment cost X

(1-import ratio) X Specific labour input per unit investment **(98)**

where import ratio is the fraction of component of the technology that has to be imported (outside the country)

We would also define job requirement for operation and maintenance of plant is as:

Jobs due to O&M per year= Annual O & M cost X

(1-import ratio) X Specific labour input per unit O & M cost **(99)**

where import ratio is the fraction of component of labour that has to be imported during operation and maintenance.

Finally, we would define jobs to be created as a result of supplying fuel as:

Jobs due to fuel supply per year= Annual fuel supply cost X (1-import ratio) X

Specific labour input required per unit fuel cost **(100)**

where import ratio is the fraction of component of labour involved in fuel supply that has to be imported.

For the United States, most of the components of the technology are likely to be produced locally and for that matter import ratio is zero (Table 27).

Table 27. Employment datasheet for Texas Gulf Coast

	Likely Import Ratio			Specific labour input on national economy due to (Years/$)		
	Equipment	**Operation & Maintenance**	**Fuel**	**Equipment cost**	**Operation & Maintenance Cost**	**Fuel Cost**
Capture technology	0	0	0	141	15	155
Pipeline	0	0	0	NA	NA	NA
EOR fields	0	0	0	NA	NA	NA

Unfortunately, most of the data were not available at the time of finalising the thesis. We therefore sought an alternative proxy method. The employment components of the capture technology, pipeline and the EOR fields are however discussed first.

Carbon Capture technology jobs

Installing capture plants in the existing selected plants would create both temporary and permanent employment. **Figure 28** shows the number of potential new jobs to be created.

Table 28. Job-creation potential of the capture plants of the three CO_2 supply options

CO_2 Supply Options	CO_2 Source	Equivalent. Capacity MW	Initial Investment cost $m	Estimated Construction time Months	Temporary/ Construction*	Permanent / O& M#	Coal Mines@	Total job creation
					Man per year			
Option One	Coal	822	1,100	≤ 18	200-2,000	14-16	82	296 – 2,098
Option Two	Coal	830	1,112	≤ 36	200-2,000	14-16	83	297 – 2,099
Option Three	Coal	814	1,091	≤ 24	200-2,000	14-16	81	295 – 2,097
Option Four	Gas	1,054	1,160	≤ 24	100-1,000	14-21	0	118 – 1,021

* *Assumed gas-fired plant creates about half the jobs created by coal fired plants and about half the number of permanent jobs. These explain why a range is given for the various job creation lines*

O&M data was obtained from US DOE/NETL (2007).

@ *Assumed 2,000 workforce in Texas coal mines support almost 20,000 MW installed coal plant capacity. Therefore 10MW to one man-force equivalent. Adapted from U.S DOE/NETL (2007).*

New skilled but permanent jobs to the industry include chemical engineering due to the chemical units of the capture plants. Depending upon automation and level of skilled and blue-collar labour, jobs during construction would grow from a minimum of about 200 to peaks of about 2,000 per year (Table 28).

Option Three creates the most direct employment per year. Option Four which is the gas option creates the least jobs.

Pipeline construction jobs

Labour accounts for about 50% of the pipeline installed cost (McCoy, 2008). To compute the number of potential jobs to be created by the construction of the proposed pipeline network, a technique used by Page (2000) was employed. Constructing a pipeline up to its completion involves the following activities mentioned in **Table 29**.

For line-pipe of weighted average 22 inches, this crew (262-284 men) would cover about half km in 24 man hours (Page, 2000).

For one km, the following could be pursued: either

- the number of crew-men (Table 29) is doubled to 524- 568 for the 24 hour work. Or;
- double the working period to 48 hours but maintain the same number of crew-men.

24 working hours also implies working for three (3) 8-hour working days for one km. To cover 100 km would be 8 x 30 x 10 hour working day, which is equivalent to about a 10 working months *{Assuming 8 hour working day}*.

Table 29 Job creation during pipeline construction and completion process

	Description of activity	Jobs	Manpower
1	Clear and grade Right-of-Way	6	21-24
2	Layout	5	6
3	Unloading, handling, hauling, stripping pipe	6	13
4	Aligning and welding	14	30-40
5	Ditching and trenching	10	24
6	Bending and operation	10	14
7	Clearing, priming, coating and wrapping	11	21
8	Clearing, priming coating of joints only	8	13
9	Painting of pipeline	5	10
10	Lowering of pipe in trench	6	11-15
11	Valve installation	7	20
12	Cleaning and testing of pipeline	10	36
13	Trench backfilling	5	7-12
14	Clean-up operations	6	14
15	Utility operations	10	22
	Total	**119**	**262-284**

Source: (Page, 2000)

Thus 160 km would require about 12 calendar months using the same work force of 524-568. Therefore 1600 km (~1,613 km) pipeline would create 1,190 jobs and require 5,240-5,680 workforce.

Therefore, doubling the crew number keeps construction period between 12-18 months. *{It however does not mean in practice, one needs to hire that number of workforce. One with the requisite skills can handle more than one job in other field-activities}*.

Candidate EOR fields jobs

Field development would require highly (white-collar) skilled and blue-collar skilled workforce.

The highly skilled labour would include geophysicists, geologists and engineers as found in **Table 30**. The lowly skilled labour usually provides assistance in drilling and production operations, field surveys, sandblasting and paintings, etc.

Assuming 35 jobs and 63 men per field, it is expected that about 910 jobs requiring about 1,638 men crew could be created during the EOR field activities (B. Asante, Personal Communication, December 10, 2008).

{Multiplying the figure over the 26 fields yield 910 jobs and 1,638 men crew requirements}.

In the absence of the required labour statistics (*refer to Table 27*) for Texas Gulf Coast, w used numerical methods based on Page (2000) for the pipeline, and proxy data (for the capture plant and the CO_2 – EOR candidate fields).

Table 30. Estimated job creation in a typical onshore hydrocarbon upstream

Category of Labour		No. of Jobs created	Averaged number of men crew required
Highly skilled labour			
	Geophysicist	1	2
	Geologist (surface and sub-surface)	2	4
	Drilling engineer	1	2
	Technicians – Mechanics/electricians	2	4
	Production engineer	1	2
	Completion engineer	1	2
	Petrophysicist/ reservoir engineer	1	2
	Survey engineer	1	2
	Sub-total	*10*	*20*
Relatively lowly skilled labour (drilling, survey spread, etc)			
	Superintendent	1	2
	Foreman	2	2
	Drillers/roughnecks	4	8
	Driller helpers	4	8
	Compressor operator	2	4
	Generator/Pump operator	2	4
	Drivers	4	4
	Paint foreman	1	1
	Blasters and painters	2	4
	Potmen /Helpers	3	6
	Sub-total	*25*	*43*
Grand Total		**35**	**63**

Source: (B. Asante, personal communications, December 10, 2008)

Direct Job creation summary

We estimate that about 7,000–10,000 direct employment are likely to be created from construction to completion of the project as well as its operation and maintenance (Table 31).

