Fischer-Tropsch gas-to-liquids technology: An assessment of the competitive landscape

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ABSTRACT

Global proven and speculative natural gas reserves are enormous. Unfortunately, much of these reserves is economically stranded and as a result, can not be profitably utilized using traditional methods. In another development, crude oil refiners are facing increasing pressures to produce clean fuels. Environmentalists are asking for such clean fuels that will force refiners to make outrageously high refinery-modification investments.

Fischer-Tropsch Gas-to-Liquids (F-T GTL) technology may offer a sustainable solution to these challenges. On one hand, F-T GTL promises to economically monetize stranded natural gas reserves. On the other hand, F-T GTL is capable of producing fuels with qualities that surpass the most stringent current and future clean-fuel requirements.

A competitive landscape is thus formed: gas utilization options on one side; automobile fuel production on the other side; and F-T GTL in the centre. The question is: *how competitive is F-T GTL in this landscape?*

In response, I developed a real-time economic model using (amongst others) the Monte Carlo Method. The model captures the competitive landscape as defined, and compares the viability of competitors in the landscape, using different scenario settings.

In the study I present a ranking of the competing options in the landscape in descending order of viability, based on the relative sizes of their NPVs as estimated for each baseline scenario. Finally, I interpret the rankings.

Based on the outcome of this research, the answer to the question of whether the current interest in F-T GTL will be sustained or not is an emphatic 'yes'.

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SCF	Standard Cubic Feet
BTU/SCF	British Thermal Units/Standard Cubic Feet
MM	Million
MMSCF	Million Standard cubic feet
MSCF	Thousand Standard cubic feet
MMSCFD	Million Standard cubic feet per day
MMBTU	Million British Thermal Units
BCF	Billion cubic feet
TCF	Trillion cubic feet
BCF/D	Billions cubic feet/day
BCF/A	Billion cubic feet/annum
bpd	barrels per day
PJ	Peta Joules
NG	Natural gas
t/d	tons/day
t/a	tons/annum
kt/d	kilotons/day
kt/a	Kilotons/annum
TPA	Tons per annum
MMTPA	Million tons per annum
W	Watts
M	Mega watts
MW-h	Megawatts-hour
GW-h	Giga watts-hour
TW-h	Terawatts-hour
K	Economies of scale constant
Y	Economies of scale index for chemical plants (0.6615)

LIST OF SYMBOLS AND ACRONYMS

LNG:	Liquefied Natural gas
CNG:	Compressed Natural gas
PNG:	Pipelined Natural Gas
GTW:	Gas-to-Wire
GTS:	Gas-to-Solid
DME:	Di-Methyl Ether
MTO:	Methanol-to Olefins
F-T GTL (CCNP):	FT- GTL at **C**urrent **C**APEX, products attract **N**o **P**remium
F-T GTL (CCLP):	FT- GTL at **C**urrent **C**APEX; products attract a **L**ow **P**remium (5%)
F-T GTL (CCHP):	FT- GTL at **C**urrent **C**APEX; products attract a **H**igh **P**remium (20%)
F-T GTL (FCNP):	FT- GTL at **F**uture **C**APEX (this is 35% less than current CAPEX); products attract **N**o **P**remium
F-T GTL (FCLP):	FT- GTL at **F**uture **C**APEX (this is 35% less than current CAPEX); products attract a **L**ow **P**remium (5%)
F-T GTL (FCHP):	FT- GTL at **F**uture **C**APEX (this is 35% less than current CAPEX); products attract a **H**igh **P**remium (20%)
CAPEX:	Capital Expenditure
OPEX	Operating Expenditure
Rev	Revenue from product sale in the nth year
OE	OPEX in the nth year
OPC	Operating cost
MC	Maintenance Cost
OC	Overhead cost
RC	Running Cost
SC	Shipping Cost
FS	Feedstock Cost
CIF	Cost of Insurance and Freight
FOB	Free on board
NPV	Net present value
IRR	Internal rate of return
BTU	British Thermal Units

CHAPTER ONE

1 INTRODUCTION

1.1 Introduction

The global gas reserves are tremendous. They are, conservatively, of the order of 5000 trillion cubic feet (Verghese, 2003; Gass, 2005). The established routes of getting this gas to the market are through the Liquefied Natural Gas (LNG) and Pipelined Natural Gas (PNG) options. Unfortunately more than 60 per cent of these reserves are in locations too far from the market for these two established routes to be profitable (Chang, 2001; *Oilfield Review*, 2003). In other cases, the sizes of the individual reserves are not large enough to justify the enormous capital expenditure required to initiate these two traditional gas utilization options.

In addition, a good proportion of this available gas is associated gas. Associated gas is gas discovered along with crude oil during the exploitation of crude oil wells. The inability of oil companies to route this associated gas to the market, for the reasons given above, has been compelling these companies to flare the gas. This has resulted in colossal environmental pollution (Thackeray, 2000).

The limitations associated with LNG and PNG encouraged developments in the other possible gas utilization options. These options include the Compressed Natural Gas (CNG), Gas-to-Solid (GTS), Gas-to-Wire (GTW), and Gas-to-Liquids (GTL). GTL is generic for Fischer-Tropsch Gas-to-Liquids (F-T GTL), Methanol synthesis, and Di- Methyl Ether (DME) synthesis. Significant technological

improvements have been made with these additional gas utilization options over the years. They are now in the position to compete with the conventional LNG and PNG.

Concurrent with the developments highlighted above are developments in the crude oil sub-sector of the oil and gas industry. Crude oil prices have attained and stayed at alarmingly high levels. Secondly, oil reserves are getting depleted at frightening rates. As a result, many oil-rich countries want to diversify their energy investment. Thirdly, the environmentalists are closing in on crude oil refiners. They are asking refiners to produce fuels free of aromatics and sulphur. The investments required to achieve the feats required by the environmentalists will drive the crude oil refiners out of business (Clarke & Phillips, 2004?).

The refiners have consequently avoided making these investments by refining 'smart'. Smart refining refers to careful selection of crude oil feedstock. They have succeeded in meeting the current specifications by refining smart. However, the future specifications are stringent beyond the capabilities of smart refining. It therefore appears that refiners will imminently be compelled to make the expensive investments (Clarke & Phillips, 2004?).

There is, luckily, a solution. The fuels generated from conventional crude oil can also be gotten from natural gas. This is achievable through the Fischer-Tropsch Gas-to-Liquids synthesis. The fuels from this F-T GTL technology surpass the

most stringent current and future clean-fuel requirements (Clarke & Phillips, 2004?; Culligan, 2005; Clark, Evans, & Virrels, 2002). However, the question of interest to crude oil refiners is whether it is better (and cheaper) to undertake the expensive modifications of their current refineries or to embrace F-T GTL (Clarke & Phillips, 2004?).

The exposition given thus far, illustrates the complex interplay of the issues in the crude oil and natural gas sub-sectors of the oil and gas industry. Obviously, F-T GTL is at the heart of these issues.

1.2 Problem Statement and Substantiation

Fischer-Tropsch Gas-to-Liquids (F-T GTL) processes have enjoyed alternate periods of global interest and disinterest since their first commercial use in Germany during World War II (Waddacor, 2005b). Interests were spurred by rising oil prices and dampened by subsequent drop in oil prices coupled with techno-economic immaturity of the F-T GTL processes. However, the growing availability of massive natural gas reserves, rising oil prices, increasing environmental concerns, and gradual improvements in Fischer-Tropsch and related technologies currently appear to be enhancing the economic prospects of F-T based GTL processes.

The current competitive landscape for F-T GTL technology is multi-faceted. Upstream, F-T GTL (and GTL in general) competes with various other gas

monetization options like Liquefied Natural Gas (LNG), Pipelined Natural Gas (PNG), Compressed Natural Gas (CNG), Gas-to-Solids (GTS), and Gas-to-Wire (GTW). It competes from upstream to downstream with other GTL technologies like Methanol, Ammonia/Urea and Di Methyl Ether (DME) production; and downstream with traditional crude oil refining.

The competition upstream is to allow gas companies and countries to choose the gas utilization option(s) with the best economic returns and (in some cases) the most favourable environmental impacts. The competition downstream, on the other hand, is fuelled by a combination of economic, environmental and quality considerations of the final downstream products. Whether current interest in F-T GTL will be sustained at the global level or not, depends on how the technology fares in the various facets of the competitive landscape.

Up till now, F-T GTL technology has either been compared with gas utilization options (Chang, 2001; Abdul-Rahman & Al-Maslamani, 2004 Subero, 2004; Seddon, 2004;). or with crude oil refining (Al-Saadoon, 2005); but not with both in a single model. This has been attributed to the difference in their target markets. However, techno-economic reasons and environmental concerns now link the competitions upstream and downstream. The decision to adopt an option upstream (or downstream) can no longer be taken in isolation of the realities downstream (or upstream).

A gas company or a gas-rich country would want to evaluate the gas utilization options open to it so as to select the most economically viable. It will however be disastrous for such a company or country to reach its conclusions without considering the events in the oil sub-sector.

As an illustration, let us assume that, after an economic evaluation of the gas monetization options for a specific scenario, a gas company or country discovers that F-T GTL is the most viable option. This outcome is not sufficient to make the company or country commit to investing in an F-T GTL facility. This is because, it is still necessary for such a company or country to evaluate the F-T GTL option against crude oil refining; since the products of F-T GTL and refineries compete in the same market.

If it is discovered that F-T GTL is an inferior investment option to crude oil refining, then it will be unwise to take the F-T GTL gas monetization route. This is despite the fact that, according to our assumption, F-T GTL was discovered to be the most viable gas monetization option. In a case such as this, the investing country or company will be compelled to choose a gas monetization option economically inferior to F-T GTL for reasons outside the gas sub-sector.

This is the kind of interplay that exists upstream (gas monetization options) and downstream (crude oil refining) of the F-T GTL value chain. This is why it is

imperative that any economic evaluation that is done should incorporate all the options downstream and upstream.

It is therefore imperative that a model or models that capture the entire gamut of the competitive landscape in which the F-T GTL technology is placed is developed. Such a model will better serve oil and gas companies and governments in taking investment and legislative decisions for their energy sectors.

1.3 Research Aims and Objectives

1.3.1 Aims

I intend to present at the end of this research a comprehensive model that objectively rates the F-T GTL gas monetization route against all the other options upstream and downstream. This model should be able to provide adequate guidance on the situations where F-T GTL is the most viable option and where it is not.

1.3.2 Objectives

In the course of this research;

I. I shall provide a comprehensive review of the existing literature on the subject matter;

II. I shall develop an economic model;

III. My model shall incorporate both the upstream and downstream competitive scenarios faced by the F-T GTL technology;

IV. I shall employ this model in predicting whether the current interest in F-T GTL technology will be sustained;

V. Oil companies and gas-rich countries should, using my model, be able to adequately take guided investment and legislative decisions for their energy sectors and portfolios.

1.4 Method of Investigation

1.4.1 Analysis of Literature and Sources of Investigation

Literature sources to be used include;

- handbook sources
- technical papers
- journals
- internet and intranet search

The aspects of these sources that will be used will include texts, models and data. These sources shall be studied, compared, analyzed critically and used as guides. The results obtained at the end of this research work shall also be compared with what exists in these chosen literature sources.

1.4.2 Empirical Investigation

A competitive landscape model shall be developed. The model shall be validated. The resulting outcomes shall be compared with the results obtainable

from existing literature. Finally, options for synergies shall be explored and recommended where necessary.

1.5. Thesis Outline

The rest of this thesis shall follow the following structure: in chapter two, I shall be presenting a detailed literature review. In this review, I shall zoom in on each of the sections of the competitive landscape. I shall review the existing literature on each of the gas monetization options as well as the options in the downstream sector of the oil and gas industry. I shall show the strengths and weaknesses of the literature. I shall also justify the need for this research work.

In chapter three, I shall be developing an economic model that captures the realities of the entire competitive landscape. The results obtained from the model shall be presented in chapter four. The concluding chapter shall be chapter five. In chapter five, I shall extract my conclusions from the results gotten from the model. I shall subsequently give recommendations based on my findings.

CHAPTER TWO

2 LITERATURE REVIEW

2.1 Introduction

The attention enjoyed by Fischer-Tropsch Gas-to-Liquids (F-T GTL) technology, as evidenced by the myriads of literature on the subject, is phenomenal. Perhaps this proliferation of literature on the technology should not come as a surprise. All the major oil and gas companies, technology companies in the energy industry, gas-rich countries, and environmentalists are now actively involved with the Fischer-Tropsch technology; one way or the other.

Much of the literature on the Fischer-Tropsch process is by in-house experts from the energy companies, the technology companies, gas-rich countries and the academia. The viability of the technology, as well as other issues relating to the technology, has been the focus of oil and gas conferences in the last decade. That this technology has been enjoying special attention in the global oil and gas circles in recent times is obvious from the nature and sources of literature that I shall be reviewing.

There are five principal factors responsible for the renewed attention that the F-T GTL synthesis is enjoying.

- There is the desire to exploit the existing stranded gas reserves. Stranded (or remote) gas is natural gas existing in fields far from established gas production and transmission infrastructure and markets. The effect of this

distance from established infrastructure and markets is that such gas is expensive to commercialize through traditional monetization options;

- The F-T technology is continually enjoying significant capital cost reduction. This has been increasing its economic viability in recent times;
- There is an increasing demand for cleaner fuels and low-cost chemical feedstock;
- There is a strong pressure for the flaring of associated gas to be discontinued. Associated gas is the natural gas or similar mixture of organic gases found in association with crude oil deposits in an underground geological formation. By extension, non-associated gas is the gas found in 'gas-only' reservoirs; and
- Gas-rich countries want to diversify their gas investments.

Most of the research interest in the F-T synthesis to date has been for the purpose of ascertaining the economic viability of the technology. It is necessary to establish the economic viability or otherwise of this technology for several reasons. The capital requirement for a single F-T GTL facility is gigantic. It is typically in the order of several billion of dollars for stand-alone F-T GTL plants.

Secondly, the technology has to compete with other gas monetization technologies. Gas monetization is simply the economic utilization of gas in gas reserves. Some of these gas monetization technologies, such as Liquefied Natural Gas (LNG), are already established. Others, like Compressed Natural

Gas (CNG), are emerging. It is therefore imperative for a prospective investing country or company to be sure that their planned investment in the F-T GTL process is a wise move.

The emerging F-T GTL technology finds itself in an industry where several other gas monetization options are already established. For it to capture any considerable share of the gas market, it must compete favourably with these established options as well as with other emerging technologies. It is pertinent to state here that F-T GTL competes simultaneously in several parts of the oil and gas industry.

It competes, upstream, with other gas monetization options like the LNG, CNG, Pipelined Natural Gas (PNG), Gas-to-Wire (GTW), and Gas-to-Solid (GTS). The products of F-T GTL also compete, downstream, with the products of conventional crude oil refining. The competition downstream with refinery products is as a result of the fact that diesel is a major F-T GTL product.

Di-Methyl Ether (DME), methanol and Methanol-to-Olefins (MTO) are other downstream products that compete with those of F-T GTL. The interesting thing is that DME, MTO, and methanol are derived from processes similar to the Fischer-Tropsch process. They are gas monetization options as well. They therefore compete with F-T GTL both upstream and downstream.

Experts have attempted to ascertain the viability of the F-T GTL technology vis-à-vis other competing options. I hereby present a review of the results of the efforts of these experts as reported in published and other available literature sources.

2.2 Natural Gas Reserves

There are no exact figures for the global natural gas (NG) reserves. However, many authors seem to agree on values around or over 5000 trillion cubic feet (TCF). As of January 1988, the ascertained and economically accessible reserves of NG amounted worldwide to over 144,000 billion cubic meters [5083 TCF], corresponding to 124 billion tons of oil equivalents (Parmaliana et al., 1998)

Verghese (2003) asserts that there has been a phenomenal growth in gas reserves within the last 20 years. Proven gas reserves doubled to figures over 5000 TCF. He holds that a significant proportion of the additional reserves is stranded. Apanel (2005) gives the value of stranded gas at about 3000 TCF. Chang (2001), quoting *Oil and Gas Journal,* agrees that the discovered global gas reserves exceed 5000 TCF and that over half of this is stranded.

However, Chang (2001) supplies another estimate from *Enron* which puts the value of stranded natural gas at 9000 TCF. He speculates that over 4500 TCF of this stranded gas is offshore. The US Energy Information and Administration (EIA) put its estimates for the global proven reserves at 5500-6000 TCF. This

quantity is claimed to be enough to meet the global demand well into the second half of the twenty-first century, based on current consumption levels. It is believed that at least four times that amount remains to be found and produced (Gass, 2005). Gass' statement is suspect considering that it estimates the size of yet-to-be-found gas reserves.

Jacobs (2005) predicts that the global resources of conventional natural gas represent 70-100 years of current consumption. Chew (2003), on his part, speculates that the global gas resource is 11,750 TCF and that this is equivalent to 124 years' supply at 2001 levels of production. Chew seems rather optimistic here.

According to the Autumn 2003 issue of the *Oil Review*, the world's proven gas reserves are estimated at an average of 5500 trillion cubic feet (TCF) [156 trillion m^3]. Factoring in potential reserves brings the total to about 13,000 TCF [372 trillion m^3]. Adding reserves from unconventional sources, like *coalbed* methane, and highly speculative sources like naturally occurring gas hydrates, gives a grand total of about 700,000 TCF [20,000 trillion m^3].

Proven gas reserves increased continuously over the last 3 decades from about 40 trillion cubic meters [1420 TCF] in 1970 to 177.6 trillion cubic meters [6270 TCF] at the start of 2002 (Cornot-Gandolphe et al., 2003). These authors hold that their latest estimate represents sixty years of current (2003) production rate.

While gas consumption increased by a factor of 2.3 between 1970 and 2002, proven gas reserves increased by a factor of 3.5.

Apanel (2005) writes that the world natural gas reserves have been growing at a faster rate than proven oil reserves. He reports that these gas reserves currently represent over 85% of the energy equivalence of proven oil reserves, of which about 75% (of oil reserves) is considered to be the less desirable heavy crude oil.

Oilfield Review (2003) reports that of the proven and potential conventional gas reserves, up to 80% are too far from large markets to be transported by pipeline. Examples are the large gas reserves in Qatar, Iran, the United Arab Emirates, Russia, Saudi Arabia, Canada and Alaska, USA, that await development of new transport technology to bring their reserves to the market.

The pressure to bring stranded gas to the market is mounting (Verghese, 2003). Verghese gives reasons for this. Energy demand, driven by economic growth, is expected to rise by over 50% in the next two decades. Secondly, the global demand for clean energy (natural gas and renewable sources) is anticipated to grow faster than the overall demand for fossil fuels.

Verghese claims that not only has natural gas been winning market share from coal, but that the former is currently overtaking coal in worldwide usage. He states further that gas now accounts for 25% of the primary energy consumption.

He posits that the delivery of gas to markets will rely on a variety of technologies and transportation options. The optimum mode of gas/energy delivery to the market, according to Verghese, will be determined by volume, distance to market, cost of wellhead gas production, as well as geographical and environmental constraints.

Lucas-Clements' (2005) estimates of discovered worldwide gas is 9,725 TCF. He puts worldwide cumulative production at 2,910 TCF and the percentage depletion at 29.9%. He provides estimates of percentage cumulative depletion of gas reserves by region. North America has produced 82.5% of its less than 1,500 TCF gas reserves. This is the highest depletion-reserves ratio. The Middle East has only produced 7.45% of its 3000 TCF reserves. This is the lowest regional depletion-reserves proportion.

The Middle East and the Former Soviet Union jointly account for more than two-thirds of global gas reserves (Cornot-Gandolphe et al., 2003). On a country-by-country basis, Russia ranks first with 30% of worldwide reserves, and Iran second with 16%. Despite this, these authors claim that gas reserves are more widely distributed among regions than oil reserves are.

Finally, the latest BP estimates for 2005 (released in June 2006) put the proven global reserves at 179.83 trillion cubic meters [about 6350 TCF]. The percentage distribution of the reserves is: Middle East, 40%; Europe and Eurasia, 35.6%;

Asia pacific, 8.3%; Africa, 8.0%; North America, 4.1%; and South and Central America, 3.9%.

2.3 Options in the Competitive Landscape

The competitive landscape to be adopted in this research work shall be defined as presented in the figure below.

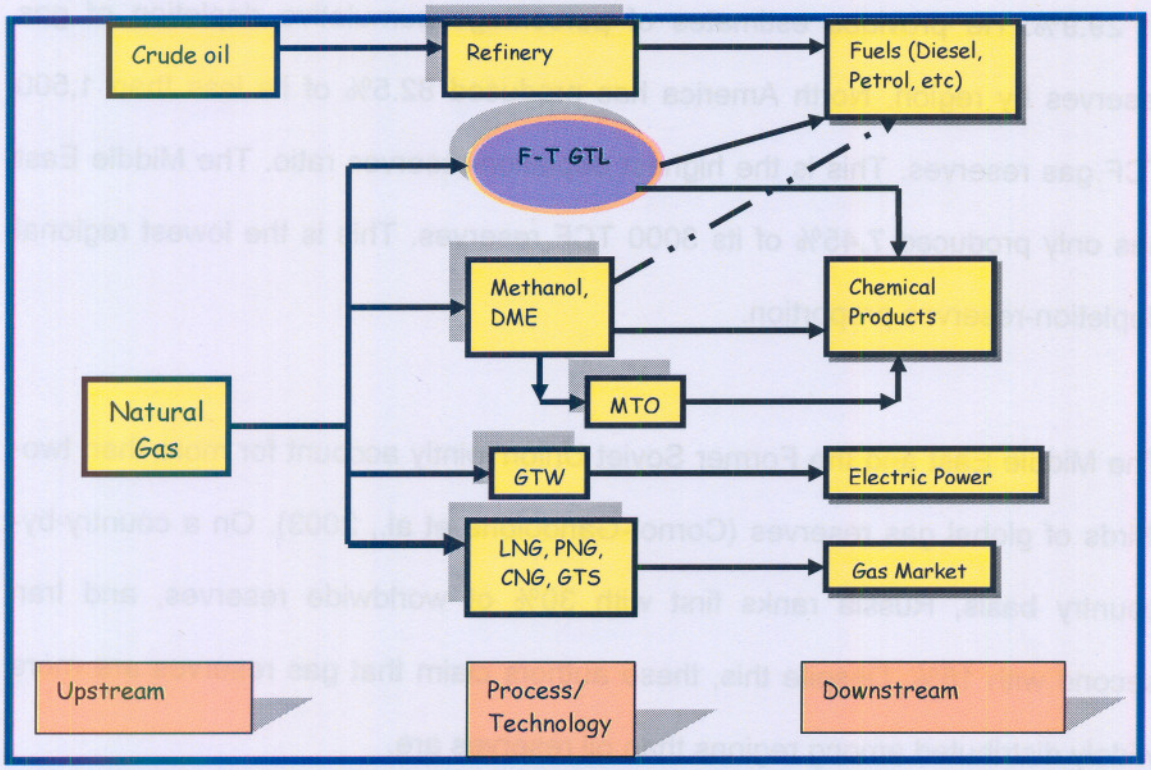

Figure 2.1 The competitive Landscape

2.3.1 Gas Monetization Options

2.3.1.1 Liquefied Natural Gas (LNG)

Liquefied Natural Gas (LNG) is natural gas that has been cooled to the point that it condenses to a liquid. This occurs at a temperature of approximately -161 ^{o}C

and at atmospheric pressure. Liquefaction reduces the gas volume by approximately 600 times. This makes it more economical to transport gas between continents in specially designed ocean vessels.

LNG is unlike the traditional pipeline transportation systems, which is less economically attractive and could be technically or politically infeasible in many situations. Thus, the LNG technology makes natural gas available throughout the world (*University of Houston Institute for Energy Law and Enterprise*, 2003; Coyle, Durr & Shah, 2003; Holditch, 2001; Chang, 2001; & Subero, Sun, Deshpande, McLaughlin, & Economides, 2004).

LNG is a proven gas monetization option that has grown over 30 years from a 3 MMTPA (million tons per annum) industry in the early 1970s to a 106 MMTPA industry in 2001 (Coyle et al., 2003). Despite this, LNG today accounts for only about 6% of the natural gas consumed worldwide, but accounts for some 25% of internationally traded gas.

One of the claims made by Coyle et al. (2003) is that the growth in the LNG market will remain strong in the coming decade. They concede, however, that the ability of the LNG option to continue to compete with existing and emerging gas monetization options will depend on the industry's success in reducing cost throughout the LNG value chain and maintaining exceptional safety, reliability, and environmental performance. They review the different components of the

LNG value chain from gas field to the eventual consumer with emphasis on liquefaction plant and re-gasification terminal.

The market drivers for LNG are the growing worldwide gas demand, abundant gas reserves, and the cost reduction for LNG (Ehrhard, 2005). The principal components of the LNG value chain are:

- Upstream activities
- Liquefaction
- Transportation
- Re-gasification, and
- Marketing

According to the *University of Houston Institute for Energy Law and Enterprise*, the major stages of the LNG value chain, excluding pipeline operations between the stages, consist of the following.

- *Exploration* to find natural gas in the earth's crust and production of the gas for delivery to gas users. Most of the time natural gas is discovered during the search for oil (this is called associated gas).
- *Liquefaction* to convert natural gas into a liquid state so that it can be transported in ships.
- *Shipping* the LNG in special purpose vessels.
- *Storage and Regasification*, to convert the LNG stored in specially made storage tanks, from the liquefied phase to the gaseous phase, ready to be moved to the final destination through the natural gas pipeline system.

The various issues considered at each stage of this value chain, as given by Ehrhard, may be tabulated thus:

Value chain	Considerations
Upstream	Sufficient reserves base, Development and operating costs, Added revenue from liquids
Liquefaction	Competitive cost, Reliability Designed to market Btu Spec
Transportation	Continued cost reductions, Vessels size vs. port availability, Boil-off issues, Ownership vs. time charter
Re-gasification	Terminal location, Onshore vs. offshore, Permitting issues, Costs, berthing, construction timing
Marketing	Market strategy, Pricing indices, Price volume risk management
Commercial	Fiscal terms, Partner alignment, Project financing

Table 2.1 *The LNG value chain*

Ehrhard's (2005) quotes for the investment required over the LNG value chain are as follows:

- Upstream: $500 million - $1 billion
- Liquefaction: $2-3 billion
- Transportation: $150- $200 million/ship
- Re-gasification: $600- $700 million

It should be noted that Ehrhard did not provide the production rate that his figures apply to. The fact that he gave range of costs instead of fixed costs might be to accommodate different production rates. His figures should, as a result, be treated with caution.

LNG trade in 2004 was approximately 131 million tones per annum (MMTPA) and is expected to increase by about 50% to more than 190 MMTPA in 2010 (Barclay & Denton, 2005). They report that as of October 2005, there were a total

of 19 liquefaction facilities in operation with a total of 69 trains, and combined production capacity of more than 150 MTPA.

Barclay (2005), reports that there are two separate LNG markets –Atlantic and Asia Pacific. He claims that the market grows at about 6% per year and that the 2004 total market was 140 MMTPA. His figures for the number of liquefaction plants and trains agree with the ones provided by Barclay and Denton. He, however, adds that the 19 liquefaction plants are spread over 12 countries, while the 46 receiving terminals are in 14 countries.

There are approximately 200 vessels serving the industry, with an expected annual capacity of 25,168,616 m^3 by 2006. Coyle et al., (2003) assert that the engineering of LNG liquefaction and re-gasification facilities is considered a mature technology.

2.3.1.2 Pipelined Natural Gas (PNG)

Natural gas may be transported in an underground, above ground, or sub-sea system of large-diameter pipes. So far, pipeline flows between countries or continents have largely dominated the international gas trade (Cornot-Gandolphe et al., 2003). Pipeline transportation of gas still remains a significant mechanism for gas delivery to the markets. It is recognized that 22% of gas produced crosses an international boundary. Much of this is made possible by the dramatic growth in regional pipeline systems (Verghese, 2003)

Cornot-Gandolphe et al. (2003) hold that capital charges for PNG typically make up at least 90% of the cost of transmission pipelines. The key determinants of pipeline construction costs are diameter, operating pressures, distance and terrain. Other factors, including climate, labour costs, the degree of competition among contracting companies, safety regulations, population density and rights of way, may cause construction costs to vary significantly from one region to another.

Subero et al. (2004) report that compressor stations are positioned along the pipeline's path to keep the gas transportation efficiency. Offshore, operational problems such as the formation of gas condensates and hydrate deposition often occur. These non-gaseous phase events may partially or totally block gas flow through the pipelines. These authors however, conclude that PNG is a tried and true technology and the one with the best known, at least technically, constraints.

Cornot-Gandolphe et al., (2003) expose that pipeline operating costs vary mainly according to the number of compressor stations, which require significant amounts of fuel, and local economic conditions, especially labour costs. In designing a pipeline, the optimal mix of diameter and compression capacity will depend on the expected load factor. Once a pipeline is built, the average cost per unit of throughput will depend almost entirely on the average rate of capacity

utilization. A high level of utilization with a high load factor is usually critical to the economic viability of the pipeline.

According to their report, the investment required to lay a long distance, large diameter line (46 to 60 inches), enabling a throughput of about 15-30 billion m^3/year, currently amounts to $1 billion to $1.5 billion/1000 km. Large-diameter and long distance pipelines imply very high capital investment. They require both large, high-value markets and substantial proven reserves to be economically viable.

They also report that developments over the past decade in offshore pipeline technology have contributed to lower unit costs and have made possible deep-water projects that were previously impossible. One major breakthrough in pipe-laying is the development of a technology capable of laying pipes at 650 metres depth.

Verghese (2003) reports that in the two-year period 1998-2000, almost 55,000 km of new gas lines were laid, connecting major gas resources to target markets. The technology for pipeline systems is evolving both with respect to pipeline material/grade, installation techniques and the functional sophistication of the SCADA (Supervisory Control And Data Acquisition), surveillance, and automation systems being applied to long distance trunk lines. He concludes that this cumulatively has the impact of delivering stranded gas to potential markets

with an acceptable rate of return on the investment, yet ensuring an equitable price for the gas at the wellhead.

The offshore gas is transported to onshore markets by constructed pipelines. Chang (2001) holds that this option requires a lot of capital cost and huge proven gas reserves. Thus, in many situations, this technology is not available. Also, in offshore areas, many critical operational problems might occur in pipelines compared to onshore pipelines such as gas condensate occurrence and hydrate deposition blocking the gas flow.

2.3.1.3 Compressed Natural Gas (CNG)

Compressed Natural Gas (CNG) as a mode of transport of natural gas is now pursued with renewed interests. Earlier attempts in the 1960s to commercialize the technology were met with technical difficulties. This, along with the requirement of heavy investments, rendered the application of the technology commercially infeasible (Subero et al., 2004; Verghese, 2001; Chang, 2001; and Dunlop & White, 2003).

However, recently, the commercial CNG carrier is on the implementation stage. The discovery and development by *Cran & Stenning* of a new type of pressure containment vessel, called a *Coselle,* promises to make CNG transportation attractive (Chang 2001). The gas is pressured up to 3000 psi (20684 kPa) at ambient temperatures in the vessel.

Another approach to CNG is espoused by Enersea Transport. They developed the VOTRANS (Volume Optimized Transportation and Storage) concept in which the natural gas is compressed and cooled to lower temperatures. This reduces the volume of the compressed gas compared to just compressing it at ambient temperatures. At the lower temperatures of 0 to –40°F the process works at lower pressures than at ambient temperatures.

For the "VOTRANS" concept, the ships carry the chilled compressed gas in a boxlike structure, called the "CNG module". The gas is unloaded using a fluid displacement mechanism. The displacing fluid is a mixture of ethylene glycol and water. Both Cran & Stenning and EnerSea have obtained "class approval in principal" from the American Bureau of Shipping for their concepts. This approval allows them to commence commercial deployment of their technologies to the industry. CNG, as a form of gas transport, can apply to stranded gas projects with production rates ranging from 150 to 700 MMScfd and over distances of 3,000 km (Verghese, 2003; Dunlop & White, 2003).

2.3.1.4 Gas-to-Wire (GTW)

Gas-to-wire simply means the conversion of natural gas to electricity. While nuclear engineers are still looking for ways to bring down costs of their technology, another energy converter can come close to the "too cheap to meter" category: the gas turbine (Langston, 2005).

Langston reports that most of the world's newest electricity plants are powered by gas turbine; with natural gas as a fuel. Simple-cycle plants, so called because they use only gas turbines to drive electrical generators, are more efficient (with thermal efficiencies as high as 42 %) than nuclear plants and can cost one-tenth of a nuclear plant per kilowatt output. Combined-cycle plants, which incorporate both gas turbines and steam turbines, also cost much less per kilowatt than nuclear plants, and their thermal efficiencies (as high as 60 percent) have made them the efficiency superstars of the power plant world (Langston, 2005).

Gas-to-wire uses local generation of DC current, transmitting the power over long distances and converting it locally for AC use. Thus, natural gas may be converted into electrical power at an offshore platform and transmitted to shore using high voltage sub sea cables. This involves either linking to a national grid or supplying directly to high-energy industrial consumers (Chang, 2001; Mc Neillie, 2001; Verghese, 2003; Langston, 2005).

The success of these studies will be most beneficial to regions where efforts to develop LNG, CNG or PNG accepting facilities are likely to encounter difficult regulatory and environmental hurdles (Subero et al., 2004; Chang, 2001). This give credence to Verghese's (2003) claim that gas-to-wire projects (under which remotely located gas is used to generate electricity in the form of high voltage direct-current for long distance transmission to the market) is increasingly being

proposed as a viable alternative to LNG. Mc Neillie (2001) of BP confirms that gas-to-wire is a realistic alternative to gas pipelines for the bulk transport of energy.

Developments in AC to DC conversion equipment technology are radically altering the economics, with proponents suggesting that gas-to-wire projects transmitting the equivalent of 1,000 MMSCFD gas can be made to be economically attractive over a distance of 3,000 km (Verghese, 2003).

If the end user of energy requires electricity, for a range of gas to market distances greater than about 1500 km, it is usually more economical to pipeline the gas to the market, and then convert the gas into power. However, transmission systems utilizing DC power systems are developing at quite a pace and offer the potential for economically transmitting electricity for distances greater than about 1500 km (Mc Neillie, 2001).

2.3.1.5 Gas-to-Solid (GTS)

Gas-to-Solid is sometimes called natural gas hydrate (NGH). Chang (2001) defines gas hydrates as ice-like solids formed by the physical combination of water and gas molecules. The natural gas molecules are trapped in the cavities of the ice-like crystalline molecular structure. In their definition, Subero et al. (2004) see natural gas hydrates (NGH) as crystalline solids composed of water and natural gas in physical combination where individual gas molecules exist

within cages of water molecules. Fitzgerald and Taylor (2001) give much the same definition.

Hydrates form naturally in sub-sea as hydrate deposits and the amount is huge. Theoretically, 180 m^3 of methane gas can be concentrated in 1 m^3 of water (Chang 2001). For decades, researchers have been looking for ways to gather these crystals from their deep-ocean deposits and reap what they expect could be a natural gas harvest (Wolman, 2003). Currently, the hydrate is cumbersome because it blocks pipelines and thus a number of researches were concentrated on avoiding hydrate formation.

Kanda and Nakajima, according to Wolman (2003), are taking an opposite approach. Rather than extracting methane (natural gas) from hydrates, they want to turn methane into hydrates. This essentially involves transforming the colourless and odourless gas into small pellets that can be easily stored, transported, and eventually turned back into natural gas (Wolman, 2003).

Preliminary research suggests that dry solid gas could be stored and shipped at sub-zero Celsius temperatures without problems of freezing free water (Subero et al., 2004; Chang, 2001; Verghese, 2003; Wolman, 2003; Fitzgerald & Taylor, 2001; and Kanda, 2006). This is how the name Gas-to-Solid was derived.

Potentially, the product could be stored at stable conditions, for several months, with insignificant gas losses. Depending on the exact composition of the hydrate, the dry product is stable, at atmospheric pressure, at around -40°C. Subero et al. (2004) claim that shipping consultants confirmed to them that the dry hydrate could be shipped at these temperatures using standard ships with additional insulation.

Fitzgerald and Taylor (2001) report that the initial focus of the Hydrate Technology programme was on bulk gas transportation; with the technology being deployed for either floating offshore or coastal onshore facilities. Considerable work was undertaken including:

- Extensive laboratory testing enabling reactor design and process model validation
- Construction and testing of 1 tonne/day pilot plant
- Development and application of dewatering techniques
- Long term hydrate storage at stable conditions and controlled regeneration of gas from storage
- Techno-economic studies
- Shipping studies

The decision was then taken to target stranded associated gas as entry into the gas transportation market and development switched to investigating a lower cost slurry process for smaller gas volumes. This report is consistent with Verghese's (2003) claims.

Nearly 95 percent of the known gas fields in the world are too small to justify the costs required to pipe the gas to a plant, turn it into a liquid, and then transport it on specially equipped tankers (as you have with LNG and CNG). This is one of the factors that are encouraging interest in the development of the GTS technology. However, because hydrates are still a mysterious substance, there are many scientific and engineering obstacles that could make the process cost prohibitive (Wolman, 2003).

The Naval Architect (2003) reports that NGH is expected to be especially interesting for smaller gas fields where the huge start-up costs are not practical. It reports further that only some 30 fields are currently in production worldwide, with a further 970 undeveloped. It also claims that the unit transport costs of NGH are higher than for an LNG tanker although the transport temperature of the former is much more modest (around -15°C to -20°C) and the pressure is atmospheric. *The Naval Architect* claims that NGH costs are higher since the volume of gas for each unit volume of cargo hold is much less than with an LNG.

Kanda (2006) agrees with the shipping cost comparison given by *The Naval Architect.* Notwithstanding, Kanda points out that the initial cost of GTS transport (as a whole) is lower than the LNG transport chain of the same scale by 23-27%. His reasons for these include:

- Elemental equipments of NGH (GTS) production plant are composed of general merchandized products and can relatively easily be procured although they are for high pressure use. Meanwhile, LNG production plant needs special compressors and heat exchangers suitable for cryogenic temperature.
- Although the medium volume of NGH is about 3-4 times the volume of LNG for the same amount of gas, the storage temperature of NGH is -20° C, closer to room temperature than -162° C of LNG and therefore the storage cost of NGH especially at unloading terminal is much lower.

In addition, Kanda asserts that the overall CAPEX of GTS is significantly less than that of the LNG. He presents the results of a specific comparison of NGH chain with LNG chain in two cases. He claims that the results have proven the advantage of the NGH chain in terms of cost by 18-25% in the case of the transport of 0.4 MTPA (1,500 nautical miles)-1MTPA (3,500 nautical miles).

2.3.2 Conventional Crude Oil Refining

Once discovered, drilled and brought to the earth's surface, crude oil is transported to a refinery by pipeline, ship or both. At the refinery, it is treated and converted into consumer and industrial products. Three major refinery processes change crude oil into finished products:

- *Separation:* The oil is separated into its constituents by distillation.

- *Conversion:* The various hydrocarbons produced are then chemically altered to make them more suitable for their intended purpose.
- *Purification*: This is essentially a process of sulphur removal.

In general, refining has been significantly less profitable than other industry segments during the 1990s. Gross refinery margins (the difference between the cost of the input and the price of the output) have been squeezed at the same time that operating costs and the need for additional investment to meet environmental mandates has grown, thus reducing the net margin even further (*Apache Corporation, 2006*).

In addition, much of the investment made during the 1980's was designed to take advantage of the differential between the dwindling supply of higher quality crude oils and the growing supply of heavier and higher sulphur crude oils. When that differential narrowed, however, the financial return on those investments declined. Refining margins peaked in the late 1980's.

Holditch (2001), after comparing the current global oil production rate, the projected production rate, the global oil reserves, and the projected world population; concludes that in the next 20 years, oil production from conventional reservoirs may begin to decline, creating a gap between supply and demand. Young's (2003) forecast of the year for the oil production to attain its peak, agrees with Holditch's. Miró (2006) was more cautious. He holds that it is not

possible to know exactly the date of world oil production's peak, but that almost all of the current most reliable estimates put it between 2004 and 2010.

Watson and Vandervell (2006), in a sharp contrast to these previous authors, argue that conventional crude oil resources are not in imminent danger of running out. They claim that there are sufficient global reserves to last for at least another 40-100 years, when allowing for the potential of technology to extend recoverable oil reserves and 'yet to find' oil. They argue further that there is the potential to recover unconventional reserves, such as heavy oils and tar sands.

Quoting the IEA, Watson and Vandervell assert that global production of crude oil will not peak before 2030, if the necessary investment is made in exploration and production. They report that the IEA forecasts that the global demand for energy will increase by around 50% by 2030 and that oil will remain the largest single source of primary energy, supplying over one third of global energy demand in 2030. Meanwhile, the IEA estimates that meeting its predicted demand for 2030 will require around $3 trillion of global investment in finding, producing, transporting and refining the oil required.

Watson and Vandervell (2006) however concede that, financial returns in refining over the past three decades have generally been very poor. They admit that the return on capital employed was as low as 4.8% between 2000 and 2004 in the UK. This low return on UK refining, according to Watson and Vandervell, has

made it unattractive to invest in new plants. This position agrees with Apache Corporation's claims, reported above.

Refiners in the EU were mandated to modify their processes so that their products could meet certain specifications. 2005 was set as a deadline for certain degrees of compliance. The cut-off time for more stringent compliance was set farther away. Clarke and Phillips (2004?) report that refiners in the EU were innovative in modifying their operations to meet the 2005 specifications for clean fuels. The refiners did this with little or no investment. They applied one or more of the following (called smart refining) in delaying or avoiding this investment altogether.

- Careful crude selection
- Hydrogen management and optimization
- End point management (cut backs)
- Intermediate and final product swaps
- Innovative blending, and
- Moderate and appropriate revamps.

Clarke and Phillips (2004?) expose that the stringent clean fuel 2005 specification in the EU did not create the market for Fischer-Tropsch-based applications as originally expected. Meanwhile, Pirog (2004) estimates that producing complying diesel fuel from crude oil at U.S. refineries requires total investments at those refineries in the range $4 to $13 billion. This investment is for the purpose of meeting mandated on-road diesel requirements. The question

of interest here is whether refiners in the EU can meet future specifications by smart refining, without significant investment.

2.3.3 Gas-to-Liquids (GTL) Technologies

Growing interest is centring on the technology for manufacturing liquid fuel from natural gas and using it as a measure of transporting natural gas and/or utilizing it as a non-petroleum alternative fuel (Morita, 2001). Subero et al. (2004), Morita (2001), and Verghese (2003) see the Gas-to-Liquids technology as primarily consisting of two stages: converting natural gas to synthesis gas in the first step; and then manufacturing liquid fuel from synthesis gas using Fischer-Tropsch process (or similar processes) in the second step.

Most authors however, prefer to see the GTL process as a three-stage process. These stages are:

- Synthesis gas generation
- Fischer-Tropsch/Methanol/ DME syntheses.
- Product workup

(Thackeray, 2000; Holditch, 2001; Jacometti, 2001; Ahmad, Zughaid & El Arafi, 2002; Clarke & Ghaemmaghami, 2003; Abdul-Rahman & Al-Maslamani, 2004; Smith, 2004; Al-Saadoon, 2005; Apanel, 2005; Brook, 2005; Culligan, 2005; Fiato & Sibal, 2005; Jacobs, 2005; and Patel, 2005)

Liquid fuels such as Fischer-Tropsch synthetic fuels, methanol, Di-Methyl Ether (DME), etc. manufactured by this technology are collectively called Gas-to-Liquids (GTL) (Morita, 2001).

2.3.3.1 **Methanol**

One of the GTL routes is to produce methanol from synthesis gas. The synthesis gas is passed through a converter which produces the methanol (Seddon, 2004). Methanol is at the heart of all gas-to-chemicals technologies. Demand for it is currently established as chemical feedstock for manufacturing chemicals such as formaldehyde, acetic acid, and MTBE (Fleisch, 2003). Sadly, the market for chemical methanol is limited (Morita, 2001; Seddon, 2004).

A methanol plant would require about 32 PJ/a of gas to produce 2,500t/d of chemical methanol (Seddon, 2004). Seddon holds that the average trade price for chemical methanol is about $150/t. On a typical world-scale plant this can be produced with gas priced at about $1/GJ. Seddon also reports that process licensors now claim that larger plants can show significant economies of scale for plants producing 5000t/d or more. If these claims are justified, chemical methanol could be produced from gas at values up to $2.5/GJ.

While shedding light on the economics of the methanol route for gas monetization, Seddon asserts that fuel methanol (this is different from chemical methanol with respect to intended markets) could be produced offshore at about

$130/t. According to him, for a much larger operation, methanol could be produced below $100/t .This is equivalent to gasoline at about $26/bbl.

Morita (2001) writes that there have been many attempts to develop a role for methanol in the general fuel market. However, the use of methanol in vehicles is opposed by the vehicle manufacturers and its uptake into the gasoline market seems unlikely (Seddon, 2004). This could be, as Morita reports, because of the low heating value of methanol. The result of this low heating value is a poor fuel economy rate per km-run of the automobile.

2.3.3.2 Di-Methyl Ether (DME)

Interest in Di methyl ether (DME) is spurred by speculations that it has a future possibility as the cleanest diesel, as well as the fuel with the best thermal efficiencies among all GTL fuels (Washimi, 2005). DME is an ether, gaseous, and with an ethereal odour. It is colourless and water soluble. It is a clean-burning alternative to Liquefied petroleum gas (LPG), diesel, LNG, and gasoline. It can be made from natural gas, coal, or biomass. Its properties are extremely close to those of LPG, making it possible for DME to utilize LPG infrastructure (*JFE Holdings Inc, 2006*).

DME can serve as a synthetic fuel that is to diesel what LPG is to gasoline (Morita, 2001). It is gaseous at ambient conditions but can be liquefied at moderate pressures. With a high cetane number, DME has very attractive

characteristics as an alternative fuel for diesel engines. DME can be blended with LPG in a 15 to 20% blend without any modifications to equipment; or it could be used as a replacement. Its low emissions make it relatively environmentally friendly (*Green car congress*, 2006). DME, however, is not suitable for LPG-powered automobiles because of its low octane number (Morita, 2001).

DME production begins by using natural gas, coal or other raw materials to produce synthesis gas. It is produced from this synthesis gas in one of two ways:

- Methanol dehydration (indirect synthesis): This is a process of producing DME from a dehydration reaction, with methanol produced from the synthesis gas.
- Direct synthesis: This produces DME directly from synthesis gas. This process is still in the demonstration stage (Thackeray, 2000; Seddon, 2004).

Seddon (2004) draws attention to a crucial implication of DME possessing properties similar to those of LPG. This, he says, means that DME transport and storage costs will be more than those for methanol. The costs statistics he provides look like this: Gas at $1/GJ will produce DME at about $210/t. Shipping costs would add typically $30/t to this so that DME could be delivered at about $240/t or about $8.4/GJ. This is equivalent to diesel at about $47/bbl.

2.3.3.3 **Methanol-to-Olefins (MTO)**

The conversion of methanol into olefins (MTO) has been studied for over 20 years (Seddon, 2004). It may be seen as a gas-to-solids route if the olefins are converted to resins (plastic). According to Seddon, there are two MTO production routes already at advanced states of development. One route produces ethylene and propylene mixtures, with the relative proportions being variable. The other route produces entirely propylene. Seddon claims that both processes have similar process economics.

He claims further that gas at $1/GJ would produce olefins below $500/t. This is lower than the production costs of olefins from naphtha. Olefins are costly to transport, but are easily converted into commodity resins, at relatively small additional capital cost. Resins are easily transported in containers or solid bulk carriers. These materials sell at typically $800/t. In theory gas to olefins could competitively support gas prices up to $3/GJ, considerably more than that for GTL or LNG.

2.3.7.4.0 **Fischer-Tropsch Gas-to-Liquids (F-T GTL)**

Fisher-Tropsch synthesis is one of the leading GTL technologies to convert natural gas into high value, clean-burning fuel. Most times F-T GTL is simply referred to as GTL. It is the most researched of the GTL processes. This probably explains why GTL is used synonymously with F-T GTL in the literature.

2.3.3.4.1 The History of the F-T GTL Technology

The word 'Fischer-Tropsch" (F-T) is a coinage from the names of the two German chemists that discovered the process in 1923. They were Franz Fischer and Hans Tropsch. They invented a process that could convert synthesis gas to a hydrocarbon mixture which could then be upgraded into petroleum products (Pirog, 2004). They succeeded in producing syngas (a mix of CO and H_2) from coal with an iron-based catalyst (Maisonnier, 2006).

Thackeray (2000), however, credits the origin of the Fischer-Tropsch technology to Badisch Anilin und Soda Fabrik (BASF). BASF announced in 1913 that under high pressures, mixtures of higher hydrocarbons and oxygenated compounds could be produced catalytically from carbon monoxide and hydrogen. Fischer and Tropsch were later to publish their experimental results from a process using alkali-iron catalyst in 1923.

Fischer and Tropsch made their discovery at the Kaiser-Wilheim Institute for coal Research in Mulheim, Germany. This discovery came as a result of the economic sanctions on Germany following World War I. German scientists were consequently driven by the sanctions to explore ways to synthesize liquid petroleum from the country's abundant coal supplies (*Oil Review, 2003).*

The F-T process was put into commercial operation for the first time in Germany in 1936 (Thackeray, 2000). Waddacor (2005b), on his part reports that the F-T

process was first commercialized in 1932 in the Ruhr Valley by Ruhrchemie, a German chemicals company. Thackeray and Waddacor both report, however, that interest in the F-T process subsequently spread in the 1930s and 1940s to several industrialized nations like the UK, France, the US, Japan and China.

The primary motivation during that period, as Waddacor (2005b) reports further, was to strengthen security of energy supply, especially in times of war and political uncertainty. The technology was used by Germany during World War II to produce high quality aviation fuel. Japan also used the process along with Germany, when their access to adequate oil supplies was disrupted by the Allied Forces (Brook; Arianto & Siallagan, 2000; Verghese, 2003; Pirog, 2004; and Maisonnier, 2006).

In 1945, fears over limited or expensive crude oil supplies subsided. There was a boom in the oil industry. Many technological advances, such as cracking and desulphurization, were made in oil refining. These developments extinguished the interests in the evolving F-T technology (Waddacor, 2005b).

It was in South Africa that this interest was rekindled. The South African apartheid government attracted political and economic sanctions. And just as was the case in Germany, there was an in-house research into the F-T process. Sasol, the company incorporated by the South African government for this purpose, took up the F-T technology in 1955 from where the world left it.

Sasol relied on works of Ruhrchemie and Lurgi of Germany and that of Kellogg Co of the US to achieve this feat (Apanel, 2005; Waddacor, 2005b, and Arianto, 2000). All the authors listed in this section agree that use of the F-T process by both Germany and South Africa's Sasol was not subject to strict commercial considerations. The F-T facilities were rather, technological solutions to politically disrupted markets (Pirog, 2004).

2.3.3.4.2 **The F-T GTL Technology**

It is generally agreed that there are three principal stages in an F-T GTL plant:

- The production of synthesis gas. The synthesis gas is made of hydrogen and carbon monoxide in a ratio close to 2:1.
- The Fischer-Tropsch process. Here, the synthesis gas is converted to paraffinic hydrocarbons, which make up the synthetic crude.
- The conversion of the synthetic crude into marketable petroleum products. This stage is also called product workup or hydro-cracking (Thakeray, 2000; Holditch, 2001; Clarke & Ghaemmaghami, 2003; Smith, 2004; Al-Saadoon, 2005; Apanel, 2005; Culligan, 2005; Fiato & Sibal, 2005; and Jacobs, 2005).

Thackeray lists four methods each for generating synthesis gas and for the FT process. His list for synthetic gas generation techniques includes:

I. Steam reforming of the feedstock in the presence of a catalyst;

II. Partial oxidation, where pure oxygen or air is burned together with natural gas at high temperatures and pressures (It could be catalytic or non catalytic).

III. Auto thermal reforming, which maybe seen as a combination of partial oxidation and steam reforming.

IV. Gas-heated reforming of natural gas, steam and oxygen.

Apanel (2005) adds Heat Exchange Reforming (HER) and Compact Reforming (CPR) to the list.

The four FT processes identified by Thackeray, based on reactor types, include the following;

I. Slurry process. The synthesis gas is reacted in slurry with catalyst and molten wax.

II. Fixed bed. The synthesis gas flows through tubes containing the catalysts

III. Fluidized bed processes. The synthesis gas is passed rapidly at high temperatures through the catalyst bed.

IV. Ebullating bed. The catalyst bed is suspended by the action of a circulating fluid stream and the synthesis gas stream.

The third stage, called the product work up or hydro-cracking stage, takes several forms depending on the proprietary technology adopted.

Players in the F-T GTL arena include oil and gas companies, governments of gas-rich countries, and technology companies. The oil companies prominent in the F-T GTL drive include; Shell, BPAmoco, ExxonMobil, Sasol, ChevronTexaco, SasolChevron, Mossgas, ConocoPhillips, Total Fina Elf, Methanex, Reema. The technology companies are; Rentech, Synthroleum, Haldor-Topsøe, Energy International Corp, Synethex, Intevep, Syncrude Technology, Statoil, Petro SA, Marathon (Thackeray, 2000; Waddacor, 2005a&b).

These companies either have demonstration or commercial F-T GTL plants. They employ various proprietary processes for each of the three stages. For instance, Sasol developed its F-T process but relies on Haldor-Topsøe's Auto-Thermal Reforming (ATR) technology to produce the synthetic gas. Cases of interdependency and cooperation between the players abound. On the other extreme, some companies like ExxonMobil and Shell claim to have developed in-house proprietary processes for all the three stages. ExxonMobil and Shell do not rely on external inputs for any of the stages (Fiato & Sibal, 2005).

2.3.3.4.3 The Cost of F-T GTL Technology

A number of studies peg the cost of the various existing F-T technologies in a range of $20,000 to $30,000 per barrel per day (per bpd) (Ahmad, Zughaid & El Arafi, 2002; Abdul-Rahman & Al-Maslamani, 2004; and Verghese, 2003). These values are obtained when the capital expenditure (CAPEX) is divided by the plant

capacity. For instance if a 100,000 bpd GTL plant attracts a CAPEX of $2 billion, it will be quoted as costing $20,000/bpd.

Some authors express the F-T GTL CAPEX regime in terms of cost per barrel. They quote a CAPEX of $ 9-14 per barrel (Patel, 2005). Estimates for a key price for GTL viability revolve around $20/barrel (this includes the CAPEX, OPEX and cost of feedstock) (Pirog, 2004). Other authors just quote the raw CAPEX in US dollars.

The following CAPEX estimates were made in absolute dollars: The ExxonMobil plant in Qatar will reportedly cost $7 billion for a GTL plant of approximately 150,000 – 180,000 bpd. Meanwhile, Shell's 140,000 bpd plant, also in Qatar, is projected to cost $5 billion (Pirog, 2004). Sasol's 34,000 bpd plants have a CAPEX of $0.9 billion for the one in Qatar and $1.7 billion for the one in Nigeria (Maisonnier, 2006).

It should be noted that estimates are usually done with the assumption that the gas feedstock cost is as low as $0.5/MMBTU. Some estimators actually assume zero cost for gas feedstock. Those who base their estimates on zero cost for gas feedstock usually assume the feedstock is associated gas which would otherwise have been flared. The industry target for a profitable F-T GTL investment is widely accepted as $ 20,000/bpd. This is equivalent to a CAPEX of $9-$14 per

barrel or to a total cost of about $20 per barrel. This assumption for profitability holds, provided crude oil prices are higher than $20-25/b (Maisonnier, 2006).

Historically, the cost of the F-T GTL had always been as high as $50,000/bpd, or even higher. Meanwhile, a large conventional refinery has a unit capacity in the order of $15,000/bpd (Verghese, 2003). This is the reason why the F-T GTL process had always been considered an economically unattractive route for gas monetization. This is because its products will not be able to compete with products from conventional refinery. This scenario has changed. Technological advances have reduced the F-T GTL CAPEX drastically.

In 2001, Shell asserted that the capital expenditures for a new GTL facility will decline from $50,000/bpd to $20,000/bpd as a result of scale of economies consistent with improved technology (Pirog, 2004). Analysts have always asserted that present generation F-T GTL process is economically viable at crude oil prices of $15 per barrel (Ahmad, Zughaid, & El Arafi, 2002). Crude oil prices have consistently risen above $50 a barrel for at least three years. The current prices, at the time of this write-up, are over $60/barrel.

Technological advancements bringing the F-T GTL CAPEX down from $50,000/bpd to $20,000/bpd and the consistently high crude oil prices are two developments that have led to the conclusion that F-T GTL is now economically viable beyond any doubts (Thackeray, 2000).

2.3.3.4.4 CAPEX Breakdown

A breakdown of the F-T GTL CAPEX usually attributes about 60% of the total CAPEX to the generation of synthesis gas. The Fischer-Tropsch synthesis itself accounts for about 15%, the product workup accounts for about 10% and the rest is aggregated as 'other costs' (Holditch, 2001; Clarke & Ghaemmaghami, 2003; Smith, 2004; and Culligan 2005).