Table 31: Estimated Total Direct employment from CO_2 capture through to CO_2-EOR field developments and operations.

Construction to Completion of facility	**Total Employment**	***% of Grand Total Employment*** *(nearest unit)*
CO Capture plant options		
Option 1	296 – 2,098	*4- 22*
Option 2	297 – 2,099	*4- 22*
Option 3	295 – 2,097	*4- 22*
Option 4	118 – 1,021	*2 – 12*
Pipeline construction	5,240-5,680	*56 – 81*
CO_2 EOR candidate fields	1,638	*17 – 23*
Total		
For CO_2 capture Option 1	7,174 - 9,416	*100*
For CO_2 capture Option 2	7,175 - 9,417	
For CO_2 capture Option 3	7,173 – 9,415	
For CO_2 capture Option 4	6,996 – 8,339	

CHAPTER FIVE

RESULTS AND DISCUSSIONS

In this thesis, a multi-source multi-sink CO_2 pipeline infrastructure is proposed for the Texas Gulf Coast. The CO_2 would come from 14 existing stationary coal and gas power plants. Integrating the individual pipelines gathering the CO_2 emissions captured from the power plants and distributing them over the oil fields for the EOR and storage create an integrated multi-source to multi-sink pipeline network. This multi-source to multiple -sink" pipeline network model allows flexibility of operations for both the CO_2 capture plants and the oil fields. Since a source is not tied to any specific oil field, the latter would not suffer when the source is shut down, and vice versa.

Cost of CO_2 capture technology and pipeline network

From the thesis, the summary of the estimated total investment costs is as follows:

- The total investment cost for retrofitting the CO_2 capture system to the 14 selected power plants could range between US $1.1-1.2 billion depending upon the CO_2 source capture option (*refer to Table 24*). Capturing the CO_2 from gas-fired power plants would be the most expensive source of CO_2 supply. The coal power plants would provide the most competitive CO_2 supply source and with the least operational cost ranging from US $440-US$518 million per annum even when $10-60 per tonne penalty is imposed on CO_2 emissions.

- The total capital cost of the pipeline network would range from US \$1.6-4.6 billion depending upon the cost escalations experienced by labour and materials. The cost tilts towards the high-side in times of doubling of labour, material, right-of-way costs and vice versa.

Potential CO_2 emission reduction to the atmosphere

The analysis shows that CO_2 captured from the 14 thermal power plants for CO_2-EOR activities with sequestration complementation would result in 29-38% reduction in the Texas Gulf Coast power plant CO_2 emissions per annum. The emission reduction lessens to 20-26% per annum during maximum power plant CO_2 emissions. On the other hand, the emission reduction drops in significance if the EOR is not complemented with CO_2 sequestration (Table 32).

Table 32. Percentage CO_2 emissions captured in relation to total annual CO_2 equivalent emissions.

CO_2 Emissions	Percentage CO_2 emissions captured – mitigated annually			
	Gulf Coast		Texas	
	EOR only	EOR + sequestration	EOR only	EOR + sequestration
Power plant	6-12%	20-38%	3-7%	13-23%
Energy related	1-2%	4-6%	<0.5%	> 0.5 but <1%
Total	**1%**	**3-5%**	**<0.5%**	**> 0.5 but <1%**

It was noted that carbon based power plants in Texas have emitted between 250 – 352 million tonnes of CO_2 annually between 2005-2007 depending upon the capacity factors of the plants operated per year (*refer to Table 1*). **Table**

32 shows that, if the project is implemented for EOR activities only, without sequestration, its impact as contribution to CO_2 mitigation in Texas would range from 3-7% annually compared to the annual emissions by the power plants and would be insignificant compared to the overall Texas CO_2 equivalent emissions.

The annual CO_2 required for EOR in the Texas Gulf Coast would range from 8-11 million tonnes for economic life time of 20-25 years and that the annual CO_2 demand could increase to 26-34 million tonnes if CO_2 sequestration is included.

Impact CO_2 capture on power generation cost

The analysis indicates that:

- Lower CO_2 percentage capture would not necessarily translate into lower operational cost in an economy where CO_2 emissions are penalised or constrained. It would depend on the installed capacity of the power plants, the CO_2 supply and the cost/fee charged for emitting CO_2 into the into the atmosphere.
- The generation cost of the power plants would increase with carbon capture. The percentage incremental costs would range from 55-122% for the coal plant options under CO_2 emission penalty of $10-60 per tonne. The higher the CO_2 emission penalty, the higher the percentage incremental cost. The percentage incremental cost for the gas-fired plants would range from 9-13%.

- Despite the higher percentage incremental cost for the coal plants with capture, their average generation cost would still be lower than average generation cost of the gas fired plants with carbon capture.
- Furthermore, the average generation cost of the coal plants with capture would also be lower than the generation costs of gas-fired plants (without capture) if natural gas price is above $6 per GJ. It is assumed that coal price is between $2-3 per GJ.
- There is additional increase in generation costs over the basic, if penalties are charged for other excess pollutant emissions such as sulphates. There is however significant reduction in generation costs, if the captured CO_2 and the by-products like the sulphates and ash/slag are sold to generate revenues to deflate operational costs. The revenue increases as the price of CO_2 per tonne increases. {*CO_2 penalty cost is assumed to equal selling price*}.
- All the coal plants with capture become relatively highly economically favourable when part of their existing power capacity is used to meet the CO_2 capture requirements. In practice however, it means reduced sale of electricity to the grid.

Impact CO_2 capture on power generation cost

The analysis suggests that the number of potential direct employment expected is estimated at about 7,000 – 10,000 jobs. Most of the employments are however expected to be temporary and would be during the construction of the capture plants, pipeline network and the development of the EOR candidate fields. There were no reliable data however to help establish the percentage of permanent employment from the total. For the CO_2 capture retrofit, those of the coal-fired plant options would create the most jobs.

CHAPTER SIX

CONCLUSIONS

The thesis involved:

- Selecting and Retrofitting 14 selected power plants to capture CO_2.
- Designing integrated pipeline network based upon the CO_2 mass flow rates from the 14 power plants to the oil fields; *the line-pipe sizes, compression pressures, and the distances between the sources and sinks.*
- Accessing the fluid- and thermo-dynamic requirements of the infrastructure.
- Estimating the percentage CO_2 captured.
- Analysing the cost of the infrastructure.
- Determining the impact on power generation cost.