2.3.7.4.5 Market Share and Unlimited Market Prospects

Estimates for the global energy demand and total global F-T GTL production capacity have been compared. The results show that by 2020, F-T GTL products at 1 million bpd will account for less than 3% of the world market for diesel and other petroleum products (Culligan, 2005). One implication of this is that the market for F-T GTL products is unlimited. The other is that F-T GTL might not have a strong influence on the market. Some experts, however, argue that even a slight change in supply of fuels has a significant effect on the market.

Many experts argue that GTL products will attract premium prices. They back their arguments up with the fact that F-T GTL products have excellent properties (except for its low density) relative to products from conventional refining. These properties surpass the most stringent specifications for content of noxious substances. The table below compares the properties of GTL diesel with the properties and specifications for diesel from conventional refining.

Property/Specification	GTL Properties	EU 2006	USA 2006	CALIFORNIA 2006
Cetane number (Min)	75-85	51	40	48
Specific Gravity (Max)	0.76-0.79	0.84	0	0.85
Sulphur PPM (Max)	<1	50	15	15
Total Aromatics Wt% (Max)	<0.1	11	10	35

Table2.2 *Diesel properties and specifications (Source: Culligan, 2005)*

The properties of GTL diesel do not only make it environmentally friendly, they guarantee superior engine performance. The much higher Cetane Number supports this claim of superior engine performance with GTL diesel. Green car congress reports that *Shell Petroleum* has test run the sale of its GTL diesel. It sold easily at prices higher than those of conventional diesel.

2.3.3.4.6 Future Prospects and Research Efforts into Cost Reduction

One of the major reasons for the renewed interest in F-T GTL is the prospects for monetizing associated gas, which is either being flared or re-injected back in to the oil wells. Neither flaring nor re-injection is favourable. Flaring results in large-scale environmental pollution. Re-injection of associated gas is done with the intention of maintaining reservoir pressure and enhancing crude oil production. However, re-injection has been found to actually hamper production and reduce reservoir recovery (Chang, 2001).

Rather than flare or re–inject this associated gas, why not monetize it? This question is one of the main drivers for the adaptation of F-T GTL synthesis for offshore applications in FPSOs (floating production storage and offloading) vessels and barges. Two of the major researches are in the areas of compact

reformers (proposed by Synthroleum) and ceramic membranes (proposed by consortia of companies and governments). The success of these research efforts will not only solve the flaring problem, it will also help bring the stranded gas from small reservoirs to market (Thackeray, 2000; *Petroleum Economist, 2003*).

The US Department of Energy (DOE), in partnership with several industry players, is supporting the development of Ionic Transport Membranes (called ITM or OTM). The ITM will be used in the generation of synthesis gas. If these research efforts are successful, they have the potential of reducing the F-T GTL CAPEX by between 25% and 50% (Thackeray, 2000; *Petroleum Economist,* 2003).

Other research efforts are geared towards improvement in the energy efficiencies (Carbon and thermal) of the process. If these efforts succeed, Carbon and thermal efficiencies might increase to 90% and 73% respectively from the current 77% and 60%. This success will result in more products being generated from the feedstock than is currently obtainable. This increases the cash realized from product sale for every cubic feet of gas feedstock. It also reduces emission of greenhouse gases (Patel, 2005; Pirog, 2004).

2.4 Synergy Options and Possibilities

Thackeray (2000) reports that the costs of infrastructural facilities can amount to as much as 30% of the overall capital costs of a plant in a remote location, where

no such facility already exists. Experts believe that cost reductions could be achieved if the gas monetization options are synergized rather than seen as mutually exclusive.

The argument is that some of these options share similar infrastructure. It is also argued that the waste generated during some of these processes is valuable input for some others. Many authors cite the synergy arrangements and benefits possible with integrating LNG and GTL plants (*Axens, IFP Group Technologies*, 2005; Suehiro et al., 2004; Thackeray, 2000).

2.5 Comparison of the Monetization Options

Authors that have carried out economic comparisons of the gas monetization options arrive at different conclusions. Their conclusions on the most viable gas monetization options are never the same.

Pirog (2004) estimates that the cost of a new 150,000 bpd capacity refinery in the US is $2.5 billion. He also claims that the additional investment required to modify a conventional refinery is between $4 and $13billion. The modification is to allow the refinery to produce products that meet current and future fuel requirements (it should be noted that fuels from F-T GTL meet and surpass the most stringent of the current and future requirements; except on density). He adds that the downstream price differential between natural gas and diesel fuel is

relevant to the choice of F-T GTL or LNG investment. This is despite the fact that LNG and GTL products are for different markets.

Verghese (2003) highlights issues on the viability of LNG, PNG, CNG, GTS, GTW, F-T GTL, DME, and methanol. He did not commit to ranking them in the order of viability. He stops at stating the conditions for viability of each of the options. Ahmad et al. (2002) compare DME and F-T GTL. They fail to present a conclusion on how these two options compare. They only conclude that the F-T GTL route is viable at crude oil price of $15 per barrel. Apanel (2005) concludes his treatise of F-T GTL asserting that F-T GTL will be viable at crude oil prices above $35 per barrel and at natural gas feedstock cost of $0.5 /MMBtu.

Al-Saadoon (2005) concludes that the viability of GTL depends on four factors: CAPEX, OPEX, natural gas feedstock prices and crude oil prices. He also agrees that low natural gas cost coupled with high crude oil prices will ensure the economic viability of GTL plants. He suggests that stranded natural gas, especially associated gas in regions of zero flare policy, is an ideal feedstock for GTL plants.

Seddon (2004) compares F-T GTL, methanol, DME, MTG, and LNG. He says gas feedstock must be available at less than $1/GJ for GTL to be feasible. He concludes that, since this price for gas feedstock can not always be guaranteed, that LNG remains the preferred option for gas utilization of large reserves. He

adds that for reserves too small for the LNG route, chemical methanol is the option to choose. Seddon, however, sees the speculative GTS, if it eventually becomes commercial, as a potential alternative to LNG.

Chang (2001) develops a model to compare CNG, GTS, F-T GTL, and GTW vis-à-vis LNG and PNG. He concludes that CNG, GTS, and GTW (in decreasing order of viability) represent the best approaches for producing and transporting stranded gas. He admits that the reason why F-T GTL ranked fourth is because of its high CAPEX of $40,000/bpd. This high CAPEX for F-T GTL, applied by Chang in his model, is no longer tenable. A CAPEX in the region of $25,000/bpd is more realistic by current estimates. Chang holds that the PNG and LNG options are the poorest options. They require large CAPEX as well as large proven gas reserves. They also require, according to Chang, long-term contracts.

Subero et al. (2004), in their model, limit their comparison to three options: LNG, CNG, and PNG. They conclude that PNG and CNG are the best for shorter distance gas transport projects; LNG is best for longer distances. Abdul Rahman and Al-Maslamani (2004) compare only LNG and F-T GTL. They report that both options have a comparable CAPEX and profitability. As a result, they conclude that no clear economic preference can be made between LNG and GTL. They, however, add that F-T GTL should be preferable where the gas reserves can not support LNG, and where PNG is not technically feasible.

2.6 Conclusion

It is obvious that the F-T GTL technology is in the middle of stiff competition. It competes with gas monetization options upstream for a share of the gas reserves. Downstream, it competes with the products of crude oil refineries for a share of the market. These give rise to a competitive landscape for the F-T GTL technology. Decisions to adopt the technology can, therefore, not be made without due consideration of the entire competitive landscape.

Unfortunately, none of the available authors presented a holistic assessment of this competitive landscape. They typically limit their comparison to few of the options mentioned above. The authors evaluate the viability of the F-T GTL process with respect to only the options upstream or the options downstream. This is unfortunate because it could lead to misleading results. Wrong decisions and policies could be made based on these misleading and incomplete evaluations.

This obvious gap in the gas monetization and related literature is what I hope to fill with my current research. I shall be examining the economic viability of the F-T GTL technology with respect to the entire competitive landscape. I hope that my evaluation shall lead to more reliable results.

CHAPTER THREE

3 MODEL DESIGN

3.1 Design of the Competitive Landscape

3.1.1 Options in the competitive landscape

The options competing with F-T GTL in the competitive landscape once again include:

1. LNG
2. CNG
3. PNG
4. GTW
5. GTS
6. DME
7. MTO
8. Methanol
9. Crude Oil Refining

Meanwhile, I shall be presenting F-T GTL from six scenarios:

Premium on Products	Current CAPEX	Future CAPEX (35% reduction)
No Premium	F-T GTL (CCNP)	F-T GTL (FCNP)
Low Premium (5%)	F-T GTL (CCLP)	F-T GTL (FCLP)
High premium (20%)	F-T GTL (CCHP)	F-T GTL (FCHP)

Table 3.1: *Six F-T GTL Scenarios*

Key

- F-T GTL (CCNP): Plant is built at current CAPEX, products attract no premium
- F-T GTL (CCLP): Plant is built at current CAPEX; products attract a low premium (5%)
- F-T GTL (CCHP): Plant is built at current CAPEX; products attract a high premium (20%)
- F-T GTL (FCNP): Plant is built at future CAPEX (this is 35% less than current CAPEX); products attract no premium
- F-T GTL (FCLP): Plant is built at future CAPEX (this is 35% less than current CAPEX); products attract a low premium (5%)
- F-T GTL (FCHP): Plant is built at future CAPEX (this is 35% less than current CAPEX); products attract a high premium (20%).

In addition, two scenarios shall be considered for refining

I. The current scenario; at current CAPEX (Plant is unmodified)
II. A possible future scenario where refiners are compelled to invest additional $4-$13 billion (Pirog, 2004) to modify their refineries in order to produce environmentally compliant fuel.

LNG, CNG, PNG, GTS shall be evaluated for two distances each. These are 500 km and 6482km. These two distances allow for evaluation of the effect of distance on the competition. In summary, we have 20 base-case options/possibilities in our competitive landscape.

3.1.2 Mode of Comparison

The purpose of this dissertation is to establish the most profitable of the options in the competitive landscape. I intend to provide ranking/rankings of these options based on the outcomes of my economic evaluation.

Of the available economic tools for evaluating the economic viability of projects, the net present value (NPV) provides the most reliable result (Ross, Westerfield, & Jordan, 1996). I shall employ this tool in evaluating my competitive landscape.

The NPV of a proposed project is based on

- an assumed or known discounting rate;
- estimated future annual cash flows throughout the project lifecycle
- the initial capital investment (CAPEX); and

- the salvage value of the project (plant, in our case)

The NPV is expressed as:

$$NPV(i) = \sum_{n=0}^{N} \frac{A_n}{(1+i)^n} \tag{3.1}$$

$$= -A_0 + \frac{A_1}{(1+i)} + \frac{A_2}{(1+i)^2} + \ldots + \frac{A_{N-1}}{(1+i)^{N-1}} + \frac{A_N}{(1+i)^N} + S_V \tag{3.2}$$

Where:

A_0 = Initial CAPEX

A_n = annual cash flow for the nth year

N = project lifecycle

S_V = Salvage value of the facility

i = discount rate

Now, equation 3.2 assumes that the CAPEX is expended entirely at the start (year zero) of the project. This is hardly the case. In reality, it takes several years to complete the project and bring it on-stream. This is typically 3 or 4 years for chemical plants like the ones we have in our competitive landscape. We shall assume a three-year construction for our model. The NPV in the case of a plant constructed in 3 years, is expressed as:

$$NPV(i) = -A_0 - \frac{A_1}{(1+i)} - \frac{A_2}{(1+i)^2} + \frac{A_3}{(1+i)^3} + \frac{A_4}{(1+i)^4} + \ldots + \frac{A_{N-1}}{(1+i)^{N-1}} + \frac{A_N}{(1+i)^N} + S_V \tag{3.3}$$

Here A_0, A_1, and A_2 are the portions of the CAPEX made during the first, second and third years of the plant construction.

3.1.3 Interpretation of results from NPV calculations

NPVs obtained after calculation could be positive, negative or zero.

When **NPV > 0** the project will be profitable and could be considered.

When **NPV< 0,** the project will not be profitable, it should be discarded.

When **NPV = 0,** the project could go either way (either profitable or not); the reaction is that of 'indifference'.

In the case of mutually exclusive projects, the projects are ranked based on the values of their NPV. The project with the highest NPV is the most profitable.

For the purpose of our model in this dissertation, we shall therefore rank all the options/possibilities in our competitive landscape using the relative NPVs. All projects that have negative NPVs will be classified as unprofitable. They should therefore be avoided.

Let us take another look at the NPV equation from equation 3.3

$$NPV(i) = -A_0 - \frac{A_1}{(1+i)} - \frac{A_2}{(1+i)^2} + \frac{A_3}{(1+i)^3} + \frac{A_4}{(1+i)^4} + \ldots + \frac{A_{N-1}}{(1+i)^{N-1}} + \frac{A_N}{(1+i)^N} + S_V \quad (3.3)$$

Recall that

A_n = the cash flow in the nth year

S_v = salvage value of the plant at the end of its lifespan

We shall make the following assumptions in this thesis where applicable:

I. project lifecycle from start-up= 25 years

II. construction period of plant = 3 years

III. N = (25 + 3) = 28 years

IV. Salvage value of plant = the cost of dissembling the plant

$$S_V - Cost_{plantdessembly} = 0 \tag{3.4}$$

Equation 3.3 now becomes:

$$NPV(i) = -A_0 - \frac{A_1}{(1+i)} - \frac{A_2}{(1+i)^2} + \frac{A_3}{(1+i)^3} + \frac{A_4}{(1+i)^4} + \ldots + \frac{A_{N-1}}{(1+i)^{N-1}} + \frac{A_N}{(1+i)^N} \tag{3.5}$$

Now A_n = Cash flow in the nth year

Annual cash flow = (annual revenue from product sale) – (annual OPEX)

(OPEX: operating expenditure)

$$\Rightarrow A_n = \mathrm{Re}v - OE \tag{3.6}$$

Rev = Revenue from product sale in the nth year

OE = OPEX in the nth year

OPEX = Maintenance (MC) + Overhead Cost (OC) + Running Cost (RC) + Shipping Cost (SC) + Feedstock Cost (FS)

$$\Rightarrow OE = MC + OC + RC + SC + FS \tag{3.7}$$

In this thesis, we shall group maintenance cost, overhead cost, and running cost together as Operating Cost (OPC)

$$\Rightarrow OPC = MC + OC + RC \tag{3.8}$$

Equation 3.7 now becomes:

$$\Rightarrow OE = OPC + SC + FS \tag{3.9}$$

While equation 3.6 becomes:

$$A_n = \mathrm{Re}v - \{OPC + SC + FS\} \tag{3.10}$$

For each of the 20 options we are considering in our model, we shall establish the CAPEX as well as the annual cash flow (A_n) for the entire project lifecycle. After these values are obtained, it shall then be possible to obtain the corresponding NPVs at the specified discount rates (*i*).

3.1.4 Notes and General Assumptions

Firstly, a list of the notations, symbols and acronyms used in this thesis is provided on page xiii. Reference to notations should therefore be made to the list. Secondly, the units employed in this work are guided by popular usage by authors and other researchers in this area of research. SI units was not used if it did not add any significant value to the point being made.

For an F-T GTL plant with a thermal efficiency of 60%, 10 MSCF of 1000 BTU/SCF natural gas is required to produce 1 barrel of GTL products (Al-Saadoon, 2005; Abdul-Rahman & Al-Maslamani, 2004; and Maisonnier, 2006).

Note that 10 MSCF of Natural gas (NG) = 10,000 SCF of NG; and 1000 BTU/SCF NG represent the heating value of the NG. This implies that 1 barrel of GTL products requires 10,000 SCF feed of NG. We shall use this conversion rate to determine the natural gas feedstock rate for our F-T GTL plants.

Below is a table of the sizes of the GTL plants that will be used for the analysis in this thesis along with the corresponding gas feedstock required.

GTL Plant Size (bpd)	Gas feedstock required daily (Billion Cubic Feet (BCF))
15000	0.15
25000	0.25
34000	0.34
50000	0.50
75000	0.75
100000	1.00

Table 3.2 F-T GTL Plant size and Required Gas Feedstock

Table 3.2 shall be used to obtain the corresponding sizes of the plants for the other gas monetization options (LNG, CNG, GTW, GTS, and PNG), for each of the listed F-T GTL sizes. For instance, an LNG plant that corresponds in size to a 15,000 bpd GTL plant will be one that handles the same quantity of gas (0.15 BCF per day).

To illustrate the prospects for F-T GTL technology; (and indeed, other gas monetization options) consider the following. The global proven gas reserves of 6348 TCF (using BP's estimates) can support 1,400 different GTL plants each of a capacity of 50,000bpd and a lifecycle of 25 years. This is based on a thermal efficiency of 60% (60% thermal efficiency is the level of current technology), and on a gas stream with a heating value of 1000 BTU/SCF. The number of plants is obtained as follows:

Total global gas reserves = 6348 TCF

Plant production lifecycle = 25 years

Gas quantity used in a year = $6348/25 = 253.92TCF = 253.92 \times 10^{12} SCF$

1 barrel of GTL products requires 10,000 SCF of gas

50,000 bpd GTL plant produces 50,000*365 barrels in 1 year

$\Rightarrow$ the number of 50,000 bpd GTL plants required to use up 253.92 * 10^{12} SCF gas in one year = $\frac{253.92 \times 10^{12}}{50000 \times 365 \times 10000} \approx 1400$ plants.

It is clear that the global gas reserve is tremendous. If F-T GTL is embraced, there is limitless room for its expansion.

Furthermore, the gas reserves are unevenly distributed over 60 different countries (see appendix 2); while there are numerous F-T GTL technologies. All these preceding points have several implications;

1. CAPEX will vary and will depend on the plant location as well as the technology employed. It is more expensive to site a plant in some locations than it is in others. The Sasol GTL plants in Nigeria and Qatar are both 34,000 bpd capacity and use same technology. They, however, have different CAPEXS of $1.7 billion and $0.9 billion respectively. The reason for this difference in CAPEX has been attributed to the location of the Nigerian plant and the resulting complexity. The plant in Nigeria is to be located in a swamp, requiring large quantities of sand landfill to support heavy reactors and other equipment at the site. These conditions unfortunately will also limit opportunities to install modularized units that might be built more cheaply off-site. The developers must also deepen and maintain seabed dredging at the plant site, on the Niger River at the mouth of the Bight of Benin (Alexander's Gas & Oil Connections, 2001).

2. In addition, some F-T GTL technologies are more expensive than others. However, F-T GTL CAPEX for all currently available technologies and possible locations fall within the $20,000/bpd to $50,000/bpd range.

3. The size of the plant will be determined by the size of the gas field. The size of the gas field a company owns may be politically motivated.

A small gas field may be commercialized using a 15,000bpd F-T GTL plant while larger fields will be best monetized by larger plants. This is to allow for the benefits of economies of scale.

3.1.5 Effect of Plant Size on CAPEX (Economies of Scale)

Capital equipment costs follow the rule of six-tenths power of capacity (Kerzner, H. 2006). Meanwhile, Al-Saadoon (2005), states that economies of scale relate CAPEX to plant capacity and may be expressed as follows:

$$\text{Cost ratio} = (\text{capacity ratio})^{Y} \tag{3.11}$$

Where

$$\frac{Cost}{BaseCost} = \left(\frac{Capacity}{BaseCapacity}\right)^{Y} \tag{3.12}$$

$$\Rightarrow Cost = BaseCost \times \left(\frac{Capacity}{BaseCapacity}\right)^{Y} = \left(\frac{BaseCost}{(BaseCapacity)^{Y}}\right) \times (Capacity)^{Y} \tag{3.13}$$

$$\therefore Cost = Cons\tan t \times (Capacity)^{Y} = k \times (Capacity)^{Y} \tag{3.14}$$

$$\Rightarrow k = \left(\frac{BaseCost}{(BaseCapacity)^{Y}} \right) \tag{3.15}$$

Where:

k = constant

Y = a constant reflecting the degree to which a particular process facility benefits from economies of scale. When *Y* = 1.0, it is implied that the facility does not benefit from economies of scale. For example, the construction of parallel trains (instead of larger trains) would yield Y values approaching 1.0.

The above relations and claims are the same with the ones provided by Hendrickson and Au (2003).

The *Y* value for refineries and petrochemical plants are typically between 0.5 and 0.8 (Al-Saadoon, 2005). Hendrickson and Au (2003) hold that this Y value is generally between 0.5 and 0.9 depending on a specific type of facility. They went ahead to state that 0.6 is often used for chemical processing plants.

There is a need for us to decide the values for Y. We could either adopt 0.6 or employ values that apply specifically to the competing option being considered. However, Y values are not readily available, except for the one provided by Al-Saadoon (2005) for GTL plants.

Al-Saadoon, (2005) estimates the *Y* value for GTL plants at 0.6615.

At this point, there are three alternatives

- Adopt 0.6 for all the competing options
- Adopt 0.6 for all the competing options, and 0.6615 for GTL options
- Adopt 0.6615 for the options

I chose to adopt 0.6615 for all the competing options. This choice is informed by the fact that

- 0.6 is quite general for plants
- 0.6615 has already been empirically established for GTL process (Al-Saadoon, 2005),
- All the options being considered are within the same industry and as a result, 0.6615 may well be closer to the actual values
- The use of broad range of values in the simulation makes up for the assumption and reduces the chances of major errors in the results

Notes:

The economies of scale relation employed above for CAPEX shall be adopted for OPEX. This is justified as follows

- OPEX also benefits from economies of scale, and a use of a constant value per unit for the OPEX of different plant capacities is an oversimplification (Subero et. al, 2004)

- If the point just stated above holds, then it is necessary to use a scaling model. The limitations discussed in the previous paragraph also compelled me to toe the same line as I toed in the previous paragraph.

I shall now demonstrate the use of this relation with a GTL example. Firstly, I shall obtain the various k values for the different F-T GTL CAPEX tabulated below in *Table 3.3.* I shall use 34,000 bpd as my base case plant capacity where applicable.

From equation 3.15

$$k = \left(\frac{BaseCost}{(BaseCapacity)^{\gamma}} \right)$$

Now;

A $20,000/bpd GTL plant will amount to a CAPEX of

$$20000 \times 34000 = \$0.68 \text{ billion}$$

The corresponding k is

$$\left(\frac{0.68 \times 10^{9}}{(34000)^{0.6615}} \right) = 683810.25$$

Sasol's 34,000 bpd GTL plant in Qatar cost $0.9 billion (Maisonnier, 2006). The k value in this case is

$$\left(\frac{0.9 \times 10^{9}}{(34000)^{0.6615}} \right) = 905042.98$$

*Note that this Sasol plant corresponds to a CAPEX of

$$\left(\frac{0.9\times10^{9}}{(34000)}\right)\approx \$26{,}471/\text{bpd}$$

The values for k for various CAPEXs are obtained using the above procedure. The results are tabulated below.

Base Capacity (bpd)	F-T GTL CAPEX/bpd	Total CAPEX ($ Billion)	k
34000	20,000	0.68	683810
34000	26,471	0.9	905043
34000	30000	1.02	1025715
34000	35000	1.19	1196668
34000	40000	1.36	1367621
34000	45000	1.53	1538573
Economies of scale Index (Y)		0.6615	

Table 3.3: Economies of scale factor (k) for various GTL plants sizes

As stated earlier, the base capacity to be used for the F-T GTL analysis is 34,000bpd. Sensitivity analysis shall be done where necessary.

3.1.6 Cost of Natural Gas Feedstock (FS)

Published estimates put the cost of natural gas feedstock into GTL plants at between $0/MMBTU and $1/MMBTU. Many authors claim that for GTL to be viable, the natural gas feedstock must not be more than $1/MMBTU (Al-Saadoon, 2005; Apanel, 2005; Seddon, 2004; Verghese, 2003; Ahmad et al., 2002; and Chang, 2001).

I shall use the $1/MMBTU cost of gas feedstock for the computation of my NPVs for all the gas monetization options. After this, I shall use different gas feedstock values in my sensitivity analysis.

A $1/MMBTU gas feedstock is equivalent to $10/barrel of GTL products. This is obtained as follows:

$$1MMBTU = 10^6\, BTU = 10^3\, SCF \equiv \$1$$

$$\Rightarrow 10000SCF \equiv \$10$$

Meanwhile, 10,000 SCF of a 1,000 BTU/SCF gas gives 1 barrel of GTL products at 60% thermal efficiency.

$$\Rightarrow 10000SCF \equiv \$10 \equiv 1 \text{ barrel}$$

3.1.7 Shipping Cost (SC)

Shipping cost shall be added to the operating cost, where applicable. Sensitivity of the NPV to the shipping distance and shipping cost shall be investigated where applicable.

When it comes to shipping of products in the oil and gas industry, there are two possible scenarios;

- A Free on Board origin (FOB) contract; where the cost of shipping the product from the plant is paid by the purchaser. Ownership of the goods is transferred to the buyer as soon as it leaves the point of origin. It can be either the buyer or seller that arranges for the transportation.

- A Cost, Insurance and Freight (CIF) contract; where the company making the product is responsible for the shipping of the product. A CIF price means that the selling price includes the cost of the goods, the freight costs and also the cost of marine insurance.

In this dissertation, we shall assume FOB contract as much as possible. This means that shipping costs shall be ignored. The exceptions will be in the cases of LNG, CNG and GTS. The reason for this exception is because these three options employ specialized ships. They cannot make use of conventional ships.

3.1.8 Discount Rate

Four discount rates will be applied in the computation of the NPV. These rates are 5%, 10%, 15%, and 20%. This implies that for each option, four NPVs shall be obtained. Comparison shall be based on the results of the NPVs corresponding to 10% discount rate.

3.2 The Monte Carlo Simulation

3.2.1 Introduction to Monte Carlo Simulation

The expression "Monte Carlo Method" is actually very general. Monte Carlo (MC) methods are stochastic techniques- meaning they are based on the use of random numbers and probability statistics to investigate problems. MC methods can be found used in everything from economics to nuclear physics to regulating the flow of traffic. Of course the way they are applied varies widely from field to

field. But, generally speaking, to call something a "Monte Carlo" experiment, all that is needed is the use of random numbers to examine some problem.

The Monte Carlo method encompasses any technique of statistical sampling employed to approximate solutions to quantitative problems. In general, Monte Carlo methods are used in mathematics to solve various problems by generating suitable random numbers and observing that fraction of the numbers obeying some property or properties. The method is useful for obtaining numerical solutions to problems which are too complicated to solve analytically.

The use of MC methods to model physical problems allows us to examine more complex systems than we otherwise can. Solving equations which describe the interactions between two atoms is fairly simple; solving the same equations for hundreds or thousands of atoms is impossible. With MC methods, a large system can be sampled in a number of random configurations, and that data can be used to describe the system as a whole.

Stanislaw Ulam, John von Neuman and Nicholas Metropolis are the 3 individuals who are credited with inventing this concept in 1946, with Ulam and Metropolis later publishing the first paper on Monte Carlo simulation later in 1949. The method was named after the casinos of the same name.

3.2.2 Application of Monte Carlo Simulation to the Competitive Landscape

To apply the Monte Carlo simulation in an analysis, there must be elements of uncertainty. I shall identify the situations of uncertainty where applicable in the analysis presented in this chapter.

I made 1000 iterations for each simulation. This means that 1000 NPVs are generated for each simulation at a specific discount rate. The mean of these 1000 vales is obtained. However, comparison will not be made based on the mean. This is because the mean is not a conclusive criterion of comparison (Winston, 2003).

As a result, I shall evaluate the lower and upper bounds of the 95% confidence interval of mean for each of the 1000 iterations. This way, we have 95% confidence that the true mean of the NPVs obtained are within the interval provided by the lower and upper bounds. Since ranking is based on the highest NPVs, we shall adopt the lower bound as the criterion of comparison.

In the event that two or more of the competing options have intervals that overlap significantly, it is assumed that the ratings of the options will not matter. Although the lower bound shall still be determining criterion for rating, options that have overlapping intervals shall be so noted.

The formula for obtaining the 95% confidence interval is provided by Winston (2003) and given as:

$$MeanNPV \pm \left(\frac{1.96 \times S\tan dardDeviation}{\sqrt{NumberOfIterations}} \right) \qquad 3.16$$

Note that this relation only applies to normally distributed systems (which have been assumed in this work). The normal distribution is assumed for the simple reason that information on the actual distributions was not available at the time of this research work. Results reported in this study should be assessed with this assumption in mind.

The higher value is the upper bound and the lower value is the lower bound. The results from the simulation will take the following general format as given in the *Table 3.4.*

LNG-01	Mean ($ Billion)	Lower Bound ($ Billion)	Upper Bound ($ Billion)
NPV1 (5%)	19.46	18.68	20.25
NPV2 (10%)	9.78	9.36	10.20
NPV3 (15%)	5.06	4.86	5.30
NPV4 (20%)	2.50	2.36	2.64

Table 3.4 Typical Simulation Result

LNG-01 represents a specific scenario with certain sets of defined parameters. The model turns out four sets of NPVs for each simulation. Each NPV (NPV1, NPV2, NPV3, and NPV4) corresponds respectively to a discount rate (5%, 10%, 15%, and 20%) as shown in *Table 3.4.*

We shall start the application of Monte Carlo with the six F-T GTL scenarios.

3.2.2.1 Fischer-Tropsch Gas-to-Liquids (F-T GTL) Design

Since the size of the F-T GTL plant is dependent on the size of the gas field available to the oil and gas company, it may be argued that there is a probability attached. This is because an exploration for gas will not yield a predetermined size of gas reserves.

I have developed a table in which I attached probability values to plants sizes based on the frequency of the sizes of currently planned, proposed or running F-T GTL plants. These data are culled from four sources (Holditch, 2001; Maisonnier, 2006; Oilfield Review, 2003 and www.lngexpress.com). The probability mass function (PMF) and the corresponding cumulative density function (CDF) are:

PMF	CDF	Plant Size(bpd)	Frequency
0.20	0.2	15000	6
0.07	0.27	25000	2
0.06	0.33	34000	2
0.20	0.53	50,000	6
0.20	0.73	75000	6
0.10	0.83	100000	3
0.17	1	150000	5
Total			30

Table 3.5 Frequency of F-T GTL Plant Sizes

Recall the following equations

$$NPV(i) = \sum_{n=0}^{N} \frac{A_n}{(1+i)^n} \qquad (3.1)s$$

$$NPV(i) = -A_0 - \frac{A_1}{(1+i)} - \frac{A_2}{(1+i)^2} + \frac{A_3}{(1+i)^3} + \frac{A_4}{(1+i)^4} + \ldots + \frac{A_{N-1}}{(1+i)^{N-1}} + \frac{A_N}{(1+i)^N} \quad (3.5)$$

$$\Rightarrow A_n = \mathrm{Re}v - OE \quad (3.6)$$

$$A_n = \mathrm{Re}v - \{OPC + SC + FS\} \quad (3.10)$$

I shall evaluate the values for each of the components of equation 3.10.

Revenue (Rev): This is the same as the gross annual income. This is the product of

- Plant size in bpd
- 365 days in a year (Although in reality no plant runs for 365 days; I chose to use 365 days because there are no stipulations of the exact number of days a plant runs for. In addition, my choice of 365 days is with the knowledge that if 365 days is used consistently for all the options compared then one would expect that there will be no effect on the final outcome, since the final outcome is only a relative comparison of NPVs), and
- Average value of products ($/barrel). This equals the value of refinery products, when no premium is charged. Premium is charged as a percentage of the refinery products. We assume that low premium is 5% of price of refinery products; while high premium is 20%.

Operating Cost (OPC): Operating cost applied in the computation of NPV shall be 6% of CAPEX *(Al-Saadoon, 2005).*

Shipping cost (SC): We have assumed FOB contracts for F-T GTL products. This means that shipping cost is not considered in the cash flow.

Feedstock Cost (FC): The feedstock is gas. Gas cost employed in the simulation are 0, 1, 5 and 10 ($/MMBTU).

Table 3.6 below presents the CAPEX and economies of scale factor (k) of F-T GTL plants based on sizes.

*PMF	CDF	Cost/bpd	k	Total CAPEX ($ Billion)
0.14	0.14	20000	683810	0.68
0.14	0.28	26471	905043	0.90
0.14	0.43	30000	1025715	1.02
0.14	0.57	35000	1196668	1.19
0.14	0.71	40000	1367621	1.36
0.14	0.86	45000	1538573	1.53
0.14	1.00	50000	1709526	1.70

Table 3.6 CAPEX and economies of scale factor *for Different F-T GTL Plant Sizes*

(Please note that the values of the PMF reported here are rounded)

As explained in section 2.3.3.4.3 earlier, the CAPEX for F-T GTL ranges from $20,000/bpd to $50,000/bpd, depending on location and technology. We assumed a uniform discrete distribution for this CAPEX. As a result of the variance of the CAPEX of F-T GTL from $20,000/bpd to $50,000/bpd, a random distribution shall be incorporated in the base cost for F-T GTL. However, single

based cost shall be used for the other options because the discrepancy or variance in cost is less pronounced.

The economies of scale factor (k) shown in Table 3.6 takes 34,000 bpd as base capacity.

Going back to equation 3.15

$$k = \left(\frac{BaseCost}{(BaseCapacity)^Y} \right)$$ Where Y =0.6615

The different k values were obtained when the various base costs (CAPEX/bpd) were plugged into equation 3.15. The total CAPEX is obtained by multiplying each of the cost/bpd by the base capacity of 34,000 bpd.

In the simulation, each k was used as a baseline in computing the CAPEX of the various plant capacities provided by *Table 3.5.* In any typical trial of the simulation, plant capacities are assigned to that trial according to the CDF in *Table 3.5*; while the base CAPEX/bpd (and the corresponding **k**) is assigned to that trial according to the CDF in *Table 3.6.*

Three CAPEX values may be identified:

- CAPEX/bpd
- Apparent CAPEX; this is the product of CAPEX/bpd and total barrels produced per day
- Actual CAPEX; this is the Pseudo-CAPEX factored with the economies of scale.

The Actual CAPEX is used in obtaining the OPEX (OPC + FS) and the NPV. This Actual CAPEX is also the *Current CAPEX,* since it is based on current costs.

From *Table 3.1*, I identified six possible F-T GTL scenarios. The proceeding explanation applies to all six scenarios, except for slight modifications in each case.

Scenario 1: F-T GTL (CCNP): Plant is built at current CAPEX, products attract no premium. This is a major baseline to be observed in this thesis.

Scenario 2: F-T GTL (CCLP): Plant is built at current CAPEX; products attract a low premium (5%). The gross income for this scenario is obtained by multiplying the income obtained for scenario 1 by 1.05. The CAPEX is the same with that of scenario 1.

Scenario 3: F-T GTL (CCHP): Plant is built at current CAPEX; products attract a high premium (20%). CAPEX is same with scenario 1, while gross income is 1.2 times that of scenario 1.

Scenario 4: F-T GTL (FCNP): Plant is built at future CAPEX (this is 35% less than current CAPEX); products attract no premium. Gross income is same with Scenario 1, while the CAPEX is 65% of that of scenario1.

Scenario 5

F-T GTL (FCLP): Plant is built at future CAPEX (this is 35% less than current CAPEX); products attract a low premium (5%). CAPEX and gross income are respectively 65% and 105% of those of scenario 1.

Scenario 6

F-T GTL (FCHP): Plant is built at future CAPEX (this is 35% less than current CAPEX); products attract a high premium (20%). CAPEX and gross income are respectively 65% and 120% of those of scenario 1.

3.2.2.2 Methanol Synthesis Design

32.16 PJ/a of NG is required to produce 2.5kt/d (kiloton/day) of methanol (Seddon, 2004).

Now,

1 kJ = 0.948 BTU

$$\Rightarrow 1PJ = 0.948\times10^{-3}\times10^{15}\,BTU$$

$$= 0.948\times10^{12}\,BTU$$

$$32.16PJ = 32.16\times0.948\times10^{12}\,BTU$$

Recall the natural gas we have based our model on has a heating value described by:

$$1000BTU \equiv 1SCF$$

32.16 PJ of NG $\equiv 32.16\times0.948\times10^{12}\,BTU$

$$= 32.16\times0.948\times10^{12}\times10^{-3}\,SCF$$

$= 3.048768 \times 10^{10} SCF$

$\therefore 32.16 PJ = 30.49 BSCF$ (Billion Standard Cubic Feet)

This implies that an annual flow of 30.49 BCF NG will produce 2.5 kt/d or 912.5 kt/a methanol.

This implies that 84,000,000 SCF/a NG will produce 2.5 kt/d of methanol.

Now we obtain the sizes of the methanol GTL plants that are equivalent to the base sizes of the F-T GTL plants, as we have it in our model. This equivalence will be derived based on gas consumption.

From *Table 3.2*, 0.15 BCF NG feeds a 15000 bpd F-T GTL plant. We now obtain the equivalent methanol plant that requires this feedstock.

Recall that 84,000,000 SCF/a NG produces 2500t/d of methanol.

$$\Rightarrow 0.15 \times 10^9 SCF \approx \frac{2500 \times 0.15 \times 10^9}{84000000} \approx 4490 t/d$$

Using this procedure, we can generate values for the capacities of the methanol GTL plants that correspond to the other F-T GTL plants. The result is tabulated as shown in *Table 3.7*.

F-T GTL (bpd)	NG Feedstock (BCF/D)	Methanol GTL (t/d)
15000	0.15	4490
25000	0.25	7483
34000	0.34	10176
50000	0.50	14965
75000	0.75	22,448
100000	1.00	29930
150000	1.50	44895

Table 3.7 Methanol Plant Sizes

Next, we establish the cost streams for these plants using the economies of scale index of 0.6615 and equation provided by Al-Saadoon (2005). Meanwhile, according to Seddon (2004), an 8500kt/d methanol plant has a CAPEX of $3225.72 MM (million). We shall use this as our base cost and capacity.

$$8500kt/a = \frac{8500 \times 1000}{365} = 23{,}287.67t/d$$

Now, from equation 3.13, $$Cost = \left(\frac{BaseCost}{(BaseCapacity)^{Y}} \right) \times (Capacity)^{Y}$$

For a methanol plant of 4489.52t/d capacity,

$$Cost = \left(\frac{3225.72 \times 10^{6}}{(23{,}287.67)^{0.6615}} \right) \times 4489.52^{0.6615} = \$1{,}085{,}682{,}694$$ =$ 1.09 billion

The CAPEX for other sizes are calculated and tabulated as shown.

Plant Size (t/d)	Total CAPEX ($ Billion)
4490	1.09
7483	1.52
10176	1.87
14965	2.41
22448	3.15
29930	3.81
44895	4.98

Table 3.8 CAPEX for Methanol Plants

Seddon (2004) also puts the annual operating cost at 2.5 % of the CAPEX. We shall adopt this as our operating cost. We shall assume an FOB contract for the sale of methanol. This implies that the OPEX will be the sum of the operating cost and the feedstock cost. For the simulation, a distribution is assumed for the plant sizes. This distribution is based on the normal distribution.

3.2.2.3 Methanol-to-Olefins (MTO) Design

Based on figures supplied by Seddon (2004), 62.1 PJ of NG is required to produce 559kt/a of MTO.

62.1 PJ = $58.8708*10^9$ SCF

$\Rightarrow 58.8708\times10^9 SCF$ produces 559kt/a MTO

$\Rightarrow 161{,}289{,}863 SCF$ NG will produce 1532 t/d MTO.

Using this relationship, we now obtain the annual gas requirements for the various plants sizes used in our model.

For a 0.15 BCF/D gas feed,

The capacity of an MTO plant to utilize an NG feedstock per day of 0.15 BCF is

$$\frac{1532\times0.15\times10^9}{161289863} = 1424 1 t/d$$

Using this relation, we can generate values for the other MTO plant sizes. The result is tabulated below.

F-T GTL (bpd)	NG Feedstock BCF/D	MTO Plant Size (t/d)
15000	0.15	1424
25000	0.25	2374
34000	0.34	3228
50000	0.50	4748
75000	0.75	7122
100000	1.00	9495
150000	1.50	14243

Table 3.9 MTO plant sizes

We now establish the cost streams for these plants using the Al-Saadoon relations.

CAPEX for a 559kt/a MTO plant is $900 MM; OPEX (excluding feedstock cost) is 2.55 of CAPEX (Seddon, 2004). We shall assume an FOB contract for the sale of the products.

Now, 559 kt/a = 1531.51 t/d

From equation 3.13,

$$Cost = \left(\frac{BaseCost}{(BaseCapacity)^{Y}} \right) \times (Capacity)^{Y}$$

For an MTO plant of 1424 t/d capacity,

$$Cost = \left(\frac{900 \times 10^{6}}{(1531.51)^{0.6615}} \right) \times 1424.31^{0.6615} = \$860{,}000{,}000$$

We follow this procedure for the other plant sizes and tabulate result as shown below. For the simulation, a distribution is assumed for the plant sizes. This distribution is based on the normal distribution.

Plant Size (t/d)	CAPEX ($ Billion)
1424	0.86
2374	1.20
3228	1.47
4748	1.90
7122	2.49
9495	3.00
14243	3.93

Table 3.10 CAPEX for MTO plant

3.2.2.4 Di-Methyl Ether (DME) Design

32.16 PJ of NG is required to produce 610 kt/a of DME (Seddon, 2004)

$$32.16PJ \equiv 30.49BCF$$

This implies that 30.49 BCF NG is required per annum to produce 610 kt/a of DME. By extension, 84,000,000 SCF/D is required to produce 1,671.23t/d of DME. We can now obtain the equivalent DME plant sizes for each F-T GTL plant size used in our model.

For 0.15 BCF/D, the equivalent DME plant is

$$\frac{1671.23 \times 0.15 \times 19^{9}}{84{,}000{,}000} = 3001$$

The results are shown in Table 3.11

F-T GTL bpd)	NG Feedstock BCF/D	DME Plant Size (t/d)
15000	0.15	3001
25000	0.25	5002
34000	0.34	6803
50000	0.50	10004
75000	0.75	15006
100000	1.00	20008
150000	1.50	30012

Table 3.11 DME Plant Sizes

Next, we obtain the cost streams for these plants using the economies of scale index of 0.6615 and Al-Saadoon's relations.

A 610 kt/a DME plant has a CAPEX of $360.17 MM, and an OPEX (excluding gas feedstock cost) that is 2.7% of the CAPEX. We shall use this figures as our baseline. FOB contract is assumed for the products.

Now to equation 3.13,

$$Cost = \left(\frac{BaseCost}{(BaseCapacity)^{Y}} \right) \times (Capacity)^{Y}$$

For a DME plant of 3001.21 t/d capacity;

$$Cost = \left(\frac{360.17 \times 10^{6}}{(1671.23)^{0.6615}} \right) \times 3001.21^{0.6615}\, t/d = \$530{,}517{,}682$$

We generate the other CAPEX and tabulate as shown in **Table 3.12.** For the simulation, a distribution is assumed for the plant sizes. This distribution is based on the *normal distribution*.

Plant Size (t/d)	Total CAPEX ($ Billion)
3001	0.53
5002	0.74
6803	0.91
10004	1.18
15006	1.54
20008	1.86
30012	2.43

Table 3.12 CAPEX for DME Plants

3.2.2.5 Crude Oil Refining Design

Pirog (2003) informs that a 150,000 bpd capacity crude oil refinery cost $2.5 billion. We use this as the baseline. We generate the CAPEX for other plant sizes According to Al-Saadoon's relations, and assume a distribution based on the normal distribution. The results are tabulated below.

Plant Size (bpd)	CAPEX ($ Billion)
15000	0.55
25000	0.76
34000	0.94
50,000	1.21
75000	1.58
100000	1.91
150000	2.50

Table 3.13 Crude Oil Refinery Sizes and CAPEX

Crude oil refineries have a gross profit margin of $12 to $16 per barrel (Abe DuPont, private communication; September 4 2006). I have elected to use $14/ barrel as the baseline and $10, $12, $16, and $18/barrel in the sensitivity analysis. FOB contract is assumed here as well.

3.2.2.6 Liquefied Natural Gas (LNG) Design

1 BCF NG = 0.021 MM (million) Ton of LNG (BP Statistical Review of World Energy June 2006). This implies that

$$\Rightarrow 0.15 BCF/D = 0.021 \times 0.15 \times 365 = 1.15 MMTPA$$

We can therefore, generate the equivalent LNG plant sizes (in terms of gas feedstock requirements)

According to Subero (2004), LNG requires a CAPEX of $476/TPA (Tons per annum); an OPEX of $0.58/MMBTU. While Chang (2001) quotes a shipping cost of $0.2/MMBTU/1000km. We shall adopt these figures for our model. LNG figures are usually quoted based on CIF contracts.

We shall apply Al-Saadoon's relations of economies of scale to both the OPEX and CAPEX.

LNG CAPEX

Using the 1.15 MMTPA as base capacity;

CAPEX for this LNG size = $476 \times 1.15 \times 10^6 = \$547{,}400{,}000$

Next we apply equation 3.13 using the index of 0.6615.

LNG OPEX

1000 BTU = 1 SCF

Also, 0.15 BCF/D NG is required for a 1.14975 MMTPA LNG

$$\Rightarrow 0.15 \times 10^9 \, SCF/D = 0.15 \times 10^{12} \, BTU/day = 0.15 \times 10^6 \, MMBTU/day$$
$$= 0.15 \times 11^6 \times 365 MMBTU/annum$$
$$= 54{,}750{,}000 MMBTU/annum$$

Annual OPEX (excluding feedstock cost) = $0.58 \times 54{,}750.000 = \$31{,}755{,}000$. Using this as the baseline, we can obtain the other OPEX using Al-Saadoon's relations. The results are tabulated in Table 3.14. We also assume a distribution based on the n*ormal distribution* for the plant sizes.

F-T GTL (bpd)	Plant Size (MMTPA)	Feedstock BCF/D	Annual MMBTU	CAPEX ($ Billion)	OPEX ($ Million)
15000	1.15	0.15	54750000	0.55	31.76
25000	1.92	0.25	91250000	0.77	44.52
34000	2.61	0.34	124100000	0.94	54.56
50000	3.83	0.50	182500000	1.21	70.42
75000	5.75	0.75	273750000	1.59	92.08
100000	7.67	1.00	365000000	1.92	111.39
150000	11.50	1.50	547500000	2.51	145.65

Table 3.14 CAPEX, OPEX and Plant Size for LNG

Shipping Cost

Shipping cost = $0.2/MMBTU/1000km (Chang, 2001).

3.2.2.7 Compressed Natural Gas (CNG) Design

The CAPEX of CNG, as provided by Subero (2004) is $1.08/MMBTU; while the OPEX is $0.33/MMBTU.

A 0.15 BCF/D NG contain 54,750,000 MMBTU. This implies that the CAPEX for a CNG facility that requires this feedstock is

$1.08 \times 54750000 = \$59{,}130{,}000$.

We use this as the baseline. We repeat the procedure to the OPEX (OPEX excludes the cost of gas feedstock). Next, we apply Al-Saadoon's equation of economies of scale. We tabulate the results as follows. The distribution based on the n*ormal distribution* is also assumed for the plant sizes.

F-T GTL (bpd)	Plant Size (BCF/A)	CAPEX ($ Million)	Operating Cost ($ Million)
15000	54.75	59.13	18.07
25000	91.25	82.90	25.33
34000	124.1	101.60	31.04
50000	182.5	131.13	40.07
75000	273.75	171.47	52.39
100000	365	207.41	63.37
150000	547.5	271.21	82.87

Table 3.15 CAPEX, Operating Cost and Plant Size for CNG

3.2.2.8 Pipelined Natural Gas (PNG) Design

The CAPEX for PNG is usually put in the $500,000 - $1MM/ mile range. I shall adopt Chang's (2001) use of $ 500,000/km as CAPEX; and Subero's (2004)

estimate of $0.69/ MMBTU as Operating cost. Economies of scale relations do not apply to PNG. This is because the costs are expressed per unit length of the pipeline. This suggests that long and short pipelines attract same unit cost.

I shall use two distances as baseline for my evaluation. These are 500km and 6482km. (GTS Design). The table for operating cost will be as shown below

Feedstock (BCF/Annum)	Annual MMBTU	Operating Cost ($ Million)
54.75	54750000	37.78
91.25	91250000	62.96
124.1	124100000	85.63
182.5	182500000	125.93
273.75	273750000	188.89
365	365000000	251.85
547.5	547500000	377.78

Table 3.16 Capacities and Operating Costs of PNG

3.2.2.9 Gas-to-Solids (GTS) Design

According to Kanda (2006), CAPEX for a 1MMTPA GTS plant (excluding shipping) is $3.2/MMBTU. Shipping cost is $1.5/MMBTU for a distance of 6482 km (3500nautical miles). Operating cost is $0.37/MMBTU (Chang, 2001).

The distribution based on the n*ormal distribution* is assumed for the simulation. Al-Saadoon's economies of scale relation is applicable for the Operating cost and CAPEX. The result is tabulated thus:

Plant Size (BCFA)	CAPEX ($ Billion)	Operating Cost ($ Million)	Shipping Cost ($ Million)	Annual MMBTU	Plant Size (MMTPA)
54.75	0.17	20.26	72.27	54750000	1.15
91.25	0.23	28.40	120.45	91250000	1.92
124.1	0.29	34.81	163.81	124100000	2.61
182.5	0.37	44.92	240.90	182500000	3.83
273.75	0.48	58.74	361.35	273750000	5.75
365	0.59	71.06	481.80	365000000	7.67
547.5	0.77	92.92	722.70	547500000	11.50

Table 3.17 CAPEX, Operating Costs and Sizes of GTS plants

3.2.2.10 Gas-to-Wire (GTW) Design

CAPEX is usually quoted to be about $1.0/W. (Chang, 2001; Northwest Power Planning Council, 2002). The operating cost is 5% of the CAPEX. We apply the distribution based on the *normal distribution*.

Now for the conversion relations;

One tonne of oil equivalent (TOE) = 12 MWh

$$1 billion Ft^3 NG = 0.026 \times 10^1$$
$$\Rightarrow 1 \times 10^9 Ft^3 NG = 26 \times 10^3 TOE = 12 \times 26 \times 10^3 MWh$$
$$= 312000\ MWh = 312\,GWh$$

$$\Rightarrow 0.15 BCF/D = 0.15 \times 365 BCF/annum$$
$$= 0.15 \times 365 \times 312 = 17{,}082 GWh = 17.082 TWh$$

This way, we obtain the equivalent GTS plants for every F-T GTL plant size. The result is tabulated below.

Annual MMBTU	CAPEX ($ Billion)	Plant sisze (MW-h)	Feedstock BCF
54750000	4.75	17082000	0.15
91250000	7.91	28470000	0.25
124100000	10.76	38719200	0.34
182500000	15.82	56940000	0.50
273750000	23.73	85410000	0.75
365000000	31.63	113880000	1.00
547500000	47.45	170820000	1.50

Table 3.18 Table 3.17 CAPEX and Sizes of GTW plants

3.2.3 The Monte Carlo Simulations

In this section, I shall identify the baseline simulations made and the parameters used for the sensitivity analyses. It should be noted that the choice of the parameters used in the sensitivity analyses are guided by value ranges reported in the literature.

3.2.3.1 Simulations for F-T GTL

Baseline parameters are

- Gas feedstock at $1/MMBTU
- Crude oil price at $50/barrel
- Profit margin of crude oil refinery at $14/barrel (the profit margin is added to the crude oil price to give the value of the crude oil products as well as F-T GTL products)
- Base capacity at 34,000 bpd

Sensitivity Parameter	1	2	3	4	5
Gas Cost ($/MMBTU)	0	5	10		
Crude Oil Price ($)	15	30	65	80	
Profit Margin ($/barrel)	10	12	16	18	
Base Capacity (x1000 bpd)	*15*	*25*	*75*	*100*	*150*

Table 3.19 F-T GTL Parameters for Sensitivity Analyses

This will be done for each of the six F-T GTL scenarios.

3.2.3.2 Simulations for Methanol Synthesis

Base parameters:

- Gas feedstock cost $1/MMBTU
- Product value is $150/ton

Sensitivity Parameter	1	2	3
Gas Cost ($/MMBTU)	0	5	10
Product Value ($/ton)	50	400	600

Table 3.19 Methanol Synthesis Parameters for Sensitivity Analyses

3.2.3.3 Simulations for MTO

- Gas feedstock cost $1/MMBTU
- Product value is $800/ton

Sensitivity Parameter	1	2	3
Gas Cost ($/MMBTU)	0	5	10
Product Value ($/ton)	400	600	1000

Table 3.21 MTO Parameters for Sensitivity Analyses

3.2.3.4 Simulations for DME

- Gas feedstock cost $1/MMBTU
- Product value is $150/ton

Sensitivity Parameter	1	2	3
Gas Cost ($/MMBTU)	0	5	10
Product Value ($/ton)	50	400	600

Table 3.22 DME Parameters for Sensitivity Analyses

3.2.3.5 Simulations for Crude Oil Refining

Base parameters:

- Profit margin is $14/barrel
- Crude oil cost is $50/barrel

Sensitivity Parameter	1	2	3	4
Crude oil Price ($/barrel)	15	30	65	80
Profit Margin ($/barrel)	10	12	16	18

Table 3.23 Refinery Parameters for Sensitivity Analyses

3.2.3.6 Simulations for LNG

Base parameters:

- Gas feedstock cost is $1/MMBTU
- Product Value is $7/MMBTU
- Shipping Cost is $0.2/MMBTU/1000Km
- Shipping Distances are 500Km and 6482Km

Sensitivity Parameter	1	2	3
Gas Cost ($/MMBTU)	0	1	5
Product Value ($/MMBTU)	5	10	-
Shipping Cost ($/MMBTU/1000Km)	0.1	1	-
Shipping Distance (Km)	2000	5000	8000

Table 3.24 LNG for Sensitivity Analyses

3.2.3.7 Simulations for CNG

Base parameters:

- Gas feedstock cost is $1/MMBTU
- Product Value is $7/MMBTU
- Shipping Cost is $0.54/MMBTU/1000Km
- Shipping Distances are 500Km and 6482Km

Sensitivity Parameter	1	2	3
Gas Cost ($/MMBTU)	0	1	5
Product Value ($/MMBTU)	5	10	-
Shipping Cost ($/MMBTU/1000Km)	0.1	1	-
Shipping Distance (Km)	2000	5000	8000

Table 3.25 CNG for Sensitivity Analyses

3.2.3.8 Simulations for PNG

- Gas feedstock cost is $1/MMBTU
- Product Value is $7/MMBTU
- CAPEX of $ 500,000 /Km
- Distances are 500Km and 6482Km

Sensitivity Parameter	1	2	3
Gas Cost ($/MMBTU)	0	1	5
Product Value ($/MMBTU)	5	10	-
CAPEX ($/1000Km)	200	1000	-
Distance (Km)	2000	5000	8000

Table 3.26 PNG for Sensitivity Analyses

3.2.3.9 Simulations for GTS

- Gas feedstock cost is $1/MMBTU
- Product Value is $7/MMBTU
- CAPEX of $ 3.2/MMBTU
- Shipping Distances are 500Km and 6482Km

Sensitivity Parameter	1	2	3
Gas Cost ($/MMBTU)	0	1	5
Product Value ($/MMBTU)	5	10	-
Shipping Cost ($/MMBTU/1000Km)	5	7	-
Shipping Distance (Km)	2000	5000	8000

Table 3.27 GTS for Sensitivity Analyses

3.2.3.10 Simulations for GTW

- Gas feedstock cost is $1/MMBTU
- CAPEX of $1/W
- Selling Price of Power $50/MW

Sensitivity Parameter	1	2	3
Gas Cost ($/MMBTU)	0	1	5
Product Value ($/MMBTU)	5	10	-
CAPEX ($/W)	0.5	2	5
Price of Power ($/MW)	30	80	160