A multi-source multi-sink CO_2 pipeline infrastructure comprising individual pipelines gathering CO_2 emissions captured from 14 selected thermal power plants and distributing them over the EOR candidate oil fields and eventually for geologic storage is proposed for the Texas Gulf Coast.

CO_2 source and capture

- Total power plant emission is opted for because it is the most significant among all stationary emitters; accounting for 84% of total CO_2 emissions in Texas.

- Absorption technology based on amine for CO_2 capture was selected because it was found out to be the most economically viable short-to-medium term strategy for capturing the CO_2 from power plant flue gas due to the latter's low CO_2 concentration.

CO_2 Pipeline transport

- Besides, labour, material, right-of-way (ROW) and miscellaneous costs as deduced from all the existing pipeline cost models, it is observed that total pipeline costs depend on the diameter, length and material type of the pipeline; amount and quality of CO_2 to be transported; and the delivered pressure. Investment cost goes up, when compressor stations are required to compensate for pressure drop along the pipeline. They add to the fixed cost. Compressors are avoided by using bigger diameter pipelines where applicable and avoiding mountainous terrains.
- It is observed that large diameter pipelines with high capacities would give substantially lower transportation costs per tonne than pipelines with smaller diameter and hence there is much to gain by establishing large-scale systems.
- Total capital cost of the pipeline network is estimated at \$1.6-4.6 billion depending upon the terrain of the right-of-way and the cost escalations of the cost categories. Cost drifts to the high-side for high labour and material cost regions and to lesser extent, for pipeline passing through high terrains, restricted areas and or urban centres.

- A graphical chart for selecting appropriate line-pipe diameters based upon the initial compression and pressure drops along the pipeline has been developed out of this work.

CO_2 emissions reduction

The thesis shows that implementing the entire project comprising capturing the CO_2, from the power plants, transporting it to the oil fields for eventual storage would reduce yearly emissions as follows:

- CO_2 emissions from power plants: by 6-38% in Texas Gulf Coast and by 3-23% in Texas. *Total CO_2 emissions from power plants from 2005-2007 averaged about 90 and 300 million tonnes annually for Texas Gulf Coast and Texas respectively (US EPA, 2009).*
- 1-5% of total Texas Gulf Coast emissions but less than 1% of total Texas emissions. *Total GHG emissions from 2005-2007 were about 800 million tonnes and 7 billion tonnes CO_2 equivalent for Texas Gulf Coast and Texas respectively (US EPA, 2009).*

Potential job creation

The analysis suggests that the number of potential direct employment expected is estimated at about 7,000 – 10,000. Most of the jobs are however expected to be temporary and would be created during the construction of the capture plants, pipeline network and the development of the EOR candidate fields.

Contribution of thesis to global knowledge

- Used Bernoulli's equation, CO_2 compression equations to develop a **chart** for selecting pipeline sizes **at a glance**, according to pressure drops along the pipeline (*refer to Figure 20*).
- Introduced **escalation factors** into existing **pipeline cost models** to make them **relevant at all times** (*Equations 62, 82, 83*)**.**
- Developed a **spreadsheet cost model for power plants** that incorporates costs and revenues from e**nvironmental emissions** in the total **generation costs (***Appendix 3***).**

Future Research

Possibility of retrofitting old or existing natural gas or any other sub-surface pipeline for CO_2 transport; investigating investment risks and uncertainties; and ranking the project development into order of technical and economic merits as to which of the capture –pipeline segments could be implemented first.

The United States Department of Energy (DOE) in June, 2010 has awarded $167 million to one of the selected power companies, NRG Energy, for a pilot project to demonstrate the project concept proposed by the thesis. NRG Energy (*refer to Table 8*) would provide a matching fund of the same amount to build a post-combustion CO_2 capture unit at the company's power plant southwest of Houston, Texas. A portion of the CO_2 emissions captured will be transported to a nearby oil field for enhanced oil recovery and long-term storage. As part of the programme, The Gulf Coast Carbon Center of the Bureau of Economic Geology

(BEG) of the University of Texas at Austin is receiving up to $19 million to monitor the CO_2 during and after injection (Appendix 4).

The project could be replicated elsewhere in the United States where sources and potential sinks exist. Dooley et al., (2009) reveals that between 17,000 and 37,000 km of additional pipeline dedicated to CO_2 transport might be needed in the United States before 2050, compared to the existing 6,200 km national CO_2 pipeline infrastructure.

The project could also be applied elsewhere in the world including Ghana where CO_2 sources and potential sinks exist to help in the global greenhouse gas mitigation efforts.

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APPENDICES

Appendix 1: Overview of Science of Oil Recovery and Geologic Storage

We provide a primary introduction to the petroleum industry. The industry also traditionally uses the imperial instead of the familiar S.I units. For this reason, the imperial units may be mentioned alongside the S.I units just for conformity.

Oil recovery rates

When an oil well is drilled, the amount of oil that is recoverable is determined by a number of factors including the porosity of the rock formation, permeability of the rocks, the strength of natural drivers (the gas present, pressure from adjacent water or gravity), and the viscosity of the oil. The oil occupies the pore spaces in the rock and so the larger the amount of pore spaces, the greater the oil find is likely to be. However if the pore spaces are not linked, the oil cannot flow to the surface. The greater the number of pores spaces linked the possibility of a higher flow to the surface. Also, when the reservoir rocks are "tight" such as shale, oil generally cannot flow through but when they are permeable such as in sandstone, oil flows freely (BEG, 1999).

Appendix 1 *continued*

The flow of oil is often helped by natural pressures surrounding the reservoir rocks including natural gas that may be dissolved in the oil; natural gas present above the oil; water below the oil; and the strength of gravity. Oils tend to span a large range of viscosity from liquids as light as gasoline to heavy as tar. The lightest forms tend to result in higher production rates. They are graded as APIs {*American Petroleum Institute grading*}. Oils with API below 12 (API-12) are considered very heavy. Oils with API above 30 are considered light and so API 35 is considered very light and usually "sweet". Being "sweet" means it has little or no sulphur content (Petroleum Economist, 2007).

Primary recovery

Oil flows from the subsurface reservoir rocks into wells and then gushed out to the surface due to the pressure acting on it, called *Reservoir drive*. This oil production due to the initial or pressure is called the *Primary oil recovery*.

During the *primary recovery stage*, reservoir drive comes from a number of natural mechanisms. These include:

- natural water displacing oil upward into the well,
- expansion of the natural gas at the top of the reservoir;
- expansion of gas initially dissolved in the crude oil; and
- gravity drainage resulting from the movement of oil within the reservoir from the upper to the lower parts where the wells are located.

Appendix 1 *continued*

During primary production the average oil field can produce between 5-30% of the oil in the reservoir by the natural reservoir drive, depending on the specific gravity of the crude and the kind of natural pressure drive (Petroleum Economist, 2007).

Secondary recovery

Over the lifetime of the well production, the natural pressure would fall, and at some point there would be insufficient natural underground pressure to force the oil to the surface. After natural reservoir drive diminishes, *secondary recovery* methods are applied to recover some of the remaining oil. They rely on the supply of external energy into the reservoir in the form of injecting fluids to increase reservoir pressure, hence replacing or increasing the natural reservoir drive with an artificial drive. A hot steam often pumped into the rock formation is tried first. This is called *Water flooding*. During waterflooding, new wells are drilled into the depleted oil reservoir to inject the hot steam. At times old wells are converted into water-injection wells. Other secondary recovery techniques to increase the reservoir's pressure include natural gas re-injection. Typical recovery factor from water-flood operations is about 30%, depending on the properties of oil and the characteristics of the reservoir rock. On average, the recovery factor after primary and secondary oil recovery operations is between 30-50% ((Recht, 1984; 1986).

Appendix 1 ***continued***

Tertiary recovery

Tertiary recovery begins when secondary oil recovery isn't enough to continue adequate production, but only when the oil can still be extracted profitably. This depends on the cost of the extraction method and the prevailing crude oil price. When prices are high, previously unprofitable wells are brought back into production and when they are low, production is curtailed.

Steam is injected into many oil fields where the oil is thicker and heavier than normal crude oil. Tertiary oil recovery reduces the oil's viscosity to increase oil production. Occasionally, synthetic formulations usually called *detergents* are also used to the decrease oil viscosity as a tertiary oil recovery method.

In CO_2-EOR, CO_2 is injected into the rock formation/reservoir where it dissolves in the oil to form a miscible fluid by causing the oil to swell, which results in reduced viscosity and increased density. The carbon dioxide presence in the oil in addition exerts acidic effect on the reservoir rock and in some cases vaporizes some of the residual oil to flow to the surface (Recht, 1984; 1986).

Waterflooding

Waterflooding is the production strategy of injecting water into an oil reservoir to displace and repressurize the oil. When waterflooding occurs it leaves behind the residual oil that is the target of CO_2- EOR projects.

Appendix 1 *continued*

Density and Viscosity of CO_2

Figures A1 and **A2** provide basic information on the change in CO_2 density and viscosity, very important oil recovery mechanisms, as a function of pressure.

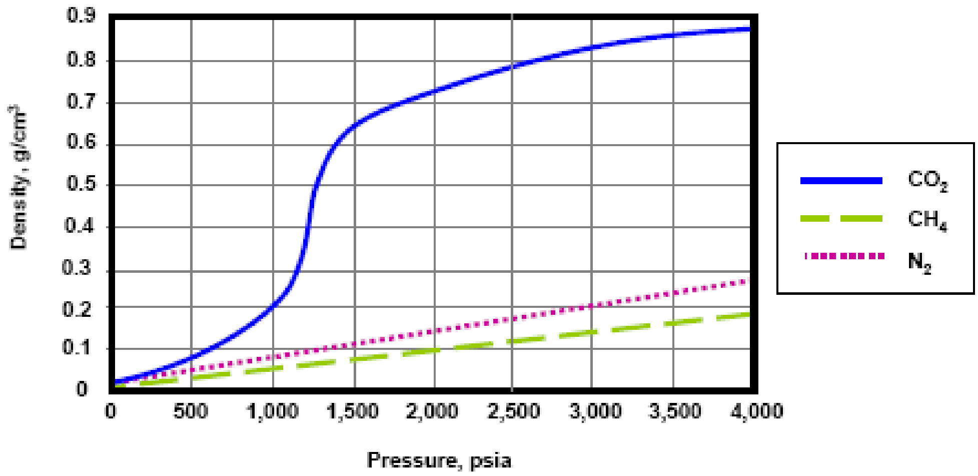

Figure A1. CO_2, CH_4 and N_2 densities at high pressures, 41°C
Adapted from Advanced Resource International (2006)

The properties of CO_2 (as is the case for most gases) change with the application of pressure and temperature.

At high pressures, CO_2 has a density close to that of a liquid and much greater than those of methane and nitrogen which are other gases associated with hydrocarbon operations. Its viscosity also decreases relatively.

Figure A2 shows the viscosity reductions that occur for a reservoir's oil with the injection of CO_2 at high pressure (Advanced Resource International, 2006).

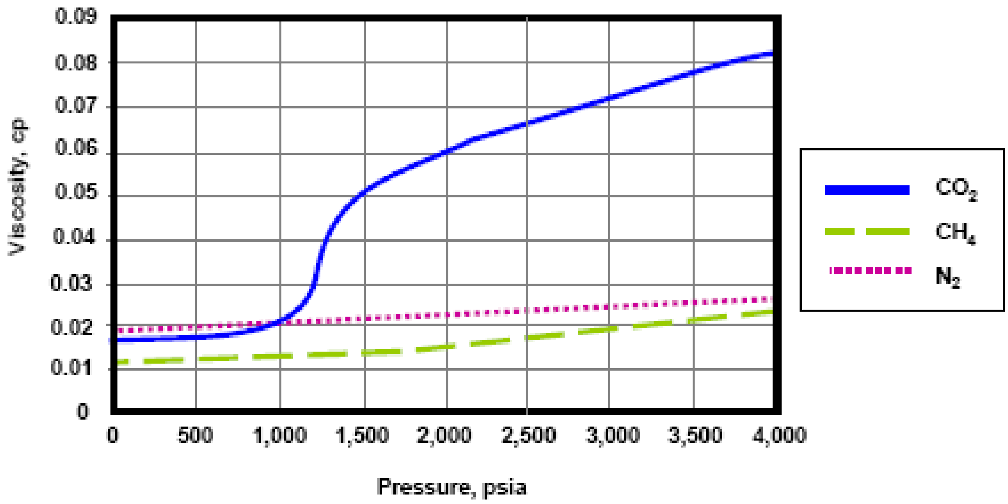

Figure A2. CO_2, CH_4 and N_2 viscosities at high pressures, 41°C.
Adapted from Advanced Resource International (2006)

These qualities allow the CO_2 to mix with the residual oil and eventually swelling the latter when the two are brought into contact.