Table 3.28 GTW for Sensitivity Analyses

CHAPTER FOUR

4 RESULTS

4.1 Results of Simulations

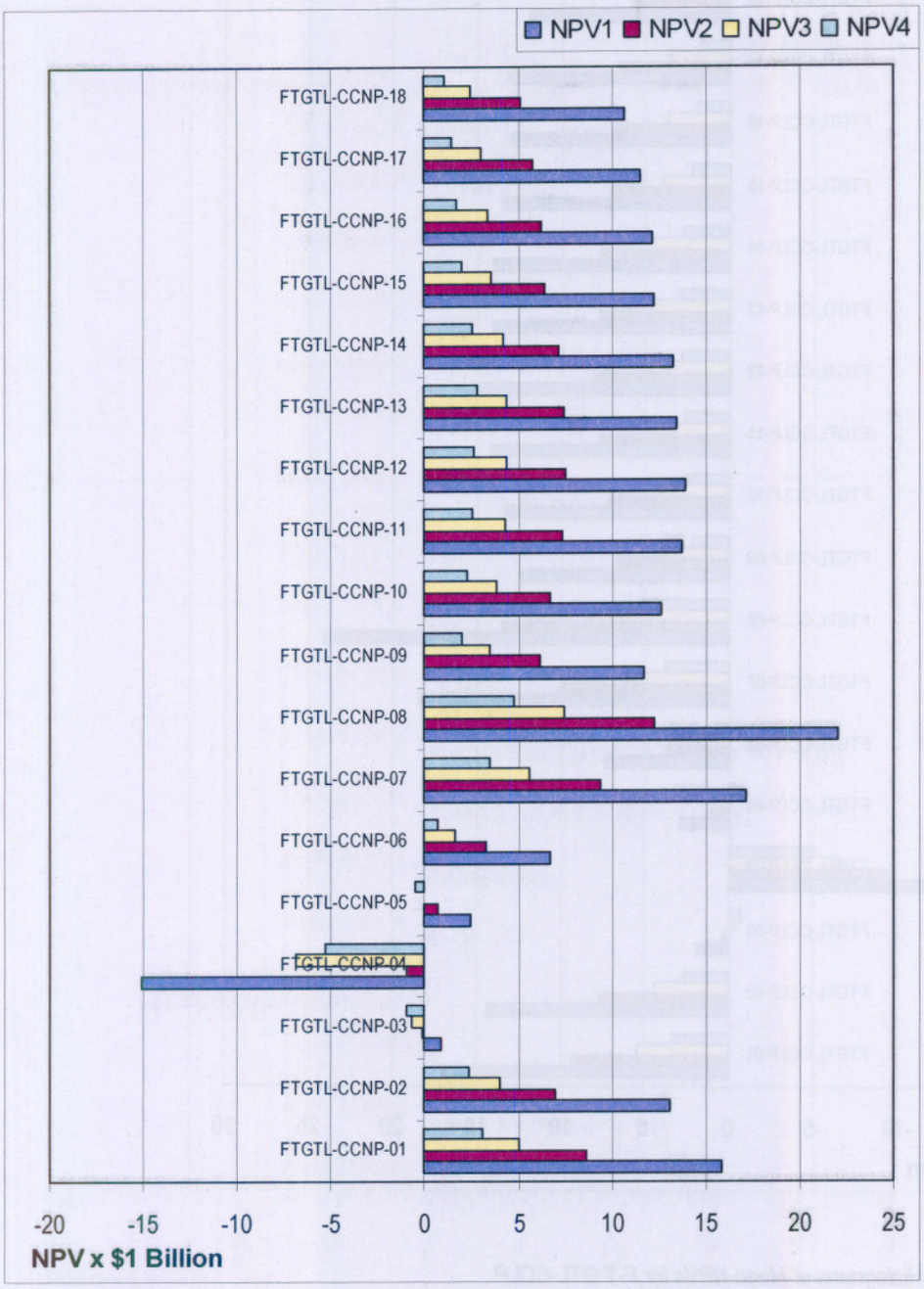

Figure 4.1 *Histograms of Mean NPVs for F-T GTL-CCNP*

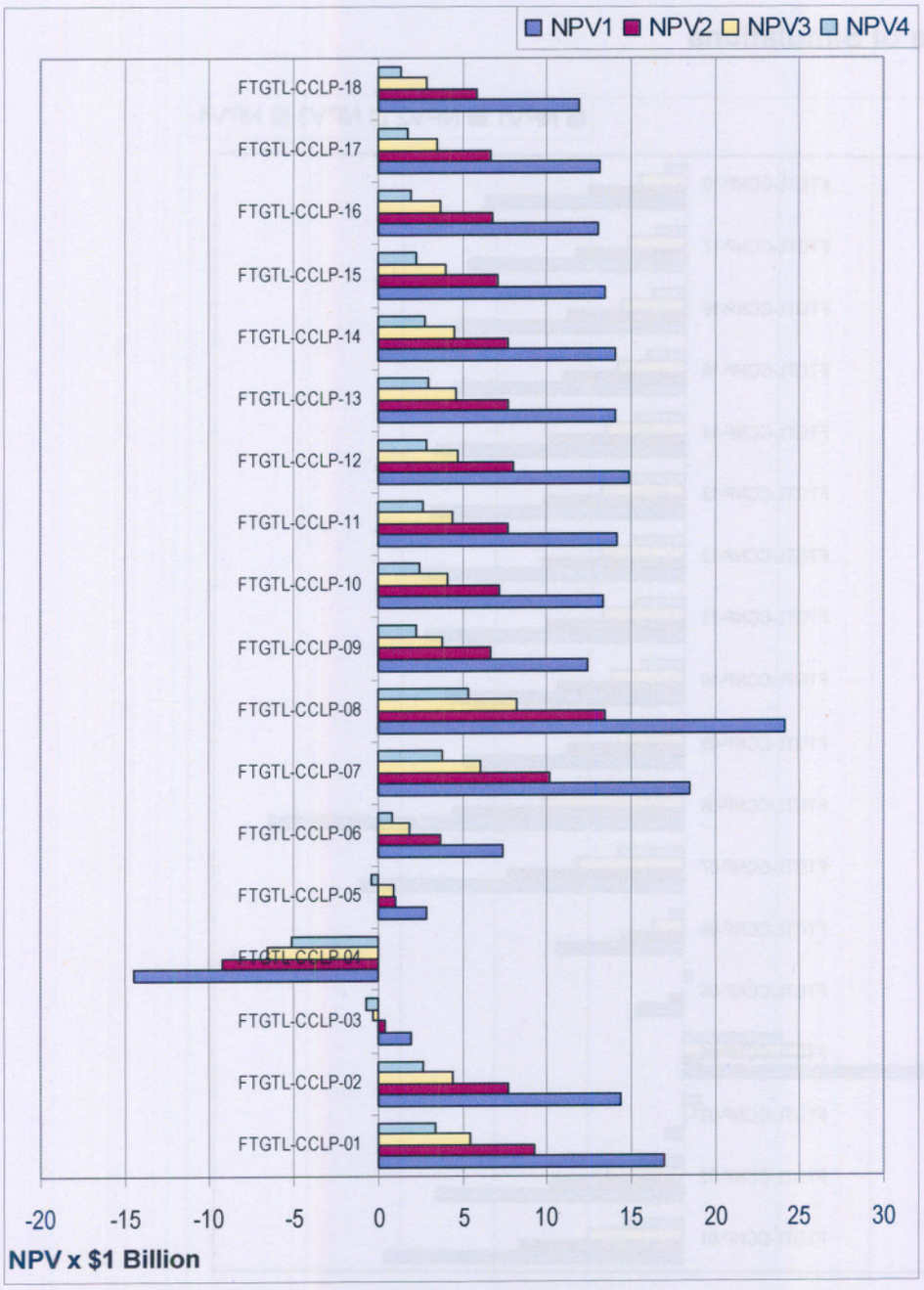

Figure 4.2 *Histograms of Mean NPVs for F-T GTL-CCLP*

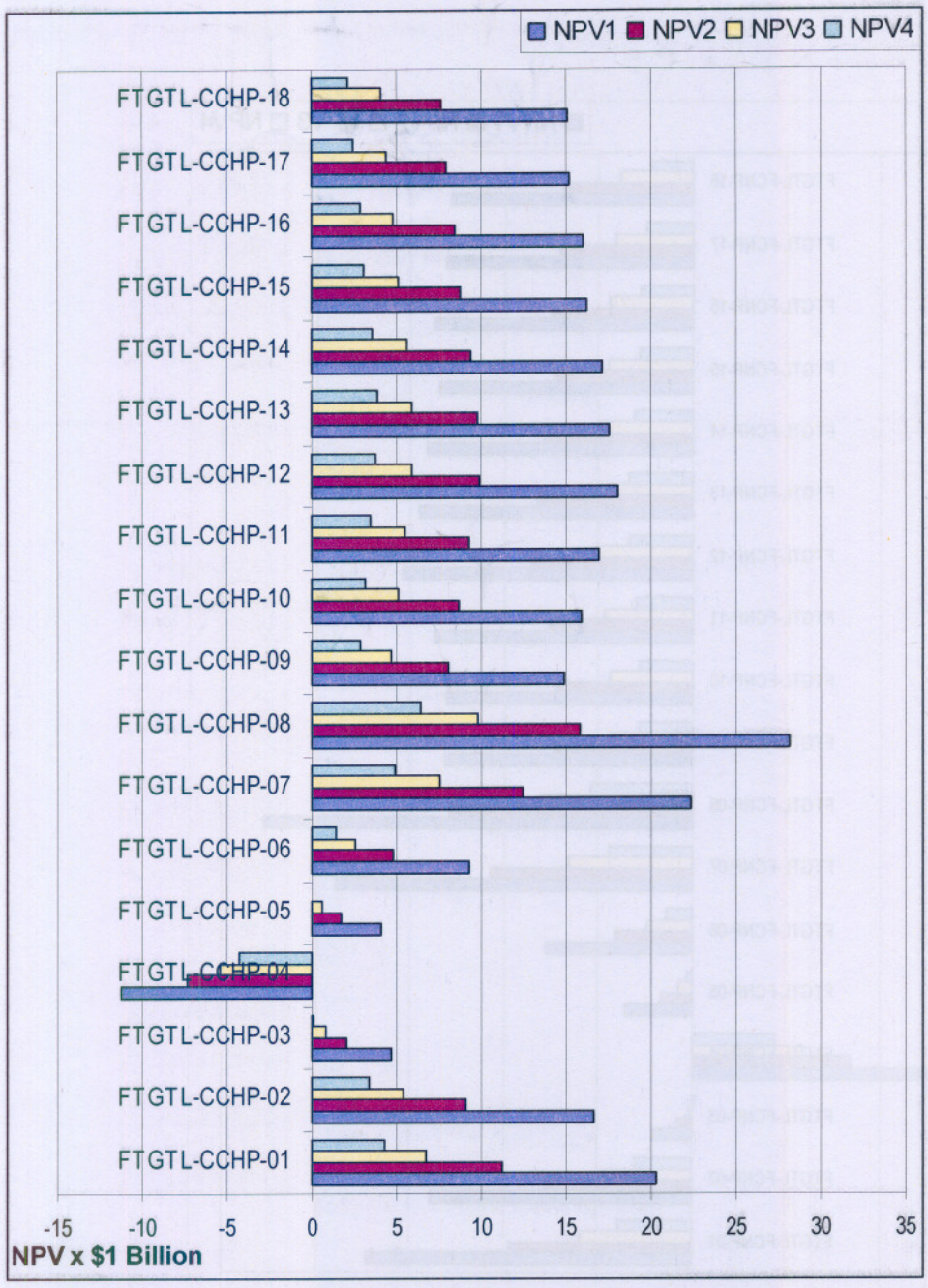

Figure 4.3 *Histograms of Mean NPVs for F-T GTL-CCHP*

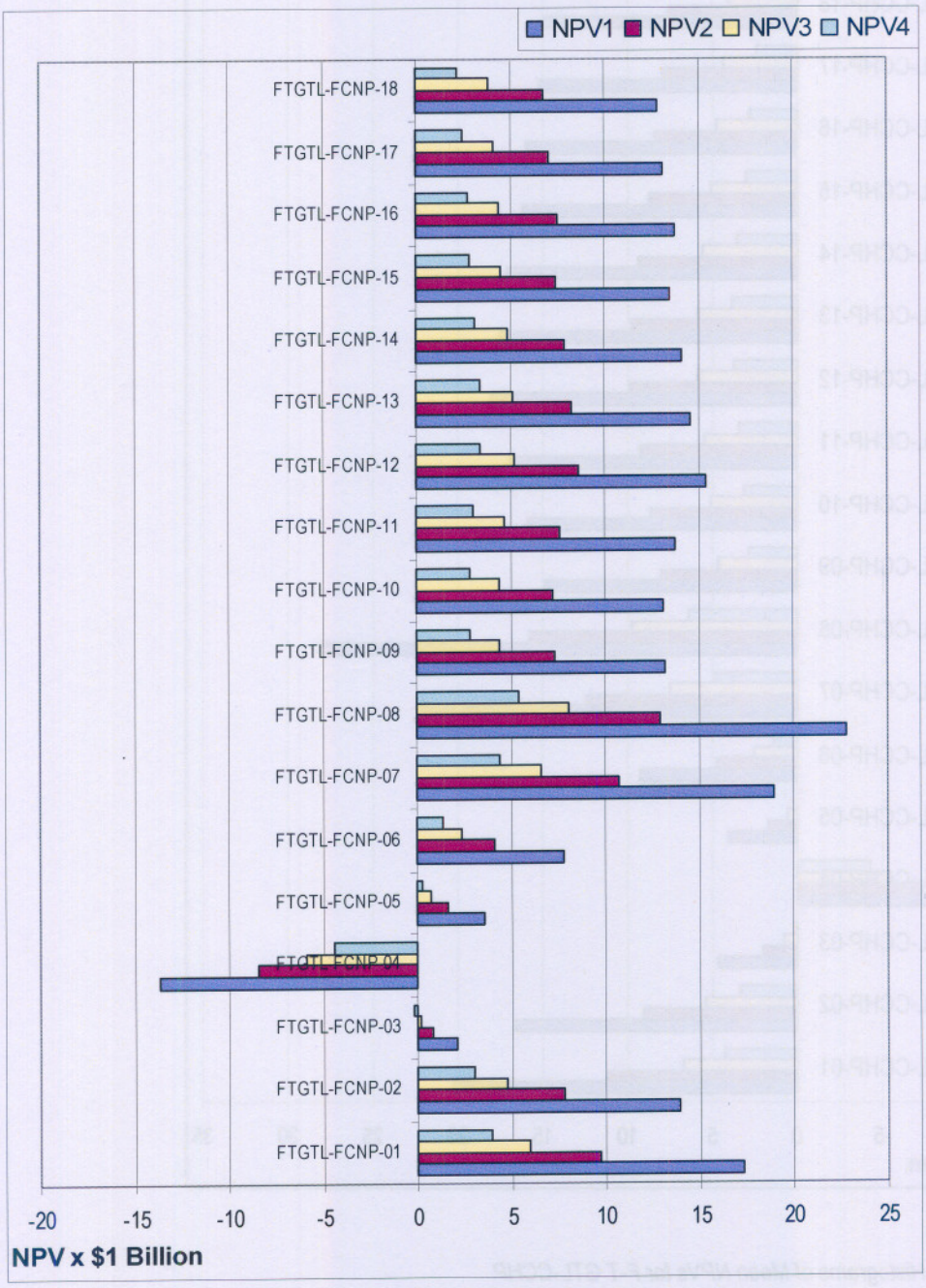

Figure 4.4 *Histograms of Mean NPVs for F-T GTL-FCNP*

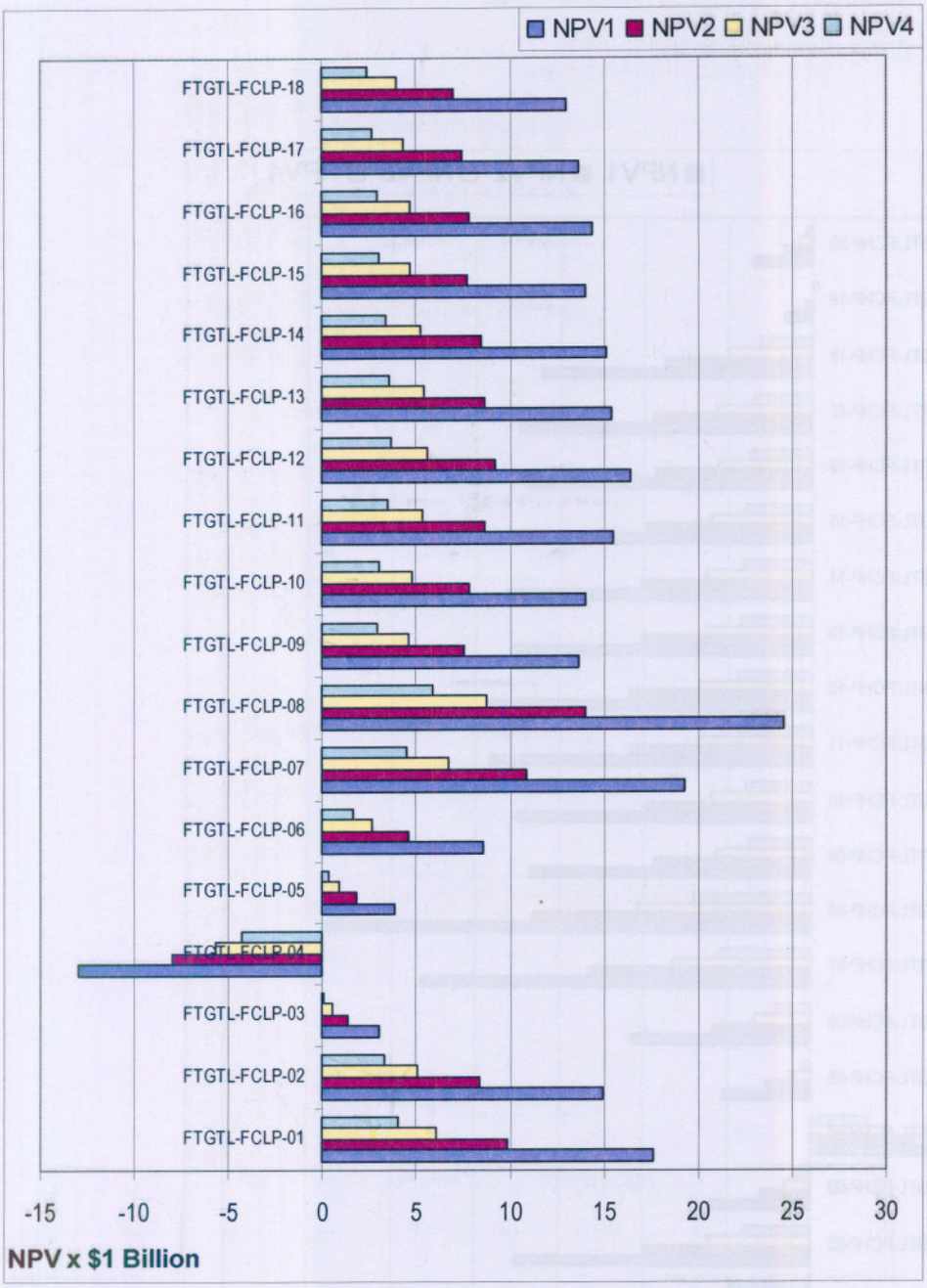

Figure 4.5 *Histograms of Mean NPVs for F-T GTL-FCLP*

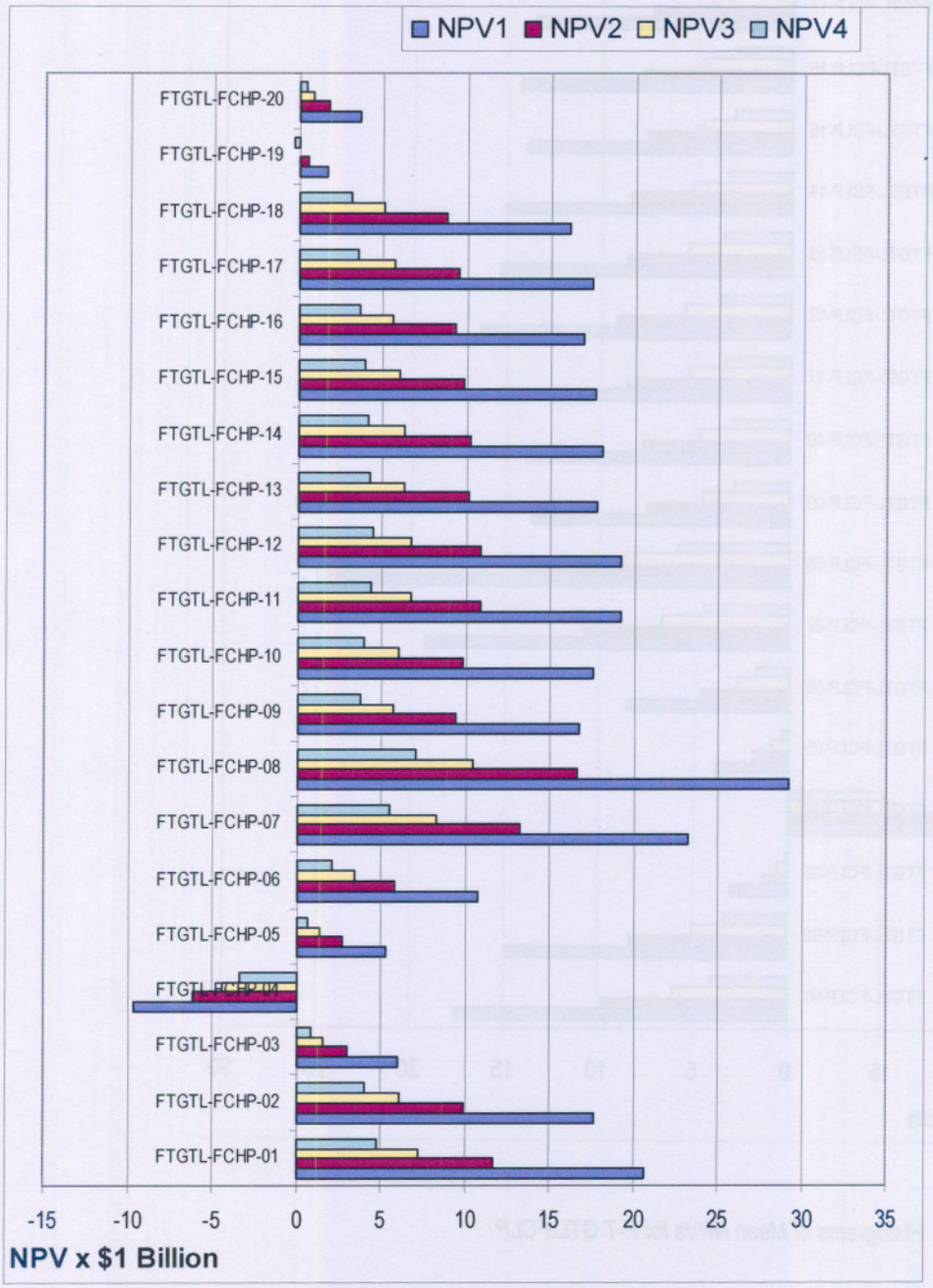

Figure 4.6 *Histograms of Mean NPVs for F-T GTL-FCHP*

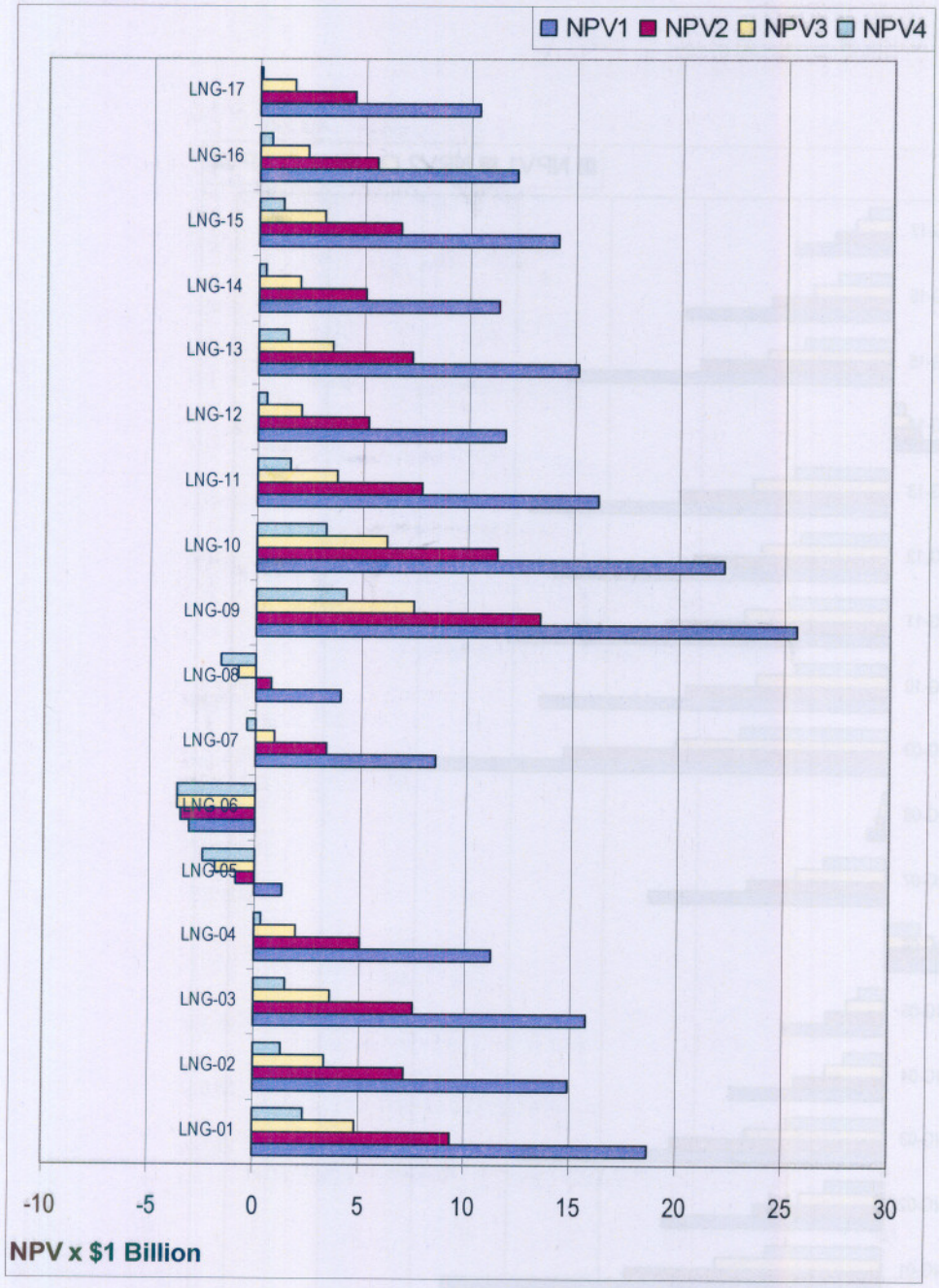

Figure 4.7 *Histograms of Mean NPVs for LNG*

Figure 4.8 *Histograms of Mean NPVs for CNG*

Figure 4.9 *Histograms of Mean NPVs for PNG*

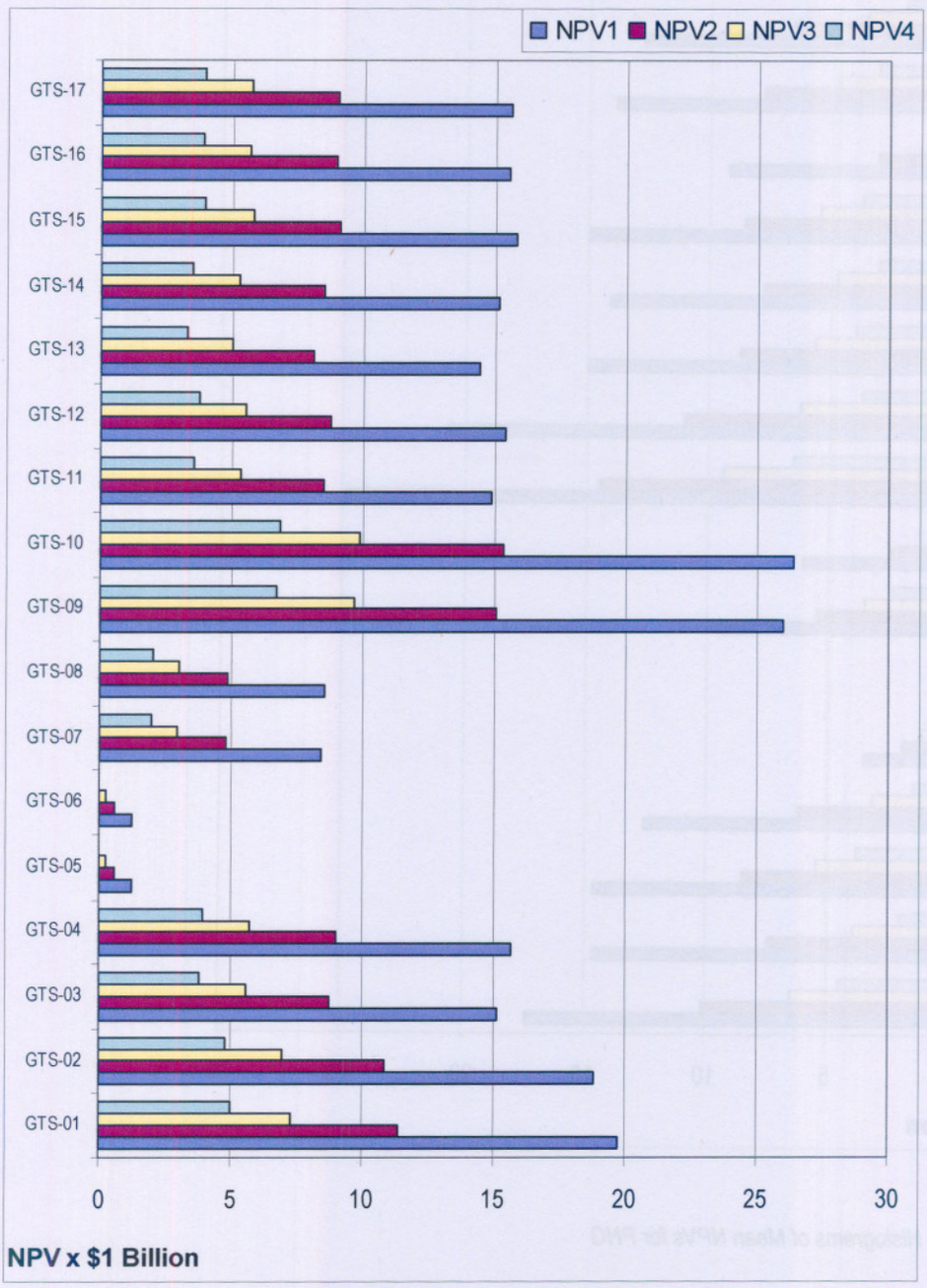

Figure 4.10 *Histograms of Mean NPVs for GTS*

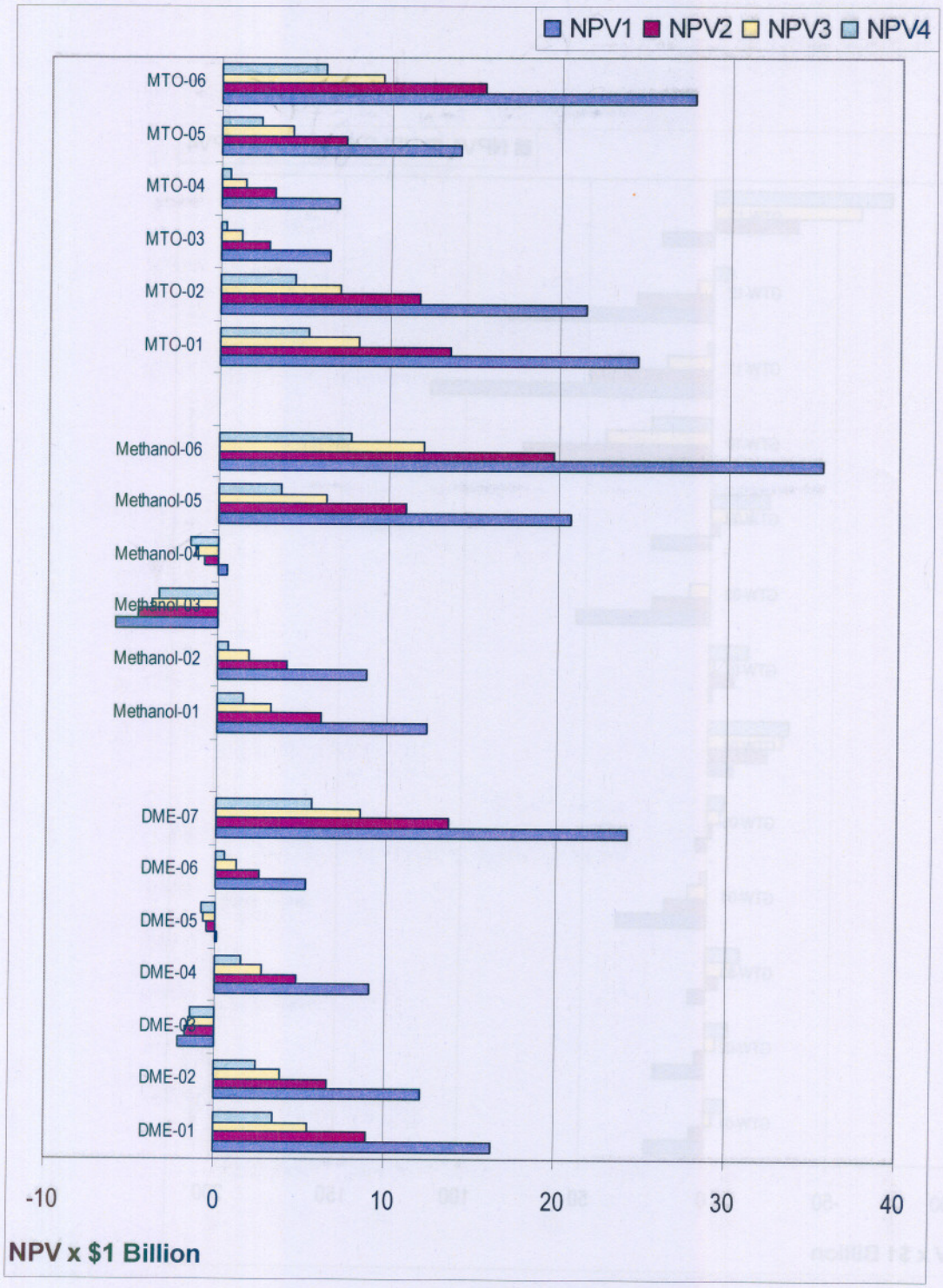

Figure 4.11 *Histograms of Mean NPVs for DME*

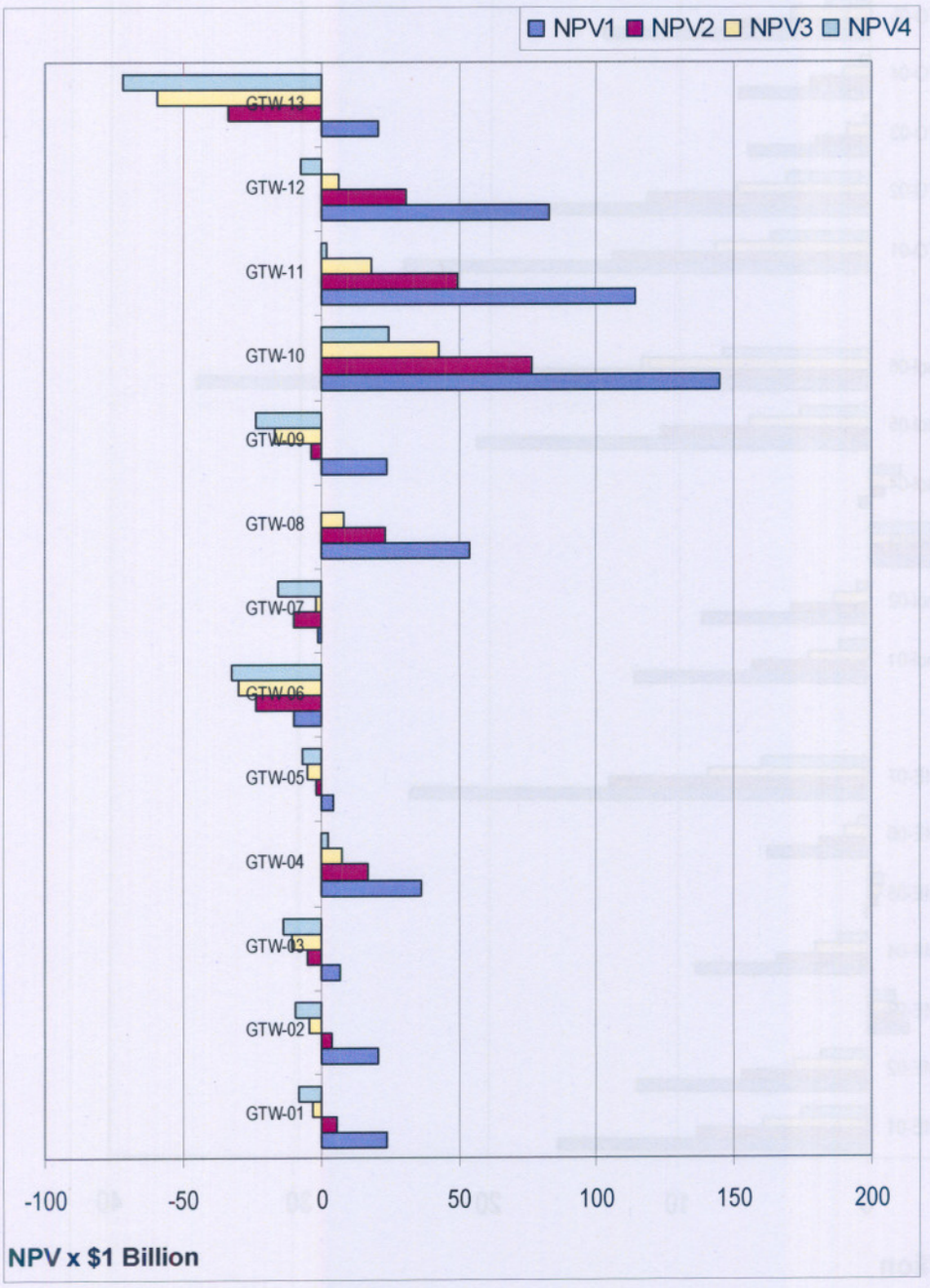

Figure 4.12 *Histograms of Mean NPVs for GTW*

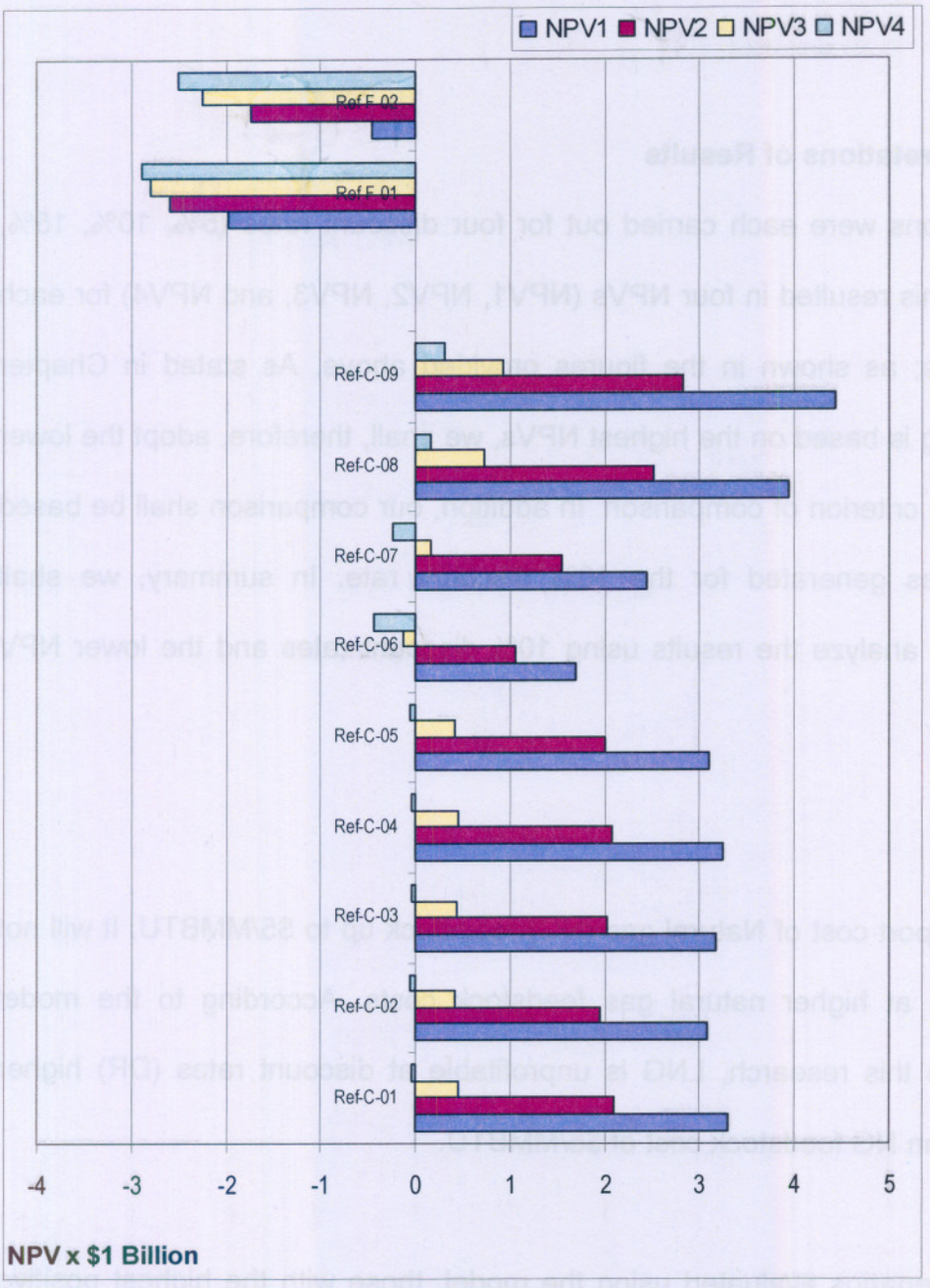

Figure 4.13 *Histograms of Mean NPVs for Crude oil Refining*

4.2 Interpretations of Results

The simulations were each carried out for four discount rates (5%, 10%, 15%, and 20%). This resulted in four NPVs (NPV1, NPV2, NPV3, and NPV4) for each set of results; as shown in the figures provided above. As stated in Chapter three, ranking is based on the highest NPVs, we shall, therefore, adopt the lower bound as the criterion of comparison. In addition, our comparison shall be based on the values generated for the 10% discount rate. In summary, we shall interpret and analyze the results using 10% discount rates and the lower NPV bounds.

4.2.1 LNG

LNG will support cost of Natural gas (NG) feedstock up to $5/MMBTU. It will not be profitable at higher natural gas feedstock costs. According to the model developed in this research, LNG is unprofitable at discount rates (DR) higher than 5% for an NG feedstock cost of $5/MMBTU.

Of all the scenarios evaluated using the model, those with the highest positive NPVs are those with a downstream price of gas at $10/MMBTU. These are closely followed by the scenarios with $0/MMBTU NG feedstock cost.

The scenarios which yielded negative NPVs are those with NG feedstock cost of $5/MMBTU (*LNG-05*, at 10%, 15%, & 20% DR and at a 500 km shipping distance; & *LNG-06* at a 6482 km shipping distance). Positive NPVs were

returned for *LNG-07* except at 20% DR. For *LNG-08*, NPVs were positive for 5% and 10%, and negative for 15% and 20% DR.

Using figures obtained at 10% DR as baseline, a 50% reduction in the shipping cost from baseline results in a 3%-7% increase in the NPV. A 50% reduction in NG feedstock cost results to a13%-25% increase in NPV; while a 50% increase in the price of final product results to an 85%-150% increase in NPV. This suggests that the NPV for LNG is most sensitive to changes in the market value of the final product; while it is least sensitive to the shipping cost.

The implication of these sensitivities is that slight changes in the final selling price of the gas will a significant effect on the viability of LNG, while changes in the shipping cost will need to be significant to have any noticeable effect.

According to the model, LNG will theoretically support shipping distances up to 18,500km. When the NPVs of baseline LNG, CNG, PNG, and GTS are compared (at NG cost of 1$/MMBTU, product price of 7$/MMBTU, and distance to market of 6482km); the results obtained were then plotted as shown in figure 4.14.

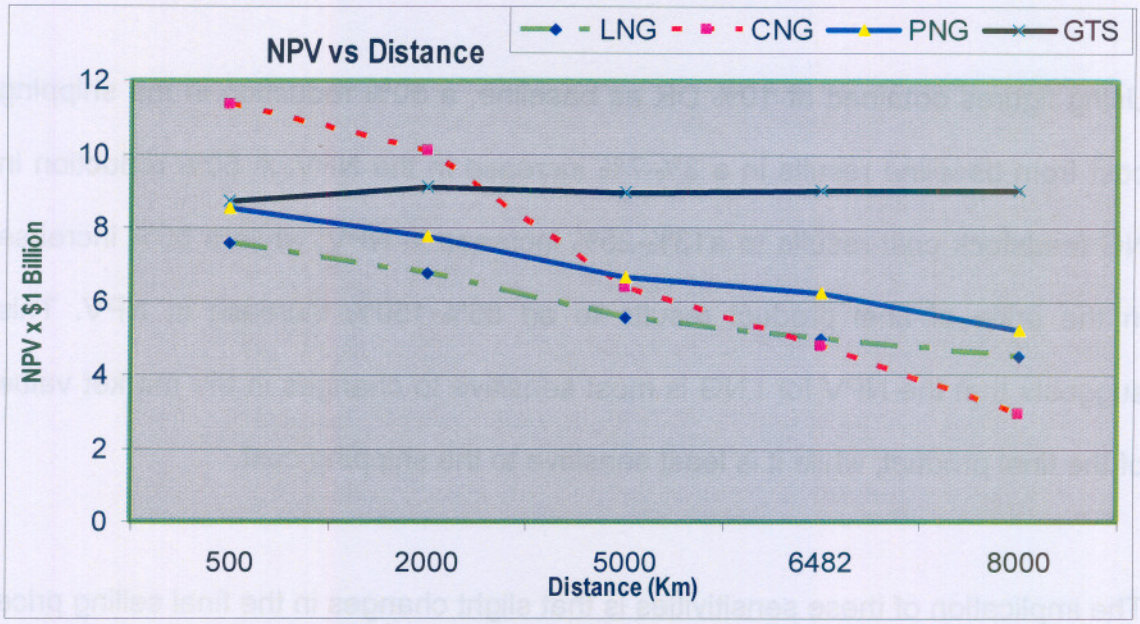

Figure 4.14 Scenario Comparisons for LNG, CNG, PNG and GTS

From figure 4.14, it is clear that CNG returned the highest NPVs at low distances and the least NPVs at high distances. PNG is consistently more viable than LNG over short and long distances. GTS maintains an almost horizontal profile at all the distances considered. It is consistently the most viable option except at very low distances, where CNG returns the highest values. LNG is the least viable of the four options at low distances; and it only becomes more viable than CNG at distances above 6500km.

4.2.2 CNG

CNG will not support NG feedstock cost above $5/MMBTU. As was the case with LNG, the scenarios for CNG with the highest NPVs are those with downstream gas prices of $10/MMBTU. These are closely followed by the scenarios with NG

feedstock cost of $0/MMBTU. CNG yielded negative NPVs with *CNG-14* and *CNG-06*.

Using figures obtained at 10% DR as baseline, a 50% reduction in the shipping cost from baseline results in a 12%-95% increase in the NPV. A 50% reduction in NG feedstock cost results to a 10%-25% increase in NPV; while a 50% increase in the price of final product results to a 78%-175% increase in NPV.

This suggests that the NPV for LNG is most sensitive to changes in the market value of the final product; while it is least sensitive to the cost of Natural gas feedstock. The percentage responsiveness of CNG to shipping cost appears to be more than that of LNG.

4.2.3 PNG

PNG will not support NG feedstock cost above $5/MMBTU. As was the case with LNG, and CNG, the scenarios for PNG with the highest NPVs are those with downstream gas prices of $10/MMBTU. These are closely followed by the scenarios with NG feedstock cost of $0/MMBTU. Negative NPVs are partially returned for some discount rates of *PNG-06*, *PNG-08*, and *PNG-14*. PNG can support a project with CAPEX as high as $1 million/Km provided the discount rate is less than 20% (provided the discount rate is 5%, 10%, or 15%).

Using figures obtained at 10% DR as baseline, a 50% increase in the CAPEX from baseline results in a 2%-50% decrease in the NPV. A 50% reduction in NG feedstock cost results to an 8%-12% increase in NPV; while a 50% increase in the price of final product results to a 55%-100% increase in NPV. The sensitivity to percentage change in the product is the greatest, and that to percentage change in cost of NG feedstock is least.

4.2.4 GTS

GTS, unlike LNG, CNG, and PNG, will support NG feedstock cost up to $5.3/MMBTU. As was the case with LNG, CNG, and PNG, the scenarios for GTS with the highest NPVs are those with downstream gas prices of $10/MMBTU. These are closely followed by the scenarios with NG feedstock cost of $0/MMBTU. No negative NPVs were obtained for the cases simulated for and presented. GTS, from the iterations made, is viable for any shipping distance.

Using figures obtained at 10% DR as baseline, a 50% decrease in the CAPEX from baseline results in a 2%-5% increase in the NPV. A 50% reduction in NG feedstock cost results to a 12%-16% increase in NPV; while a 50% increase in the price of final product results to a 80%-85% increase in NPV. The sensitivity to percentage change in the product is the greatest; and the sensitivity at to percentage change in CAPEX least.

4.2.5 GTW

GTW produced the most interesting results of all the options considered so far. It will support an NG feedstock cost up to $10/MMBTU (provided the discount rate is 5%). this price of NG is ten times the baseline. Meanwhile, by merely doubling the CAPEX from the baseline one obtains negative NPVs. This suggests that the viability of GTW is highly dependent on the CAPEX; while its sensitivity to NG cost is less pronounced.

Secondly, GTW is highly sensitive to the discount rates. It yielded negative NPVs for almost all cases of 20% discount rates considered. The highest NPVs obtained were at very high product (electric power) value.

In summary, GTW is really not affected by the source of the NG feedstock, since it is relatively insensitive to NG cost. However, the GTW facility must be sited where the CAPEX is as low as possible and where funds can be obtained cheaply.

4.2.6 DME

NG feedstock cost has to be less than $5/MMBTU for DME to be viable at the baseline product price. The upper limit is $3.5/MMBTU for a 10% discount rate. A 40% reduction in the market value of DME results in about 60% reduction in NPV; while a 40% reduction in the NG cost results in about 25% increase in the values of NPV. This suggests that sensitivity of DME to the market value is

higher than it is to the NG cost. DME will not be viable at market values less than $80/ton.

4.2.7 Methanol

As was the case for DME, methanol production is not viable at NG costs at $5/MMBTU or more. It will actually support NG costs up to $2.5/MMBTU at 10% discount rate. At lower rates, it can support a higher NG feedstock cost, and vise versa. A 67% increase in the market price of methanol results in an increase in NPV in excess of 160%; while a reduction in the cost of NG feedstock cost by 67% results in less than 40% increase in the value of the NPV.

4.2.8 MTO

MTO can support NG feedstock costs up to $6.5/MMBTU provided the discount rate is low enough. This value will reduce to $5.5/MMBTU at a 10% discount rate. It generally returns very high NPVs. This can be attributed to the high market value of olefins when converted to resins. All the cases considered in the simulation gave positive NPVs. 50% change in NG cost results in as low as 5% change in NPV; while 50% change in the market value of final products give a percentage change in NPV in excess of 259%.

4.2.9 Crude Oil Refining

Two broad cases were considered for refining: refining with respect to current and future cost estimates.

4.2.9.1 Future Crude Oil Refining

The future of refining is quite gloomy in the event that refiners are compelled by strict environmental regulations to invest on the modification of their refineries. Such investments are prohibitively high (in the region of $4-$13 billion).

This explains why after all possible parameters (within a reasonable range) were plugged into the model for the future refining; only negative NPVs were returned. This suggests that traditional crude oil refining will cease to be viable if refiners have to modify their plants to produce fuels that will meet future environmental requirements. These investments should therefore, be avoided as much as possible.

4.2.9.2 Current Crude oil Refining

Crude oil refining is generally sensitive to the discount rates. Almost all the cases considered yielded negative NPVs for cases of 20% discount rates. If the discounts rate is significantly less than 20%, crude oil will be viable even at profit margins as low as $14/barrel, and at crude oil prices as low as $15/barrel.

A 24.6% change in the profit margin results in a 40%-50% change in the NPVs for crude oil refining. In addition, the Absolute NPVs for crude oil refining are generally low.

4.2.10 F-T GTL

4.2.10.1 Current Cost, No Premium (CCNP)

This is the least viable of the six FT- GTL broad scenarios. In spite of this, it returned positive NPVs in all cases except two. It is not viable if crude oil sells for $15/barrel at $14/barrel profit margin for crude oil refining. This is because the F-T GTL products will have to be sold at $29/barrel, since no premium is charged. It should be pointed out here that the situation changes at higher profit margins and/or when premiums are charged on the products.

Secondly, this scenario could not support an NG feedstock cost of $10/MMBTU. It could however be marginally profitable at an NG feedstock cost of $5/MMBTU if the discount rate is as low as 5%.

If these two cases mentioned above are the only instances in which FT- GTL (CCNP) will not be profitable, it suggests that the other five scenarios will return even better NPV results, since F-T GTL (CCNP) is the least viable of the six. The NPVs for F-T GTL in general change by 10%-11% and by 15%-16% respectively for every 50% change in NG feedstock cost and crude oil profit margin.

4.2.10.2 Future Cost, High Premium (FCHP)

This is the most viable of all six F-T GTL broad scenarios. It is the most optimistic scenario considered for F-T GTL. In spite of this, it will only support a

$10/MMBTU NG feedstock cost if the price of crude oil is as high as $80/barrel at $14/barrel refining profit margin.

All the other F-T GTL scenarios fall within the range provided by *F-T GTL (CCNP)* and *F-T GTL (FCHP)*. This may be captured in a plot as shown below. In the plot, I present NPV generated at 10% discount rates. It is clear from the plot that there is a consistency in the relative NPVs of the six F-T GTL scenarios. *F-T GTL (CCNP)* consistently ranks lowest, while *F-T GTL (FCHP)* is consistently the most promising option; and others fall within these two bounds.

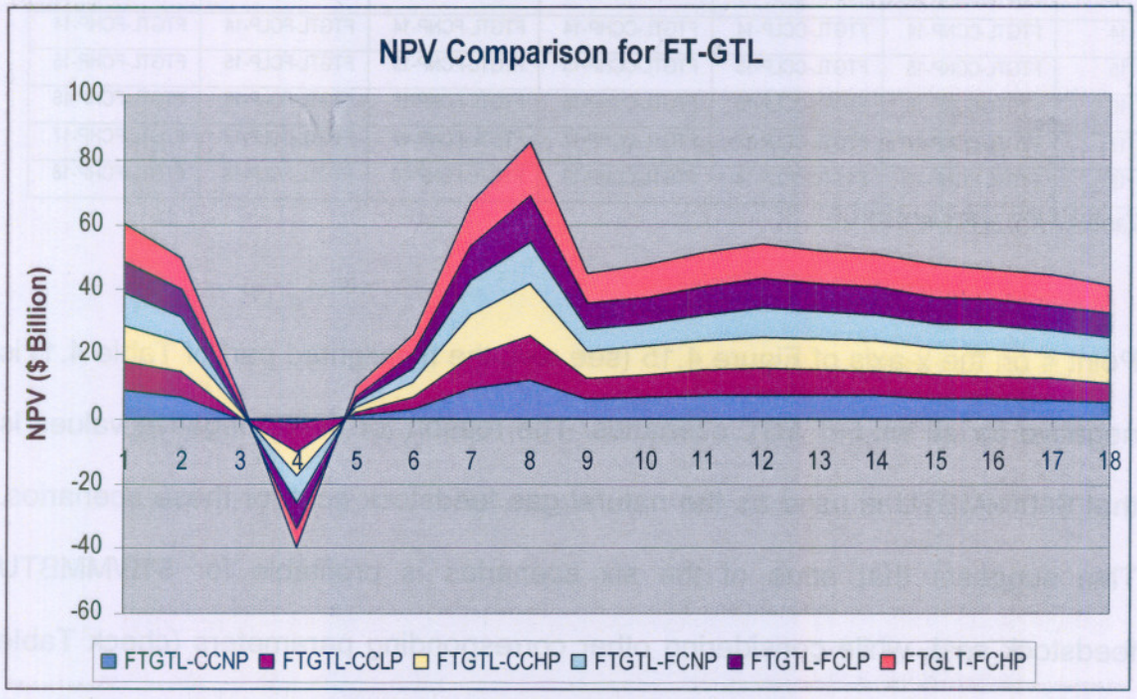

Figure 4.15 *NPV Comparison for the Six F-T GTL Base Scenarios*

The table below provides the F-T GTL scenario corresponding to each of the data points on the x-axis of Figure 4.15. The parameters of these scenarios are defined in appendix 4.

x-axis	FTGTL-CCNP	FTGTL-CCLP	FTGTL-CCHP	FTGTL-FCNP	FTGTL-FCLP	FTGTL-FCHP
1	FTGTL-CCNP-01	FTGTL-CCLP-01	FTGTL-CCHP-01	FTGTL-FCNP-01	FTGTL-FCLP-01	FTGTL-FCHP-01
2	FTGTL-CCNP-02	FTGTL-CCLP-02	FTGTL-CCHP-02	FTGTL-FCNP-02	FTGTL-FCLP-02	FTGTL-FCHP-02
3	FTGTL-CCNP-03	FTGTL-CCLP-03	FTGTL-CCHP-03	FTGTL-FCNP-03	FTGTL-FCLP-03	FTGTL-FCHP-03
4	FTGTL-CCNP-04	FTGTL-CCLP-04	FTGTL-CCHP-04	FTGTL-FCNP-04	FTGTL-FCLP-04	FTGTL-FCHP-04
5	FTGTL-CCNP-05	FTGTL-CCLP-05	FTGTL-CCHP-05	FTGTL-FCNP-05	FTGTL-FCLP-05	FTGTL-FCHP-05
6	FTGTL-CCNP-06	FTGTL-CCLP-06	FTGTL-CCHP-06	FTGTL-FCNP-06	FTGTL-FCLP-06	FTGTL-FCHP-06
7	FTGTL-CCNP-07	FTGTL-CCLP-07	FTGTL-CCHP-07	FTGTL-FCNP-07	FTGTL-FCLP-07	FTGTL-FCHP-07
8	FTGTL-CCNP-08	FTGTL-CCLP-08	FTGTL-CCHP-08	FTGTL-FCNP-08	FTGTL-FCLP-08	FTGTL-FCHP-08
9	FTGTL-CCNP-09	FTGTL-CCLP-09	FTGTL-CCHP-09	FTGTL-FCNP-09	FTGTL-FCLP-09	FTGTL-FCHP-09
10	FTGTL-CCNP-10	FTGTL-CCLP-10	FTGTL-CCHP-10	FTGTL-FCNP-10	FTGTL-FCLP-10	FTGTL-FCHP-10
11	FTGTL-CCNP-11	FTGTL-CCLP-11	FTGTL-CCHP-11	FTGTL-FCNP-11	FTGTL-FCLP-11	FTGTL-FCHP-11
12	FTGTL-CCNP-12	FTGTL-CCLP-12	FTGTL-CCHP-12	FTGTL-FCNP-12	FTGTL-FCLP-12	FTGTL-FCHP-12
13	FTGTL-CCNP-13	FTGTL-CCLP-13	FTGTL-CCHP-13	FTGTL-FCNP-13	FTGTL-FCLP-13	FTGTL-FCHP-13
14	FTGTL-CCNP-14	FTGTL-CCLP-14	FTGTL-CCHP-14	FTGTL-FCNP-14	FTGTL-FCLP-14	FTGTL-FCHP-14
15	FTGTL-CCNP-15	FTGTL-CCLP-15	FTGTL-CCHP-15	FTGTL-FCNP-15	FTGTL-FCLP-15	FTGTL-FCHP-15
16	FTGTL-CCNP-16	FTGTL-CCLP-16	FTGTL-CCHP-16	FTGTL-FCNP-16	FTGTL-FCLP-16	FTGTL-FCHP-16
17	FTGTL-CCNP-17	FTGTL-CCLP-17	FTGTL-CCHP-17	FTGTL-FCNP-17	FTGTL-FCLP-17	FTGTL-FCHP-17
18	FTGTL-CCNP-18	FTGTL-CCLP-18	FTGTL-CCHP-18	FTGTL-FCNP-18	FTGTL-FCLP-18	FTGTL-FCHP-18

Table 4.1 Key to Figure 4.15

Point 4 on the x-axis of Figure 4.15 (see also the highlighted part of Table 4.1) is negative for all six F-T GTL scenarios. The reason for these negative values is that $10/MMBTU is used as the natural gas feedstock cost for these scenarios. This suggests that none of the six scenarios is profitable for $10/MMBTU feedstock cost, while considering other corresponding parameters (check Table 4.2 and appendix 4 to see the values of the other parameters for these scenarios).