Oil and gas gravity

Oil gravity, a measure of the density of oil and the hydrocarbon component makeup, plays an important role in CO_2 flooding for oil recovery and sequestration because oil character affects CO_2 solubility. Most of the benefits CO_2 conveys for oil recovery, such as oil swelling and viscosity reduction, are highly influenced by the oil's gravity (API-*American Petroleum Institute standard*) (Klins & Bardon, 1991).

There are widely varying screening criteria related to oil API and CO_2 flooding. In a general sense, the API gravity must not be less than 12° API nor greater than 55° API.

Appendix 1 *continued*

Very heavy oils or very volatile oils have historically resulted in poor sweep efficiencies (Klins & Bardon, 1991).

Porosity and permeability

Porosity, the void space within rock that can hold oil, gas, or water, is the fundamental contributor to reservoir storage capacity. Porosity values vary widely for different depositional systems, but they generally range between 11-30% (Beike & Holtz, 1996). The type of porosity, as well as the amount, is important. Well-connected porosity of similar size is the best type for both CO_2 EOR miscibility projects and sequestration. Greater porosity, with all other properties being equal, increases the viability of sequestration.

Permeability, the ease at which fluid flows through a rock, determines the fluid dynamics of the reservoir. High permeability would allow high volumes of CO_2 to be injected into a single well, thus reducing cost. High permeability would also allow CO_2 to move out more quickly into the reservoir, which is also favourable to sequestration (Beike & Holtz, 1996).

Reservoir depth

Reservoir depth is a very important factor because start-up and field operating costs increase with depth. Deeper wells result in greater drilling costs and greater operating costs to inject and pump out fluids.

Appendix 1 *continued*

Reservoir temperature increases with depth, resulting in a higher minimum miscibility pressure. The effectiveness of the EOR projects depends on pressure, and deeper reservoirs are therefore preferred (Flanders & Shatto, 1993).

Miscible CO_2-EOR

Miscible CO_2-EOR is a multiple contact process, involving the injected CO_2 and the reservoir's residual oil. CO_2 in contact with the residual oil surface would vaporize the lighter oil fractions into the injected CO_2 phase and then the mixture would condense into the reservoir's oil phase. This leads to two reservoir fluids that become miscible (mixing in all parts), with favourable properties of low viscosity, a mobile fluid and low interfacial tension (Figure A3).

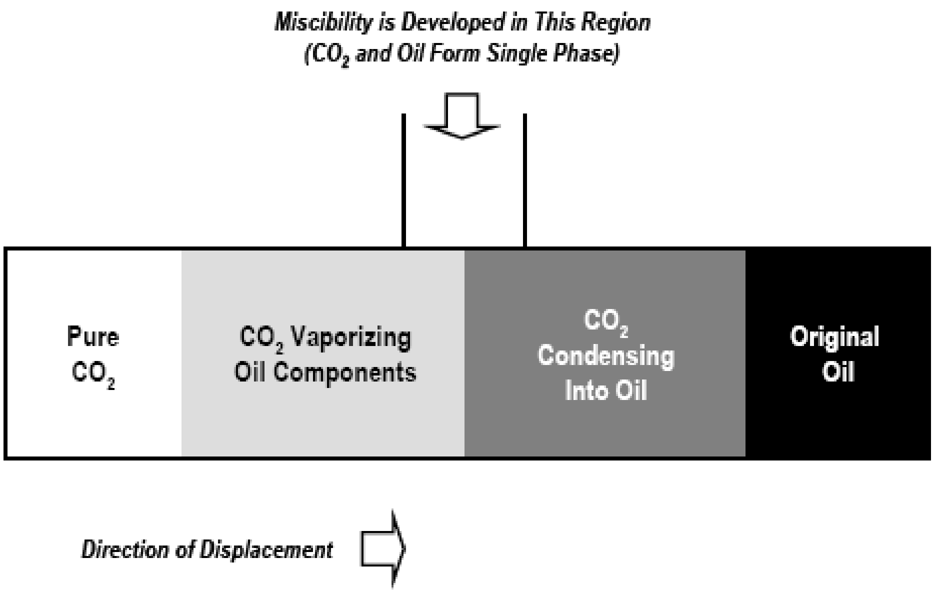

Figure A3. One-dimensional schematic showing the various fluid phases existing in the reservoir and the dynamics of the CO_2 miscible process.

Appendix 1 ***continued***

The primary objective of miscible CO_2-EOR is to remobilize and dramatically reduce the after water-flooding residual oil saturation in the reservoir's pore space.

Immiscible CO_2-EOR

When insufficient reservoir pressure is available or the reservoir's oil composition is heavier (for instance, 13^{o}API and below), the injected CO_2 is immiscible with the reservoir's oil. As such, another oil displacement mechanism called immiscible CO_2 flooding occurs.

The main mechanisms involved in immiscible CO_2 flooding are:

(1) Oil phase swells, as the oil becomes saturated with CO_2;

(2) viscosity reduction of the swollen oil and CO_2 mixture;

(3) extraction of lighter hydrocarbon into the CO_2 phase; and

(4) fluid drive plus pressure.

This combination of mechanisms enables a portion of the reservoir's remaining oil to be mobilized and produced.

In general, immiscible CO_2-EOR is less efficient than miscible CO_2-EOR in recovering the oil remaining in the reservoir. Miscible CO_2 displacement results in approximately 22% higher recovery, whereas immiscible displacement achieves approximately 10% higher recovery (Hadlow, 1992; Beike & Holtz, 1996).

Appendix 1 ***continued***

Residual oil saturation

Residual oil saturation is that portion of the oil that is not displaceable by water, has high variability and depends on the heterogeneity of the depositional system, capillary pressure, wettability, and the connectivity and character of the pore space. Residual oil saturation is a property of the reservoir rock that is strongly affected by rock wettability.

Residual oil saturation is the main target for a CO_2 EOR miscibility project. It would also have an impact on sequestration volumes. If sequestration alone is applied without prior CO_2 EOR miscibility recovery, the residual oil saturation would occupy a portion of the pore volume, decreasing the total volume that can be sequestered.

Geologic Storage

There are however three types of geologic formations that have received most extensive consideration for the geologic storage of CO_2, namely:

- Oil and gas reservoirs
- Deep saline formations
- Unminable coal beds.

In each case, geologic storage of CO_2 is accomplished by injecting it in dense form into a rock formation below the earth's surface. Porous rock formations that hold natural gas, oil or brines or depleted oil and gas reservoirs are potential candidates for CO_2 storage. Suitable storage formations could occur in both onshore and offshore sedimentary basins. Coal beds also might be used for storage of CO_2 if the coal would not later be mined and provided that permeability is sufficient (IPCC, 2005).