Option Number	NG Cost ($/MMBTU)	Product Value ($/barrel)	Crude oil price($/barrel)	Refinery Profit Margin ($/barrel)	Base capacity (bpd)
FTGTL-CCNP-04	10	64	50	14	34,000
FTGTL-CCLP-04	10	67.2	50	14	34,000
FTGTL-CCHP-04	10	76.8	50	14	34,000
FTGTL-FCNP-04	10	64	50	14	34,000
FTGTL-FCLP-04	10	67.2	50	14	34,000
FTGTL-FCHP-04	10	76.8	50	14	34,000

Table 4.2 Parameters for Point 4 on Figure 4.15

4.3 Comparison of the Base Cases

The NPVs obtained for the base cases at 10% is used in the ranking presented below. The values presented represent the lower bounds of the 95% confidence intervals of the mean NPVs, as discussed previously.

S/n	Option Baseline	NPV ($Billion) LB	NPV ($Billion) UB	Position (based on LB)
1	FTGTL-CCNP-02	6.99	7.6	12
2	FTGTL-CCLP-02	7.73	8.39	10
3	FTGTL-CCHP-02	9.06	9.84	4
4	FTGTL-FCNP-02	7.75	8.41	9
5	FTGTL-FCLP-02	8.34	9.08	8
6	FTGTL-FCHP-02	9.94	10.84	3
7	LNG-03	7.58	8.27	11
8	LNG-04	4.97	5.46	15
9	CNG-03	11.34	12.24	2
10	CNG-04	4.75	5.12	16
11	PNG-03	8.51	9.29	7
12	PNG-04	6.23	7.05	14
13	GTS-03	8.72	9.4	6
14	GTS-04	9.03	9.73	5
15	GTW-02	3.88	4.19	18
16	DME-02	6.62	6.8	13
17	Methanol-02	4.06	4.24	17
18	MTO-02	11.77	11.95	1
19	Ref-C-01	2.1	2.28	19
20	Ref-F-01	-2.59	-2.41	20

Table 4.3a Lower Bounds of The 95% Confidence Intervals of Mean NPV

NOTE

Some of the options have intervals that overlap. It may be more accurate to place such options on the same rank; as shown in Table 4.3b. However, for argument's sake we shall adopt the unique ranking outcome as derived from Table 4.3a.

Overlapping Options	Positions Shared
MTO-02, CNG-03	1
PNG-03, FTGTL-FCLP-02	7
FTGTL-FCNP-02, FTGTL-CCLP-02, FTGTL-FCLP-04	9
FTGTL-FCLP-13, FTGTL-FCLP-09	13

Table 4.3b Shared Ranking by Options with Overlapping Intervals

The values presented in Table 4.3a are plotted as histograms and presented below in Figure 4.16.

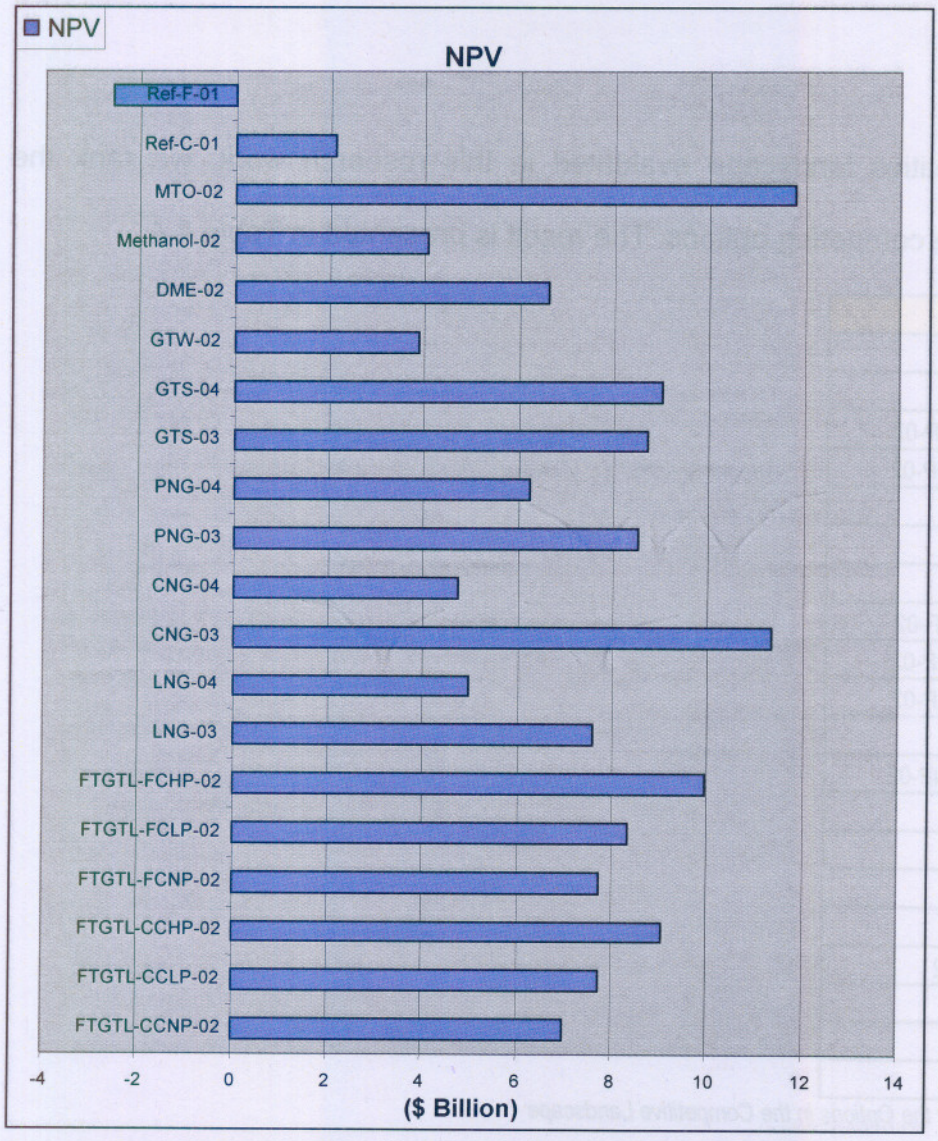

Figure 4.16 Baselines NPV of the Options in the Competitive Landscape

4.4 Ranking for the Competitive Landscape

As stated in Chapter three, a proposed project is economically viable if its NPV is positive. Meanwhile, in the case of mutually exclusive projects, the most viable is the one with the highest positive NPV. This way, it is possible to rank different projects based on their viabilities by simply ranking them based on their NPVs.

For the competitive landscape evaluated in this research work, we rank the baselines of the competing options. The result is presented in Table 4.4.

Rank	Option
1	MTO-02
2	CNG-03
3	FTGTL-FCHP-02
4	FTGTL-CCHP-02
5	GTS-04
6	GTS-03
7	PNG-03
8	FTGTL-FCLP-02
9	FTGTL-FCNP-02
10	FTGTL-CCLP-02
11	LNG-03
12	FTGTL-CCNP-02
13	DME-02
14	PNG-04
15	LNG-04
16	CNG-04
17	Methanol-02
18	GTW-02
19	Ref-C-01
20	Ref-F-01

Table 4.4 Ranking for the Options in the Competitive Landscape

4.5 Interpretation of Ranking

Let me start by pointing out that this is probably the first time a ranking as comprehensive as the one presented in Table 4.3a is being presented. In the next couple of paragraphs, I shall explain the implication of the positions taken by each of these options. I shall also motivate the limitation of this ranking.

From the ranking, it is obvious that the Ref-F-01 is ranked last. It yielded a negative NPV. This implies that it is not a profitable option. Ref-F-01 represents a possible scenario with crude oil refining. Since this scenario gives a negative

NPV, it should be avoided. This means that crude oil refiners should find alternatives before they are faced with the unfavourable situation promised by Ref-F-01. Ref-C-02 ranks as the second least profitable option. This is corroborated by literature in which crude oil refiners are reported to generally complain of lean returns.

MTO-02 tops the list. It clearly presents itself as the most profitable way of monetizing natural gas. The reason for this position is not far fetched. Resins made from olefins sell for as much as $800/ton. Natural gas monetized through this route fetches more returns per BTU than the other options.

There are, unfortunately, two problems with MTO. There are more natural gas reserves in the world than can be fully utilized by the MTO industry for use as resins. If the global gas reserves are to be turned into resins via MTO, the resins market will be saturated in little time. Secondly, monetizing natural gas through this route does not solve the crude oil refiner's current and future problems; neither does it solve any of the world's mounting energy problems.

Another angle to the MTO issue is that olefins can be converted to diesel. If this is done, MTO will drop to a much lower rank in Table 4.3a. This is because converting olefins to diesel would result in more production cost, while the value of product (value of resins to diesel) will drop significantly. It is therefore more

profitable to produce resins out of olefins than to convert the olefins to diesel. However, the problem of market saturation remains unsolved.

CNG-02 ranks second. This option corresponds to a shipping distance of 500km. The other CNG option (CNG-04) which corresponds to 6482km ranks sixteenth. CNG-02 will be the ideal natural gas monetization route for distances up to 500 km. However, for distances much higher than 500km, CNG ceases to be the best option. In reality, natural gas markets are usually as far as 5000km or more from the production areas. In cases where distances are in excess of 5000km, another gas monetization option would have to be found.

FTGTL-FCHP-02 and *FTGTL-CCHP-02* rank fourth and fifth respectively. *FTGTL-FCHP-02* would be a solution to the problem posed by long distances to CNG. Unfortunately *FTGTL-FCHP-02* is based on the assumption that current research efforts at reducing the CAPEX of F-T GTL significantly will be successful, and that it would be possible to charge a premium as high as 20% on F-T GTL products over crude oil products. In other words, *FTGTL-FCHP-02* is futuristic and uncertain.

On the other hand, *FTGTL-CCHP-02* is based on current cost regimes for F-T GTL. It is more realistic than *FTGTL-FCHP-02* even though they are both based on the assumption of 20% premium on the products. The fact that *FTGTL-CCHP-02* is based on current CAPEX makes it more realistic than *FTGTL-FCHP-02*.

Nevertheless, it might be too risky to base the decision to invest in F-TGTL on the expectation of a high premium. This is where this option is flawed.

GTS-04 and GTS-03 are the next most viable options. The GTS technology is, however, still speculative. It is possible that the published estimates for GTS are exaggerated. The final position of GTS in the competitive landscape will depend largely on how close the current data available on GTS will be to the data that will emerge when GTS becomes less speculative.

PNG-03 ranks seventh. This represents pipelined natural gas for distances up to 500km. It is inferior to CNG-03 which ranks third for the same distance. This implies that, although PNG-03 ranks quite high for short distances, it will be better to go the CNG way for such short distances. PNG-04, however, ranks higher than CNG-04 for longer distances (see Figure 4.14 & Table 4.4).

FTGTL-FCLP-02, *FTGTL-FCNP-02*, and *FTGTL-CCLP-02* are next in the ranking respectively. *FTGTL-FCLP-02* and *FTGTL-FCNP-02* are not dependable since they are based on future CAPEX, as discussed above. *FTGTL-CCLP-02*, unlike the previous two, is quite dependable. This is because it is based on current CAPEX and on a modest 5% premium.

As a result, if F-T GTL can command a 5% premium at current CAPEX, we are sure that F-T GTL is not only viable but is highly competitive. We can claim that

FTGTL-CCLP-02 ranks first (although it ranks tenth) in our competitive landscape for situations of large distances where CNG-03 and PNG-03 will fail. LNG-03 also fails for same reason as CNG-03 and PNG-03.

FTGTL-CCNP-02 ranks twelfth. It is even more realistic than *FTGTL-CCLP-02*. The former assumes no premium and is based on current cost. We can boldly claim that the true ranking for the competitive landscape starts with the twelfth rank. This is presented in Table 4.3a. The justification for this second ranking lies in the fact that distance to markets are usually very large in reality. Note that speculative GTS is excluded in this ranking for convenience.

Rank	Option
1	FTGTL-CCNP-02
2	DME-02
3	PNG-04
4	LNG-04
5	CNG-04
6	Methanol-02
7	GTW-02
8	Ref-C-01
9	Ref-F-01

Table 4.5 Selective Ranking of Options in the Competitive Landscape

According to this selective ranking, F-T GTL is the most viable option in the competitive landscape for distances to market that are significantly high. Most of the times, distances to market are large enough to support the ranking provided in Table 4.4. For the fewer instances where the distance to market is less than 1000km, the ranking based on Table 4.3a will be more appropriate.

4.6 Verification of Results

To verify the results obtained in this research work, I shall rely on the results presented in the literature by earlier authors. I shall identify areas of agreement and disparity of the results of my models with the results from other models as published.

Apanel (2005) concludes that "FT diesel production from stranded natural gas currently appears to be an economically attractive proposition if crude oil prices remain above $35/b and if the natural gas feed is available at a cost of $0.5/million Btu." Al-Saadoon (2005) also concludes that "with crude oil prices over $40/b, GTL products are a viable alternative to crude oil derived fuels." The model developed in this thesis assumed a crude oil price of $50/b as baseline and a gas feed cost of $1/MMBTU. The conclusion arrived at with these baselines was that F-T GTL is economically attractive.

Abdul-Rahman and Al-Maslamani (2004) conclude that GTL would be the preferred option in cases when PNG is not technically /economically feasible and/or when the gas reserves cannot support a world scale LNG plant. They conclude further that, in the absence of the scenario mentioned in the previous sentence, no clear economic preference can be made between LNG and GTL. They drew this second conclusion from their analysis which resulted in similar profitability for GTL and LNG.

In this thesis, LNG and F-T GTL gave similar profitability for *LNG-03* and *FTGTL-CCN-02*. This implies that the profitability of LNG was close to that of F-T GTL for situations when the shipping distance was 500km. *FTGTL-CCLP-02* is slightly more profitable than *CNG-03*. This is in agreement with Patel's (2005) conclusion that "GTL products exhibit slightly higher value per MMBTU than LNG."

The conclusion of Subero et al (2004), while comparing LNG, PNG and CNG, is that PNG delivers the highest NPV up to a distance of 500km (or 700km, depending on gas feedstock rate). CNG takes over from 500km (or 700km) till 1400km (or 1600km) before LNG turns out to be the most profitable. They conclude that PNG and CNG are suitable for short distances and LNG for longer distances. The results of my model indicate that both PNG and CNG are suitable for short distances; and that LNG as well as PNG is suitable for longer distances.

Chang (2001) compares CNG, GTS, GTL, GTW, LNG, and PNG for several scenarios. He concludes that CNG, GTS, and GTW ranked the highest followed by GTL; and that PNG and LNG are far behind the competition. The GTW that I adopted as the baseline ranks very low. CNG ranks high for 500km (CNG-03) and low for 6482km (CNG-04). The same applies for PNG. GTS and GTL ranks high generally; while LNG generally ranks low relative to the six options considered in this paragraph.

The *University of Houston Institute for Energy Law and Enterprise* (2003) concludes that LNG is cheaper than offshore PNG for distances more than 700 miles; and cheaper than onshore PNG for distances greater than 2,200 miles. Meanwhile, Cornot-Gandolphe et al (2003) conclude that for large deliveries (30 10^9 m^3/year), high pressure (HP) PNG is consistently much more profitable than LNG. LNG, however, becomes competitive with HP PNG at capacities below 10 10^9 m^3/year.

The comparison between LNG and PNG provided in this thesis (see figure 4.14) is consistent with the HP PNG versus LNG comparison for large gas deliveries provided by Cornot-Gandolphe et al.

Seddon (2004) concludes that MTO and methanol can support natural gas feedstock prices up to $3/MMBTU and $2.5/MMBTU respectively. He claims further that DME is viable at crude oil prices of $47/b. The base case DME presented in this research work is economically viable and compares favorably in the competitive landscape at crude oil baseline of $50/b.

From the model developed in this thesis, MTO can support natural gas feedstock prices up to $6.5/MMBTU at 5% discount rate; and up to $5.5/MMBTU at 10% discount rate; and up to lower NG prices at higher discount rates. Meanwhile, for methanol, my model returns $2.5 as the maximum limit of natural gas cost for

methanol to be profitable at 10% discount rate. These values, generally, are quite close to the values presented by Seddon.

In conclusion, I believe that the outcomes of the comparisons made between my results and the results existing in the literature sufficiently verify the results of my model. By extension, these comparisons, serve as a means of validating my model.

CHAPTER FIVE

5. CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

5.1.1 Introduction

I have been able to develop a model, via Monte Carlo simulations, which captures the entire gamut of the competitive landscape defined at the start of this research work. This model was developed in such a way that the parameters key to the economic evaluation of an option in the landscape can be varied at will.

This flexibility exhibited by the model allows the model to be useful even if the key parameters in reality change significantly from the baselines adopted. Furthermore, it is possible to use this model to investigate the outcomes of numerous scenarios with ease. These properties make my model unique.

5.1.2 The Competitive Landscape Model

As intended at the start of this research, my model incorporates both the upstream and downstream competitive scenarios faced by the F-T GTL technology. I have been able to develop a model that is more robust than other exiting models in the landscape which F-T GTL finds itself. In addition to its robustness, my model is real-time.

Many of the key parameters for the evaluation of the economic viability of the options in the competitive landscape vary frequently in real life. As a

consequence, conclusions reached on the relative viability of competing options based on an assumed scenario might be misleading if certain key parameters change later on. Many other existing models are designed in such a way that should these parameters change (and they would definitely change), the economic evaluation would have to be redone, usually from the beginning. This is time consuming and could be frustrating.

My real-time model, however, accommodates the possibility of parameter changes. In the event that a key parameter changes, all that has to be done is for the new figures to be plugged into the spreadsheet. And the appropriate NPVs are returned. The ranking could then be readjusted based on the new results. In addition, my model makes it possible for future scenario cases to be investigated with ease. There is no need to redevelop the model. All that is needed is for key parameters of interest to be plugged in to the model, for results to be regenerated instantly.

As promised, oil companies and gas-rich countries would, by using my model, be able to safely take investment decisions. The model assists with the investment decision to the extent that oil and gas companies as well as gas-rich countries will now know the situations when a specific option is the best. All they need to do now is to identify the key parameters specific to their own situation or to the scenario they want to investigate; plug the parameters into my model and see which of the options rank highest.

Governments will, in addition, be guided in taking legislative decisions for their energy sectors. Knowing the environmental friendliness of F-T GTL, and now its economic viability, governments can now safely make their emission requirements for fuels to be more stringent. This is because it is now possible to produce clean fuels economically.

The results obtained from the model for a specific country or company might be different from that obtained by others even if the model was implemented simultaneously. This difference in results is based on the difference in the scenarios that apply to individual companies and countries. This is another beauty of my real-time Monte Carlo model.

Many authors in their models generally take specific scenario cases and base their conclusions of the economic comparisons of the options on their static and rigid scenarios. This explains why in many cases, the conclusions of different authors, conflict. The conflict can be traced to the adoption of different scenarios. The flexibility inherent in my model allows it to eliminate the problems of conflicting conclusions. The model is based on similar assumptions.

In addition, other models are based on only segments of the competitive landscape. This compels prospective investors to adopt more than one model in evaluating the viability of a planned investment with respect to the entire

landscape of competition. They are now faced with the problem of making a single investment decision based on several models. The results from such evaluations are suspect for the reason that different assumptions and scenarios are applied in the development of the different models. My model eliminates this problem.

Finally, the results of the model have been compared with results provided by other authors. It is clear that the result of my model compares reasonably well with results from other models.

5.1.3 Ranking in the Competitive Landscape

It is difficult to produce an absolute ranking of the options in the competitive landscape. There are several reasons for this. The different utilization options require different feedstock. Some require crude oil as feedstock, others require natural gas. Secondly, the products have different markets governed by different forces. Thirdly, the key economic parameters vary with location, distance to market, technology adopted, and government policy. Rankings are scenario-specific.

The safe thing to do in situations like these is to adopt baselines that are as realistic as possible. This is what I have done in this thesis. To this end, my conclusion shall be with respect to the specific scenario that I have based my comparison on.

One major objective of this research work is to ascertain whether the current interests in F-T GTL will be sustained. Based on the various scenarios evaluated in the course of this project for F-T GTL, I conclude that F-T GTL is not only viable, it is highly competitive. In actual fact, F-T GTL outperforms many of the competing options in the landscape.

5.1.4 Other Conclusions

With my model, it is now possible to make investment decisions on F-T GTL with a global look at the entire competitive landscape. Governments and companies desiring to ascertain the relative viability of F-T GTL with respect to other options in the competitive landscape will no longer have to employ multiple models before taking their decisions. Since my model incorporates the competition upstream and downstream, it is like a one-stop model. Investment-seeking companies and countries can rest assured that decisions they make based on my model are based on the entire landscape and not limited to sections of the landscape.

F-T GTL will turn previously unmarketable natural gas reserves into products that will solve the problems of excessive transportation costs, long-term high-risk take-or-pay contracts associated with the traditional gas utilization options, a thing of the past. It will, in addition, be at the centre of the supply of cleaner fuels to meet the rising demand.

It is not far fetched to expect significant improvement in the exploration and exploitation technologies for unconventional natural gas reserves. These are an indication of the abundant opportunities ahead of F-T GTL.

No doubt, F-T GTL has come to stay.

5.2 Implications of the viability of F-T GTL

What are the implications of the viability of F-T GTL? The high rank enjoyed by F-T GTL does not necessarily imply that the other options should be scrapped. It rather implies that benefits of synergy can be exploited and enjoyed by combining two or more of the high-ranking options on a single site.

It should, however, be pointed out that the position of F-T GTL in the viability-ranking suggests that more of F-T GTL products will result in less of the products from the other options. This will result in a higher cost of the products from these other options. For instance, the market sustained by LNG will be affected by an increase in the production of F-T GTL negatively.

The viability of F-T GTL makes it attractive to many companies and countries. However, the high initial capital requirements guarantee that competition will be controlled. Only major energy companies will be able to meet the capital

requirements. The demand for natural gas should be expected to rise, while the cost too will rise in tandem.

There is a very good chance that gas flaring will stop with the emergence of F-T GTL. The attendant pollution will be eliminated and more income will then be generated for the company or country. We should expect a significant reduction in the need for the expensive gas re-injection.

5.3 Recommendations

Now that the viability of F-T GTL has been established beyond reasonable doubt and that it has been ascertained that the current interest in F-T GTL will be sustained for many decades to come; what next?

Should environmentalists succeed soon in enforcing their stringent clean-fuel requirements that threaten to drive crude oil refiners out of business, crude oil refiners now have a way out. Given the economic viability of F-T GTL, as well as the superiority in cleanliness exhibited by the F-T GTL fuels, crude oil refiners can take the route of crude oil gasification and then convert the gas to liquid fuels, the F-T GTL way. Alternatively, they could blend their products with those from F-T GTL since GTL products already surpass the requirements.

In the competitive landscape, it is difficult to have an option that is superior to other options for every possible scenario. As a result, the motive of gas-rich

countries and oil and gas companies should not be to decide which option is the overall best. The motive should rather be to diversify investment and risk. As a result, it might be wiser for countries and companies to identify the best two or three options from the landscape. They should then seek ways of synergizing these options.

For instance, LNG and F-T GTL facilities can be sited together. These two technologies have some infrastructure in common. Some of the by-products of F-T GTL form part of the inputs required to run LNG plants. If such a synergy is effected between LNG and F-T GTL, by the principle of the aggregation, the total CAPEX of such synergized plant will be less than the sum of the individual CAPEXs of LNG and F-T GTL if they are stand-alone plants. There is room for further research on this claim of the principle of aggregation working for synergized gas plants.

Another area of possible research is provided by the fact that by the time crude oil refining is finally tagged 'unprofitable', there has to be a use for whatever crude oil reserves that are left. One possible solution is the gasification of such crude oils and the subsequent routing of the resulting gas through the Fisher-Tropsch process to produce required fuels. The viability of this 'gas refinery' needs to be investigated.

In developing my model, I assumed a distribution based on the *normal distribution* spreadsheet for my distributions. Future researchers can develop similar models based on other probability distributions and then compare their results with mine. I expect that more realistic data will be available in the future to the benefit of the development of more accurate models.

In addition to the assumptions made in this work with respect to the nature of the distribution; the assumptions made concerning the exponent for economies of scale should be refined by other researchers as more dependable data become available in the future.

Most of the economic studies of F-T GTL and related technologies, including the baselines adopted in this thesis, rely heavily on low cost gas feedstock. We must be cautious here. This is because natural gas is a premium source of energy, because of the cleanliness of the products. There is, therefore, every reason to expect natural gas cost to rise in the near future. Current results which suggest that F-T GTL is viable might no longer be tenable in the future. Well, my model, as discussed earlier, will still be able to accommodate this future price of natural gas. The baselines will only have to be changed.

Although high gas costs were assumed for some of my scenario cases, It is still pertinent that more detailed studies be carried out to investigate the viability of F-T GTL in scenarios where natural gas cost is high. Future economic studies

should incorporate the possibility and effects of technological advancement on the viability of F-T GTL. Will significant increase in current process efficiencies of F-T GTL technologies be sufficient to make F-T GTL economically viable even when natural gas cost increase significantly? How significant should these improvements in process efficiencies be?

In conclusion, based on current econometrics, F-T GTL is unquestionably viable. It also has the potential to play a major role in solving many of the world's energy problems for decades to come. The F-T GTL is a technology that has been waiting to happen for close to a century. It is undeniably a worthy wait. Finally, *"will the current proliferation in interest in F-T GTL be sustained?"* My answer is: YES!