The injection of CO_2 in deep geologic formations involves many of the same technologies such as well-drilling and injection technologies that have been developed in the oil and gas exploration and production industry.

CO_2 storage in hydrocarbon reservoirs or deep saline formations is generally would take place at depths below 800 metres, where the ambient pressures and temperatures would usually maintain the CO_2 in a liquid or supercritical state. Under these conditions, the density of CO_2 would range from 50-80% of the density of water and is close to the density of some crude oils. At times, the resulting buoyant forces tend to drive the CO_2 upwards. Consequently, a well-sealed cap rock over the selected storage reservoir is important to ensure that the CO_2 remains trapped underground.

Figure A3 shows the overview of the geologic storage types described above.

Appendix 1 *continued*

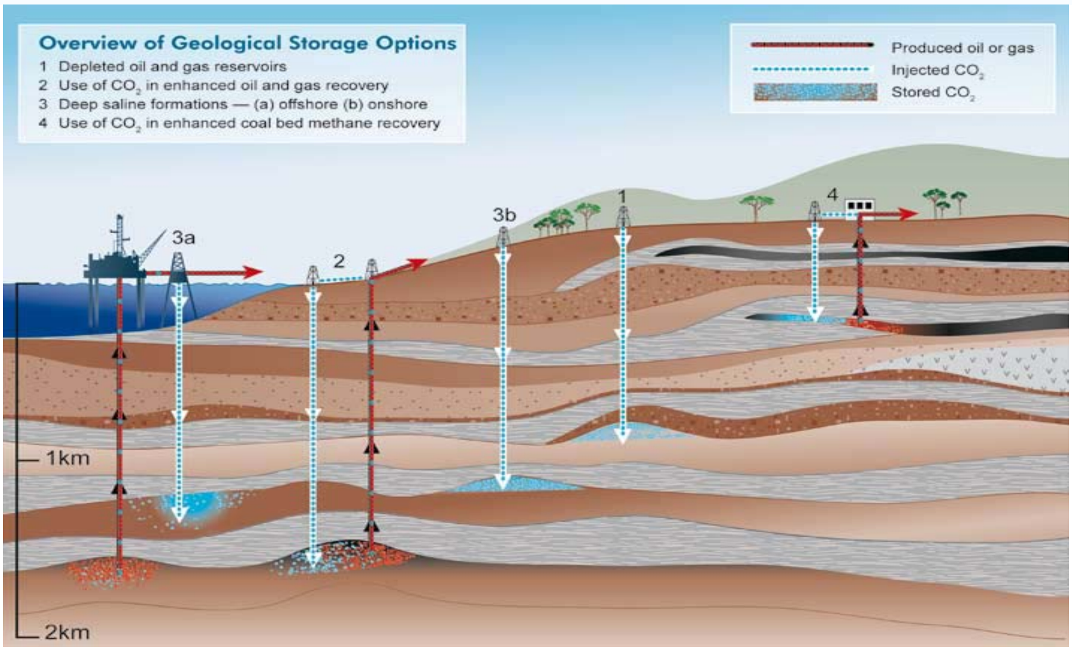

Figure A3. Overview of Geologic Storage Options. (IPCC, 2005)

Once injected into the storage formation, the fraction retained depends on a combination of physical and geochemical trapping mechanisms. Physical trapping to block upward migration of CO_2 is provided by a layer of shale and clay rock above the storage formation. Geochemical trapping occurs as the CO_2 reacts with the in-situ fluids and host rock. First, CO_2 dissolves in the in situ water. Once this occurs, the CO_2-laden water becomes denser and therefore sinks down into the formation. Next, chemical reactions between the dissolved CO_2 and rock minerals form ionic species, so that a fraction of the injected CO_2 would be converted to solid carbonate minerals over millions of years (IPCC, 2005).

Appendix 2. Data used for computing the generation costs of the thermal power plants for Texas Gulf Coast

POWER PLANT	Annual Technical Availability %	Outage Adjust %	Electrical Efficiency (LHV) %	Fixed O&M $/kW/yr	Variable O&M $/kWh	O& M % of Capital Cost	IDC factor %	Medium to Long term Fuel Price $/GJ	Average CO_2 Emission factors Kg/Gj-fuel
Natural Gas Combined-cycle (CCGT)	85	5	47	13	0.0045	6	10	6-7	56
Coal Retrofit (with debt)	90	5	43.5	26	0.003	4	10	2-3	98
Coal Retrofit (no debt)	90	5	43.5	26	0.003	4	5	2-3	98
Conventional Coal	90	2	36	26	0.003	2	12	2-3	93
IGCCs	85	15	47	35	0.015	5	15	2-3	88
Supercritical coal	85	5	44.5	26	0.003	3	12	2-3	91

Data source: Fuel cost, emission factors from US EIA (2007; 2008). Electrical efficiency data from IPCC (2005). Other data from multiple sources and the industry.

Appendix 3 - Power Generation Cost Spreadsheet Static Model

Power Generation Cost Model Sheet 1			Colour Code
			Input variables
Description	**Unit**	**Computation**	**Computed**
			Generation cost
New and location of Plant, Capacity			
Installed / Gross power generation capacity	MW_e	A_e	1
Installed/Gross/Net thermal capacity	MW_{th}	A_{th}	2
Number of hours per year	Hour	**8760**	**Constant** 3
Availability (annual capacity factor)	%	B	4
Outage adjustment factor	%	C	5
Annual full load operation hours	Hours/year	$D_h=8760*(B-C)$	6
Electricity efficiency	%	Eff_e	7
Heat efficiency	%	Eff_h	8
Total electricity generation	MWh/year	$E_e = A_e *D_h$	9
Steam/heat generation	MWh/year	$E_{th} = A_{th} *D_h$	10
Annual fuel consumption	GJ/year	$F=3.6*(E_e+ E_{th}) /0.01(Eff_h+ Eff_e)$	11
Total investment in power plant	$million	$G	12
Specific investment in power plant	$million /MWe	$H=G / A_e$	13
Discount rate	Per annum	r_d	14
Economic life of investment	Years	Yr	15
Capital recovery factor (CRF)	%	$I=\{PMT(r_d, yr,1)*-1\}$	**Computer generated**16
IDC factor r_{idc}	%	$K=1+r_{idc}$	17
Annualised investment (capital) cost	$million	$\$_J =H* I*K$	18
Fixed operation and maintenance (O&M) cost	$million	L	19
Variable O & M (VO&M) cost	$million	M	20
Annual operation and maintenance (O&M)cost	$million /year	$\$_N=(L* A_e+M* E_e)/G$	21
Fuel price	$ / GJ	P	22
Fuel costs per year	$million /year	$\$_Q=P* F$	23
Total annual costs of electricity (and steam) generation	$million /year	$R=\$_Q +\$_N +\$_J$	**24**
Average cost of generated electricity	**USD / MWh**	$\$_S=R/E_e$	**25**
Calculation check:			26
Levelised lifetime cost for generated electricity (€)	$\$_€ = [G – pv (r_d, yr,N+Q)] / pv(r_d, yr, E_e)*10^6$		
Difference between average and levelised cost			$\$_S - \$_€$

Appendix 3 – Power Generation Cost Model spreadsheet I (*Continued*)

Description	Unit	Computation	
Environment – Emissions			
CO_2-emission factor	kg/GJ-fuel	**T**	27
SO_2-emission factor	kg/GJ-fuel	**U**	28
NOx-emission factor	kg/GJ-fuel	**V**	29
Particulate matter emission factor	kg/GJ-fuel	**W**	30
CO_2-emissions	tonnes/year	$X_T = F*T$	31
SO_2-emissions	tonnes/year	$X_U = F*U$	32
NOx-emissions	tonnes/year	$X_V = F*V$	33
Particulate matter (PM) emissions	tonnes/year	$X_W = F*W$	34
Pollutant Limits			
Emission limit for CO_2	tonnes/year	$Б_C$	35
Emission limit for Sulphur oxides	tonnes/year	$Б_s$	36
Emission limit for Nitrogen oxides	tonnes/year	$Б_N$	37
Emission limit for PM	tonnes/year	$Б_{PM}$	38
Penalties			
CO_2 emissions cost per tonne	$/tonne	Y_T	39
SOx emissions cost per tonne	$/tonne	Y_U	40
NOx emissions cost per tonne	$/tonne	Y_V	41
PM emissions cost per tonne	$/tonne	Y_W	42
Net CO_2-emissions	tonnes/year	$X_T – Б_C$	43
Net SO_xemissions	tonnes/year	$X_U - Б_s$	44
Net NOx-emissions	tonnes/year	$X_V - Б_N$	45
Net PM emissions	tonnes/year	$X_W - Б_{PM}$	46
Net CO_2-emissions per MWh	kg/MWh	$X_T – Б_C/E_e$	47
Net SO_x-emissions per MWh	kg/MWh	$X_U - Б_s/E_e$	48
Net NOx-emissions per per MWh	kg/MWh	$X_V - Б_N/E_e$	49
Net PM emissions per MWh	kg/MWh	$X_W - Б_{PM}/E_e$	50
Net CO_2-emission cost per MWh	$/MWh	$Y_T (X_T – Б_C/E_e)$	51
Net SO_x-emission cost per MWh	$/MWh	$Y_U (X_U - Б_s/E_e)$	52
Net NOx-emission cost per per MWh	$/MWh	$Y_V (X_V - Б_N/E_e)$	53
Net PM emission cost per MWh	$/MWh	$Y_W (X_W - Б_{PM}/E_e)$	54
Marketable products to offset cost			
CO_2 captured and delivered at transport/pipeline gate	*tonnes/year*	**A**	55
CO_2 sale per tonne	*$/tonne*	Y_T	56
Potential revenue from CO_2 sales	*$*	Y_T*a	57
profit CO_2 per MWh	*$/MWh*	$Y_T*a/(D*A_e)$	58

Appendix 3 – Power Generation Cost Model spreadsheet I *(continued)*

Description	Unit	Computation	
Marketable products to offset cost			
SOx captured and delivered at transport/pipeline gate	*tonnes/year*	**B**	59
SOx sale per tonne	*$/tonne*	$\mathbf{Y_U}$	60
Potential revenue from SOx sales	*$*	$\mathbf{Y_U*b}$	61
profit SOx per MWh	*$/MWh*	$\mathbf{Y_U*b/(D*A_e)}$	62
Slag/ash produced and delivered at transport gate	*tonnes/year*	**c**	63
Slag/ash sale per tonne	*$/tonne*	$\mathbf{Y_X}$	64
Potential revenue from slag/ash sales	*$*	$\mathbf{Y_X*c}$	65
profit slag/ash per MWh	*$/MWh*	$\mathbf{Y_X*c / (D*A_e)}$	66
Cooling (optional)			
Underline Cooling system (Open loop, Closed loop, dry/air cooled)			
Water (expected) withdrawal factor	Kg/MWh	**Ø**	67
Total water withdrawal	Tonnes/year	$\mathbf{E_e}$ *** Ø**	68
Water consumption factor	Kg/MWh	**Z**	69
Net Water consumption	Tonnes/year	$\mathbf{E_e *Z}$	70
Cost of water per tonne	$/tonne	**Β**	71
Cost of water per MWh	$/MWh	$\mathbf{Z* \beta}$	72
Net Average generation cost to the plant	$/MWh	$\mathbf{\$_S + Z*\beta + Y_T (X_T - Б_C/E_e) + Y_U (X_U - Б_s/E_e) + Y_V (X_V - Б_N/E_e) + Y_W (X_W - Б_{PM}/E_e) - Y_T*a/(D*A_e) - Y_U*b/(D*A_e) + Y_X*c/(D*A_e)}$	
<u>Net levelized generation cost to the plant</u>	$/MWh	$\mathbf{\$_€ + Z*\beta + Y_T (X_T - Б_C/E_e) + Y_U (X_U - Б_s/E_e) + Y_V (X_V - Б_N/E_e) + Y_W (X_W - Б_{PM}/E_e) - Y_T*a/ (D*A_e) - Y_U*b/(D*A_e) + Y_X*c/(D*A_e)}$	

Appendix 3 - Power Generation Cost Model spreadsheet II *(continued)*

Sizing the Carbon Dioxide Capture Plant

Description	Unit	Computation
CO_2-emissions	Tonnes/ year	$X_T = F*T$
Proposed Capture fraction	%	A
CO_2 Captured	Tonnes	$\alpha*X_T$
Electricity required for unit CO_2 capture	kWh /tCO_2	B
Electricity required for CO2 capture	GWh	$\beta * \alpha*X_T$
Heat required for capture per tonne CO_2	GJ/Tco_2	H
total heat required for capture	GJ	$H* \alpha*X_T$
Total annual energy (fuel) of power plant	Gj	D
Fraction of heat in total energy	%	$F_h = H* \alpha*X_T / D$
Equivalent in MW installed/gross capacity used for CO_2 Capture	MW	$F_h * A_e$
Electric required for unit CO_2 compression	kWh /tCO_2	C
Electric required for CO_2 compression	GWh	$C* \alpha*X_T$
Total electricity requirement for capture	GWh	$F= \alpha* X_T(\beta + C)$
Fraction of total electric required for capture		$F_c = F/E_e$
Equivalent in MW installed/gross capacity	MW	$F_c * A_e$
Total installed/gross capacity required for capture	MW	$G= A_e (F_h + F_c)$
Overall electricity generated for capture	MWh/year	$J = G*D_h$
Fraction of installed/gross capacity	%	$F_T = F_h + F_c$
Specific Capital Cost of Capture plant	$/kW	L
Gross capture cost (Capex)	$million	$\$_L = L*G$
Add 10-20% to cover absorber vessel cost	$million	$\$_{LT} = (1.1\text{-}1.2)* \$_L$
Discount rate	Fraction	r_d
Economic life of capture plant	Yr	y_r
Capital Recovery factor	%	$K= \{PMT(r_d, yr,1)*-1\}$
IDC	Fraction	r_{id}
Annualised investment of capture plant	$million	$\$_{Acapex}=L*G *K*(1+r_{id})$
O&M electrical unit (% of power plant O&M)	%	$F_T = F_h + F_c$
O&M electrical unit	$million	$\$_{EOM} = F_T * \$_N$

Appendix 3 - Power Generation Cost Model sheet II *(continued)*

Description	Unit	Computation
Fixed O&M - chemical section (fraction of total investment)	%	F_{com}
Fixed O&M - chemical section	$million	$\$_{com} = F_{com} * \$_L$
Variable O&M		
Amine required per tonne CO_2 captured	Amine/tCO_2	V_{Am}
Amine consumption	Tonne	$V_{Am} * \mathbf{A*X_T}$
Amine price	$/tonne	$\$_{Am}$
Amine cost	$million	$\$_{v1} = \$_{Am} * V_{Am} * \mathbf{A*X_T}$
Alkaline required per tonne CO_2 captured	Alkaline/tCO_2	V_{Al}
Alkaline consumption	Tonne	$V_{Al} * \mathbf{A*X_T}$
Alkaline price	$/tonne	$\$_{Al}$
Alkaline cost	$million	$\$_{v2} = \$_{Al} * V_{Al} * \mathbf{A*X_T}$
Activated charcoal required per tonne CO_2 captured	Act.charc/tCO_2	V_{Ac}
Activated charcoal consumption	Tonne	$V_{Ac} * \mathbf{A*X_T}$
Activated charcoal price	$/tonne	$\$_{Ac}$
Activated charcoal cost	$million	$\$_{v3} = \$_{Ac} * V_{Ac} * \mathbf{A*X_T}$
Any other chemicals combined per tonne CO_2	other/tCO_2	V_{other}
Combined consumption	Tonne	$V_{other} * \mathbf{A*X_T}$
Combined price	$/tonne	$\$_{other}$
Combined cost	$	$\$_{v4} = \$_{other} * V_{other} * \mathbf{A*X_T}$
Total Variable O&M cost	$million	$\$_T = \$_{v1} + \$_{V2} + \$_{v3} + \$_{v4}$
Total Annual Operation & Maintenance cost	$million	$\mathbf{\$_{TAOM}} = \$_{com} + \$_T + \$_{EOM}$
fraction of Fuel cost due to operation of capture plant (fraction of original fuel)	%	F_{com}
Annual Fuel cost due to operation of capture plant	$million	$\$_{AF} = F_{com} * Q$
Total Annual cost of capture	$million	$\$_{TAC} = \$_{AF} + \mathbf{\$_{TAOM}} + \$_{Acapex}$
Cost of Capture per tCO_2	$/$tCO_2$	$\$_{CC} = \$_{TAC} / A * \mathbf{X_T}$
Cost of Energy (COE) for the Capture	**$/MWh**	$\mathbf{\$_{CC} / J}$

Appendix 3 - Power Generation Cost Model sheet II *(continued)*

For Power Plant expanded to cover Power Capacity Requirements for CO_2 Capture

Description	Unit	Computation
Total installed capacity	MW	$C_T = A_e + G$
total generation	GWh	$W = E_e + J$
Total cost of capture and power generation	$million	$\$_{TAC} + R$
Cost of Energy (COE) for the Capture	**$/MWh**	$\mathbf{\$_{TAC} / J}$
Final Average cost of power generation	**$/MWh**	$\mathbf{(\$_{TAC} + R) / W}$
Net CO_2 emissions to the environment (CO_2 not captured)	Tonne/year	$\alpha(1- \mathbf{X_T})$
CO_2 emission per generated MWh electricity	Kg/MWh	$\alpha(1- \mathbf{X_T})/ W$
Additional CO_2 generated during capture process	tonnes/yr	$\mathbf{J} * \alpha(1- \mathbf{X_T})/ W$
Net total CO_2 emissions to the environment	Tonne/year	$\alpha(1- \mathbf{X_T}) + \mathbf{J} * \alpha(1- \mathbf{X_T})/ W$

Appendix 4 – Press Release

Researchers at **Gulf Coast Carbon Center** of the Bureau of Economic Geology (BEG) of the University of Texas at Austin were **instrumental** in securing a contract recently awarded by the **Department of Energy's (DOE) National Energy Technology Laboratory (NETL)** for **carbon sequestration research**. DOE selected **NRG Energy**, one of U.S' largest electric power providers, to **receive up to $167 million of funding to build a post-combustion CO_2 capture demonstration unit** at the company's W.A. Parish power plant southwest of Houston, Texas. **A portion of the CO_2 emissions will be captured and transported to a nearby oil field and injected deep underground for enhanced oil recovery and long-term storage.** The initiative has an estimated budget of $334 million, with both the U.S. Department of Energy and NRG Energy contributing $167 million each. NRG Energy is set to begin constructing the carbon-capture equipment on a portion of the power plant later this 2010 with the initial injection of carbon dioxide steam into the deep subsurface in 2014. As part of the programme, **NRG has subcontracted with the Bureau's Gulf Coast Carbon Center to receive up to $19 million to monitor the CO_2 during and after injection.** " July 2010. Available from http://www.beg.utexas.edu/newsarchive

PUBLISHED PAPERS

Two conference papers published as part of the thesis at the time of submission of this thesis are.

Paper 1 – *Economic modelling of carbon dioxide integrated pipeline network for enhanced oil recovery and geologic sequestration in the Texas Gulf Coast region* (Essandoh-Yeddu & Gulen, 2009).

Paper 2 "*Economic Analysis of an Integrated Anthropogenic Carbon Dioxide Network for Capture and Enhanced Oil Recovery along The Texas Gulf Coast*" (King, C., Essandoh-Yeddu, J., Gulen, G., & Hovorka, S., 2009).