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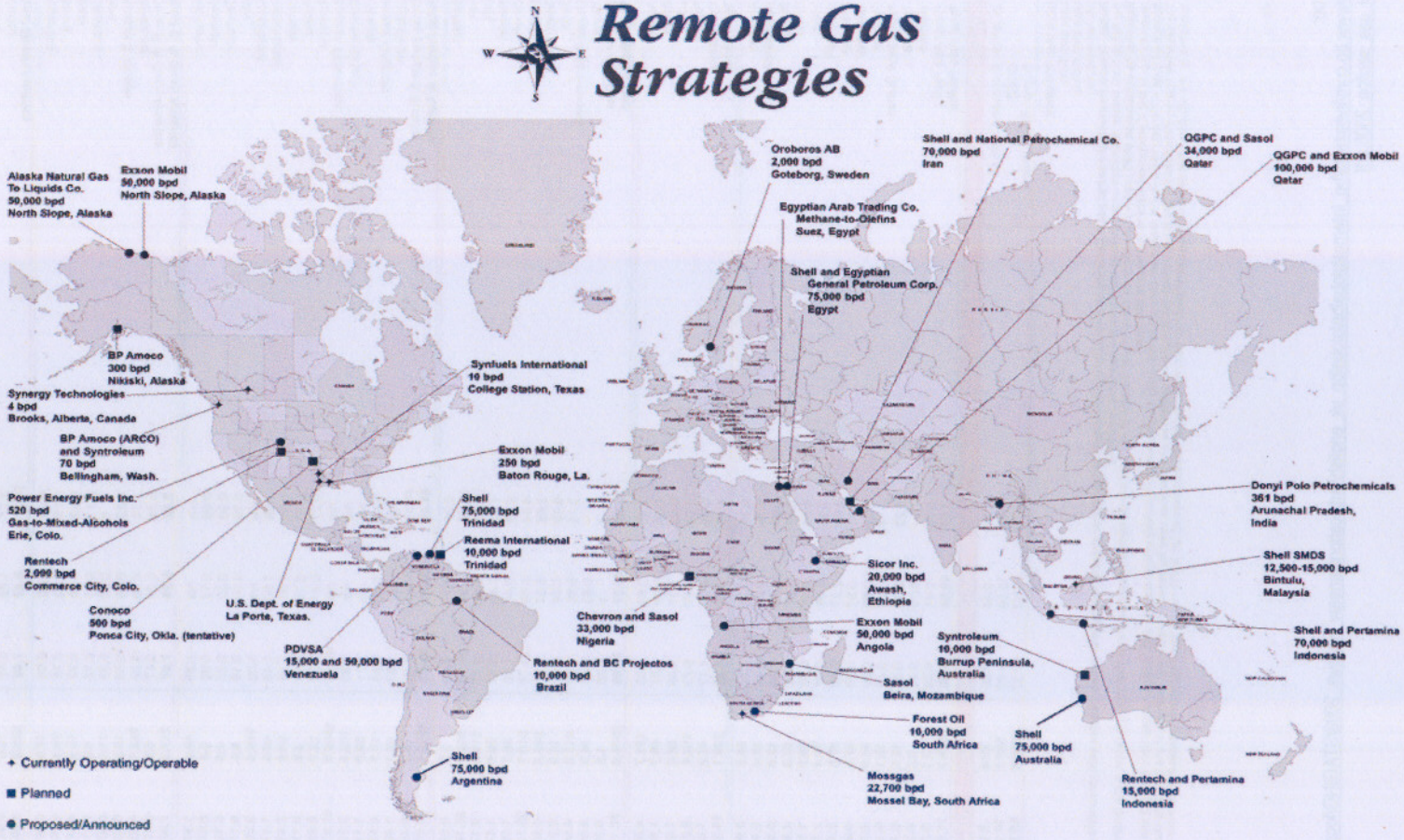
7.1 Appendix 1 Global Distribution of Proposed and Existing GTL Plants



Source: www.lngexpress.com

7.2 Appendix 2: Global Natural Gas Reserves

Natural gas

Proved reserves	At end 1985 Trillion cubic metres	At end 1995 Trillion cubic metres	At end 2004 Trillion cubic metres	At end 2005 Trillion cubic feet	Trillion cubic metres	Share of total	R/P ratio
USA	5.41	4.62	5.45	**192.5**	**5.45**	3.0%	10.4
Canada	2.78	1.93	1.59	**56.0**	**1.59**	0.9%	8.6
Mexico	2.17	1.92	0.42	**14.5**	**0.41**	0.2%	10.4
Total North America	**10.37**	**8.47**	**7.46**	**263.3**	**7.46**	**4.1%**	**9.9**
Argentina	0.68	0.62	0.55	**17.8**	**0.50**	0.3%	11.1
Bolivia	0.13	0.13	0.76	**26.1**	**0.74**	0.4%	71.1
Brazil	0.09	0.15	0.32	**10.8**	**0.31**	0.2%	27.3
Colombia	0.11	0.22	0.12	**4.0**	**0.11**	0.1%	16.7
Peru	†	0.20	0.33	**11.5**	**0.33**	0.2%	*
Trinidad & Tobago	0.32	0.35	0.53	**19.2**	**0.56**	0.3%	16.8
Venezuela	1.73	4.06	4.23	**152.3**	**4.32**	2.4%	*
Other S. & Cent. America	0.24	0.23	0.17	**5.9**	**0.17**	0.1%	87.7
Total S. & Cent. America	**3.32**	**5.96**	**7.07**	**247.8**	**7.02**	**3.9%**	**51.8**
Azerbaijan	n/a	n/a	1.37	**48.4**	**1.37**	0.8%	*
Denmark	0.09	0.12	0.08	**2.4**	**0.07**	*	6.5
Germany	0.30	0.22	0.20	**6.6**	**0.19**	0.1%	11.8
Italy	0.26	0.30	0.18	**5.9**	**0.17**	0.1%	14.0
Kazakhstan	n/a	n/a	3.00	**105.9**	**3.00**	1.7%	*
Netherlands	1.86	1.82	1.45	**49.6**	**1.41**	0.8%	22.3
Norway	0.57	1.81	2.39	**84.9**	**2.41**	1.3%	28.3
Poland	0.10	0.15	0.11	**3.8**	**0.11**	0.1%	25.3
Romania	0.27	0.41	0.30	**22.2**	**0.63**	0.3%	48.6
Russian Federation	n/a	n/a	47.80	**1688.0**	**47.82**	26.8%	80.0
Turkmenistan	n/a	n/a	2.90	**102.4**	**2.90**	1.6%	49.3
Ukraine	n/a	n/a	1.11	**39.0**	**1.11**	0.6%	56.7
United Kingdom	0.65	0.70	0.53	**18.7**	**0.53**	0.3%	6.0
Uzbekistan	n/a	n/a	1.86	**65.3**	**1.85**	1.0%	33.2
Other Europe & Eurasia	40.37	57.64	0.46	**16.2**	**0.46**	0.3%	47.0
Total Europe & Eurasia	**44.45**	**63.16**	**63.73**	**2259.4**	**64.01**	**35.6%**	**60.3**
Bahrain	0.21	0.15	0.09	**3.2**	**0.09**	0.1%	9.1
Iran	13.99	19.35	26.74	**943.9**	**26.74**	14.9%	*
Iraq	0.82	3.06	3.17	**111.9**	**3.17**	1.8%	*
Kuwait	1.04	1.49	1.57	**55.5**	**1.57**	0.9%	*
Oman	0.22	0.45	1.00	**35.1**	**1.00**	0.6%	56.9
Qatar	4.44	8.60	25.78	**910.1**	**25.78**	14.3%	*
Saudi Arabia	3.69	5.54	6.83	**243.6**	**6.90**	3.8%	99.3
Syria	0.12	0.24	0.31	**10.9**	**0.31**	0.2%	57.3
United Arab Emirates	3.15	5.86	6.06	**213.0**	**6.04**	3.4%	*
Yemen	–	0.43	0.48	**16.9**	**0.48**	0.3%	*
Other Middle East	†	†	0.05	**1.8**	**0.05**	*	26.7
Total Middle East	**27.67**	**45.37**	**72.09**	**2546.0**	**72.13**	**40.1%**	*
Algeria	3.35	3.89	4.55	**161.7**	**4.58**	2.5%	52.2
Egypt	0.26	0.65	1.87	**66.7**	**1.89**	1.1%	54.4
Libya	0.63	1.31	1.49	**52.6**	**1.49**	0.8%	*
Nigeria	1.34	3.47	5.23	**184.6**	**5.23**	2.9%	*
Other Africa	0.59	0.81	1.17	**42.2**	**1.20**	0.7%	*
Total Africa	**6.16**	**9.93**	**14.30**	**508.1**	**14.39**	**8.0%**	**88.3**
Australia	0.77	1.28	2.52	**89.0**	**2.52**	1.4%	67.9
Bangladesh	0.35	0.27	0.44	**15.4**	**0.44**	0.2%	30.7
Brunei	0.24	0.40	0.34	**12.0**	**0.34**	0.2%	28.3
China	0.87	1.67	2.20	**83.0**	**2.35**	1.3%	47.0
India	0.46	0.68	0.92	**38.9**	**1.10**	0.6%	36.2
Indonesia	1.98	1.95	2.77	**97.4**	**2.76**	1.5%	36.3
Malaysia	1.49	2.27	2.46	**87.5**	**2.48**	1.4%	41.4
Myanmar	0.27	0.27	0.50	**17.7**	**0.50**	0.3%	38.5
Pakistan	0.62	0.60	0.80	**34.0**	**0.96**	0.5%	32.2
Papua New Guinea	†	0.43	0.43	**15.1**	**0.43**	0.2%	*
Thailand	0.22	0.16	0.35	**12.5**	**0.35**	0.2%	16.5
Vietnam	–	0.15	0.24	**8.3**	**0.24**	0.1%	45.6
Other Asia Pacific	0.25	0.41	0.39	**13.1**	**0.37**	0.2%	34.7
Total Asia Pacific	**7.57**	**10.54**	**14.35**	**523.7**	**14.84**	**8.3%**	**41.2**
TOTAL WORLD	99.54	143.42	179.00	**6348.1**	**179.83**	**100.0%**	**65.1**
of which: European Union 25	3.49	3.44	2.66	**90.8**	**2.57**	1.4%	12.9
OECD	15.36	15.09	15.02	**527.7**	**14.95**	8.3%	13.8
Former Soviet Union	40.00	57.37	58.32	**2058.8**	**58.32**	32.4%	78.7

*More than 100 years.
†Less than 0.05.
*Less than 0.05%.
n/a not available.

Notes: Proved reserves of natural gas – Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions.
Reserves-to-production (R/P) ratio – If the reserves remaining at the end of any year are divided by the production in that year, the result is the length of time that those remaining reserves would last if production were to continue at that level.
Source of data – The estimates in this table have been compiled using a combination of primary official sources and third-party data from Cedigaz and the OPEC Secretariat. The reserves figures shown do not necessarily meet the definitions, guidelines and practices used for determining proved reserves at the company level, for instance, those published by the US Securities and Exchange Commission or recommended for the purposes of UK SORP nor do they necessarily represent BP's view of proved reserves by country.

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Source:
http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/publications/energy_reviews_2006/STAGING/local_assets/downloads/pdf/natural_gas_section_2006.pdf

7.3 Appendix 3: NPVs Obtained from Simulations

Option No.	NPV1 (Mean)	NPV2 (Mean)	NPV3 (Mean)	NPV4 (Mean)	NPV1 (Lower Bound)	NPV2 (Lower Bound)	NPV3 (Lower Bound)	NPV4 (Lower Bound)	NPV1 (Upper Bound)	NPV2 (Upper Bound)	NPV3 (Upper Bound)	NPV4 (Upper Bound)
FTGTL-CCNP-01	**16.53**	**9.00**	**5.30**	**3.27**	**15.83**	**8.62**	**5.08**	**3.13**	**17.23**	**9.38**	**5.53**	**3.41**
FTGTL-CCNP-02	13.65	7.29	4.18	2.48	13.09	6.99	4.01	2.38	14.21	7.60	4.35	2.58
FTGTL-CCNP-03	**0.91**	**-0.15**	**-0.64**	**-0.89**	**0.87**	**-0.16**	**-0.67**	**-0.93**	**0.95**	**-0.13**	**-0.61**	**-0.85**
FTGTL-CCNP-04	-14.52	-9.22	-6.56	-5.06	-15.12	-0.96	-6.84	-5.27	-13.91	-8.83	-6.29	-4.85
FTGTL-CCNP-05	**-2.54**	**0.77**	**-0.07**	**-0.52**	**2.44**	**0.74**	**-0.08**	**-0.54**	**2.64**	**0.80**	**-0.06**	**-0.49**
FTGTL-CCNP-06	7.02	3.43	1.68	0.73	6.72	3.28	1.61	0.70	7.31	3.57	1.75	0.77
FTGTL-CCNP-07	**17.94**	**9.83**	**5.85**	**3.66**	**17.17**	**9.41**	**5.60**	**3.51**	**18.72**	**10.26**	**6.10**	**3.82**
FTGTL-CCNP-08	23.03	12.81	7.78	5.01	22.07	12.27	7.45	4.80	24.00	13.34	8.10	5.21
FTGTL-CCNP-09	**12.20**	**6.45**	**3.64**	**2.10**	**11.68**	**6.18**	**3.49**	**2.01**	**12.71**	**6.72**	**3.79**	**2.19**
FTGTL-CCNP-10	13.14	6.99	3.97	2.33	12.59	6.69	3.81	2.23	13.70	7.28	4.14	2.42
FTGTL-CCNP-11	**14.37**	**7.71**	**4.45**	**2.66**	**13.77**	**7.39**	**4.26**	**2.55**	**14.96**	**8.03**	**4.63**	**2.77**
FTGTL-CCNP-12	14.53	7.83	4.54	2.74	13.91	7.49	4.35	2.63	15.16	8.16	4.74	2.86
FTGTL-CCNP-13	**14.10**	**7.74**	**4.62**	**2.91**	**13.49**	**7.41**	**4.43**	**2.79**	**14.70**	**8.08**	**4.82**	**3.03**
FTGTL-CCNP-14	13.88	7.50	4.38	2.66	13.30	7.19	4.20	2.55	14.45	7.81	4.56	2.77
FTGTL-CCNP-15	**12.81**	**6.72**	**3.75**	**2.12**	**12.26**	**6.43**	**3.58**	**2.03**	**13.35**	**7.00**	**3.91**	**2.21**
FTGTL-CCNP-16	12.68	6.50	3.48	1.84	12.14	6.22	3.34	1.76	13.22	6.77	3.63	1.92
FTGTL-CCNP-17	**11.98**	**6.01**	**3.10**	**1.52**	**11.48**	**5.76**	**2.97**	**1.46**	**12.47**	**6.25**	**3.22**	**1.58**
FTGTL-CCNP-18	11.16	5.39	2.59	1.07	10.68	5.16	2.48	1.03	11.64	5.62	2.70	1.12
FTGTL-CCLP-01	**17.71**	**9.68**	**5.74**	**3.58**	**16.97**	**9.28**	**5.50**	**3.43**	**18.45**	**10.09**	**5.98**	**3.73**
FTGTL-CCLP-02	14.98	8.06	4.67	2.81	14.37	7.73	4.48	2.70	15.59	8.39	4.87	2.92
FTGTL-CCLP-03	**2.02**	**0.45**	**-0.29**	**-0.68**	**1.94**	**0.43**	**-0.31**	**-0.71**	**2.11**	**0.47**	**-0.27**	**-0.65**
FTGTL-CCLP-04	-13.87	-8.85	-6.34	-4.91	-14.44	-9.21	-6.60	-5.12	-13.30	-8.49	-6.08	-4.71
FTGTL-CCLP-05	**2.99**	**1.04**	**0.11**	**-0.39**	**2.87**	**1.00**	**0.99**	**-0.41**	**3.12**	**1.09**	**0.12**	**-0.37**
FTGTL-CCLP-06	7.76	3.86	1.96	0.93	7.43	3.70	1.88	0.89	8.09	4.02	2.04	0.97
FTGTL-CCLP-07	**19.29**	**10.62**	**6.36**	**4.02**	**18.50**	**10.18**	**6.10**	**3.86**	**20.09**	**11.06**	**6.62**	**4.18**
FTGTL-CCLP-08	25.18	14.05	8.57	5.55	24.13	13.46	8.21	5.32	26.23	14.63	8.93	5.78
FTGTL-CCLP-09	**13.03**	**6.95**	**3.97**	**2.34**	**12.49**	**6.66**	**3.80**	**2.24**	**13.57**	**7.23**	**4.13**	**2.43**
FTGTL-CCLP-10	13.97	7.48	4.31	2.57	13.40	7.18	4.13	2.46	14.55	7.80	4.49	2.67
FTGTL-CCLP-11	**14.82**	**8.01**	**4.67**	**2.84**	**14.19**	**7.67**	**4.47**	**2.72**	**15.45**	**8.34**	**4.87**	**2.96**
FTGTL-CCLP-12	15.55	8.43	4.94	3.02	14.88	8.07	4.73	2.90	16.21	8.79	5.15	3.15
FTGTL-CCLP-13	**14.68**	**8.10**	**4.87**	**3.09**	**14.06**	**7.76**	**4.66**	**2.96**	**15.30**	**8.44**	**5.07**	**3.22**
FTGTL-CCLP-14	14.74	8.02	4.72	2.91	14.12	7.68	4.52	2.79	15.37	8.36	4.92	3.03
FTGTL-CCLP-15	**14.08**	**7.45**	**4.21**	**2.44**	**13.49**	**7.14**	**4.03**	**2.33**	**14.67**	**7.77**	**4.39**	**2.54**
FTGTL-CCLP-16	13.67	7.08	3.86	2.10	13.09	6.78	3.69	2.01	14.25	7.38	4.02	2.19
FTGTL-CCLP-17	**13.72**	**6.97**	**3.68**	**1.89**	**13.17**	**6.69**	**3.53**	**1.81**	**14.27**	**7.25**	**3.83**	**1.97**
FTGTL-CCLP-18	12.47	6.12	3.03	1.36	11.97	5.88	2.91	1.31	12.97	6.37	3.14	1.41

7.3 Appendix 3: NPVs Obtained from Simulations

	Option No.	NPV1 (Mean)	NPV2 (MEAN)	NPV3 (MEAN)	NPV4 (MEAN)	NPV1 (Lower Bound)	NPV2 (Lower Bound)	NPV3 (Lower Bound)	NPV4 (Lower Bound)	NPV1 (Higher Bound)	NPV2 (Higher Bound)	NPV3 (Higher Bound)	NPV4 (Higher Bound)
1	**FTGTL-CCHP-01**	**21.21**	**11.72**	**7.06**	**4.49**	**20.34**	**11.24**	**6.76**	**4.31**	**22.09**	**12.20**	**7.35**	**4.67**
2	FTGTL-CCHP-02	17.30	9.45	5.60	3.48	16.59	9.06	5.37	3.34	18.01	9.84	5.83	3.63
3	**FTGTL-CCHP-03**	**4.90**	**2.18**	**0.86**	**0.15**	**4.70**	**2.09**	**0.83**	**0.14**	**5.10**	**2.26**	**0.89**	**0.16**
4	FTGTL-CCHP-04	-10.77	-7.03	-5.14	-4.07	-11.22	-7.32	-5.36	-4.24	-10.32	-6.73	-4.93	-3.90
5	**FTGTL-CCHP-05**	**4.31**	**1.82**	**0.62**	**-0.02**	**4.13**	**1.75**	**0.60**	**-0.03**	**4.49**	**1.90**	**0.65**	**-0.01**
6	FTGTL-CCHP-06	9.73	5.02	2.72	1.47	9.31	4.80	2.60	1.40	10.14	5.23	2.83	1.53
7	**FTGTL-CCHP-07**	**23.32**	**12.97**	**7.88**	**5.02**	**22.34**	**12.43**	**7.55**	**4.87**	**24.30**	**13.52**	**8.22**	**5.30**
8	FTGTL-CCHP-08	29.32	16.48	10.16	6.68	28.12	15.81	9.75	6.41	30.51	17.16	10.58	6.95
9	**FTGTL-CCHP-09**	**15.53**	**8.43**	**4.94**	**3.03**	**14.88**	**8.07**	**4.72**	**2.90**	**16.19**	**8.78**	**5.15**	**3.15**
10	FTGTL-CCHP-10	16.61	9.05	5.34	3.30	15.91	8.67	5.11	3.16	17.31	9.43	5.56	3.44
11	**FTGTL-CCHP-11**	**17.73**	**9.72**	**5.78**	**3.62**	**16.98**	**9.31**	**5.54**	**3.47**	**18.48**	**10.13**	**6.03**	**3.77**
12	FTGTL-CCHP-12	18.82	10.34	6.18	3.89	18.02	9.90	5.92	3.73	19.62	10.78	6.44	4.05
13	**FTGTL-CCHP-13**	**18.29**	**10.20**	**6.22**	**4.02**	**17.53**	**9.77**	**5.96**	**3.86**	**19.06**	**10.62**	**6.48**	**4.19**
14	FTGTL-CCHP-14	17.84	9.83	5.90	3.73	17.10	9.43	5.65	3.58	18.58	10.24	6.14	3.89
15	**FTGTL-CCHP-15**	**16.91**	**9.12**	**5.31**	**3.22**	**16.21**	**8.75**	**5.09**	**3.08**	**17.60**	**9.50**	**5.53**	**3.35**
16	FTGTL-CCHP-16	16.71	8.87	5.03	2.93	16.03	8.51	4.82	2.81	17.38	9.22	5.23	3.05
17	**FTGTL-CCHP-17**	**15.87**	**8.30**	**4.60**	**2.58**	**15.21**	**7.95**	**4.41**	**2.47**	**16.53**	**8.64**	**4.79**	**2.69**
18	FTGTL-CCHP-18	15.73	8.02	4.26	2.21	15.09	7.69	4.08	2.12	16.37	8.34	4.43	2.30
19	**FTGTL-FCNP-01**	**18.06**	**10.14**	**6.23**	**4.08**	**17.32**	**9.72**	**5.98**	**3.91**	**18.81**	**10.56**	**6.49**	**4.25**
20	FTGTL-FCNP-02	14.52	8.08	4.90	3.15	13.94	7.75	4.70	3.02	15.14	8.41	5.10	3.28
21	**FTGTL-FCNP-03**	**2.17**	**0.81**	**0.16**	**-0.19**	**2.08**	**0.78**	**0.15**	**-0.20**	**2.26**	**0.84**	**0.17**	**-0.18**
22	FTGTL-FCNP-04	-13.12	-8.14	-5.66	-4.27	-13.68	-8.49	-5.90	-4.45	-12.56	-7.80	-5.42	-4.08
23	**FTGTL-FCNP-05**	**3.74**	**1.73**	**0.76**	**0.24**	**3.58**	**1.66**	**0.73**	**0.23**	**3.90**	**1.81**	**0.79**	**0.25**
24	FTGTL-FCNP-06	8.08	4.30	2.45	1.44	7.74	4.12	2.35	1.38	8.43	4.48	2.55	1.50
25	**FTGTL-FCNP-07**	**19.79**	**11.14**	**6.89**	**4.54**	**18.96**	**10.67**	**6.60**	**4.35**	**20.61**	**11.61**	**7.17**	**4.73**
26	FTGTL-FCNP-08	23.78	13.50	8.44	5.64	22.79	12.94	8.08	5.40	24.77	14.06	8.79	5.87
27	**FTGTL-FCNP-09**	**13.72**	**7.58**	**4.57**	**2.91**	**13.16**	**7.27**	**4.38**	**2.79**	**14.28**	**7.89**	**4.75**	**3.02**
28	FTGTL-FCNP-10	13.66	**7.57**	4.57	2.93	13.07	7.24	4.38	2.80	14.25	7.89	4.77	3.05
29	**FTGTL-FCNP-11**	**14.33**	**7.98**	**4.86**	**3.14**	**13.70**	**7.63**	**4.65**	**3.03**	**14.95**	**8.33**	**5.07**	**3.28**
30	FTGTL-FCNP-12	16.03	8.95	5.46	3.54	15.38	8.58	5.24	3.40	16.68	9.31	5.68	3.68
31	**FTGTL-FCNP-13**	**15.22**	**8.59**	**5.32**	**3.51**	**14.59**	**8.23**	**5.09**	**3.37**	**15.86**	**8.94**	**5.54**	**3.66**
32	FTGTL-FCNP-14	14.69	8.21	5.03	3.27	14.07	7.87	4.82	3.13	15.31	8.56	5.24	3.41
33	**FTGTL-FCNP-15**	**14.08**	**7.75**	**4.62**	**2.93**	**13.48**	**7.42**	**4.44**	**2.81**	**14.69**	**8.09**	**4.84**	**3.06**
34	FTGTL-FCNP-16	14.36	**7.81**	4.59	2.83	13.76	7.48	4.40	2.71	14.96	8.13	4.79	2.95
35	**FTGTL-FCNP-17**	**13.66**	**7.36**	**4.27**	**2.58**	**13.09**	**7.05**	**4.09**	**2.47**	**14.22**	**7.66**	**4.44**	**2.68**
36	FTGTL-FCNP-18	13.41	**7.10**	4.01	2.32	12.85	6.80	3.84	2.22	13.97	7.39	4.18	2.42

7.3 Appendix 3: NPVs Obtained from Simulations

	Option No.	NPV1 (Mean)	NPV2 (Mean)	NPV3 (Mean)	NPV4 (Mean)	NPV1 (Lower Bound)	NPV2 (Lower Bound)	NPV3 (Lower Bound)	NPV4 (Lower Bound)	NPV1 (Higher Bound)	NPV2 (Higher Bound)	NPV3 (Higher Bound)	NPV4 (Higher Bound)
1	**FTGTL-FCLP-01**	**18.36**	**10.32**	**6.37**	**4.19**	**17.58**	**9.89**	**6.10**	**4.01**	**19.14**	**10.76**	**6.64**	**4.36**
2	FTGTL-FCLP-02	15.62	8.71	5.31	3.44	14.97	8.34	5.09	3.29	16.28	9.08	5.53	3.58
3	**FTGTL-FCLP-03**	**3.14**	**1.38**	**0.54**	**0.08**	**3.01**	**1.33**	**0.52**	**0.08**	**3.26**	**1.44**	**0.56**	**0.09**
4	FTGTL-FCLP-04	-12.45	-7.76	-5.42	-4.11	-12.98	-8.01	-5.65	-4.28	-11.91	-7.43	-5.19	-3.93
5	**FTGTL-FCLP-05**	**4.02**	**1.91**	**0.90**	**0.34**	**3.85**	**1.84**	**0.86**	**0.33**	**4.18**	**1.99**	**0.93**	**0.36**
6	FTGTL-FCLP-06	8.97	4.81	2.77	1.66	8.59	4.61	2.66	1.59	9.35	5.02	2.89	1.73
7	**FTGTL-FCLP-07**	**20.18**	**11.39**	**7.06**	**4.67**	**19.32**	**10.91**	**6.76**	**4.48**	**21.03**	**11.89**	**7.36**	**4.87**
8	FTGTL-FCLP-08	25.67	14.60	9.15	6.13	24.59	14.00	8.76	5.88	26.75	15.22	9.53	6.39
9	**FTGTL-FCLP-09**	**14.21**	**7.88**	**4.77**	**6.06**	**13.60**	**7.54**	**4.57**	**2.93**	**14.81**	**8.22**	**4.97**	**3.19**
10	FTGTL-FCLP-10	14.60	8.12	4.94	3.18	13.99	7.78	4.73	3.05	15.21	8.46	5.14	3.31
11	**FTGTL-FCLP-11**	**16.18**	**9.04**	**5.53**	**3.60**	**15.49**	**8.66**	**5.30**	**3.44**	**16.86**	**9.42**	**5.76**	**3.75**
12	FTGTL-FCLP-12	17.12	9.59	5.88	3.83	16.42	9.19	5.63	3.67	17.83	9.98	6.12	3.99
13	**FTGTL-FCLP-13**	**16.07**	**9.08**	**5.64**	**3.74**	**15.38**	**8.69**	**5.40**	**3.58**	**16.76**	**9.47**	**5.89**	**3.91**
14	FTGTL-FCLP-14	15.73	8.82	5.42	3.55	15.08	8.46	5.20	3.40	16.38	9.18	5.64	3.69
15	**FTGTL-FCLP-15**	**14.69**	**8.12**	**4.89**	**3.12**	**14.06**	**7.77**	**4.68**	**2.98**	**15.32**	**8.47**	**5.10**	**3.25**
16	FTGTL-FCLP-16	15.00	8.20	4.87	3.04	14.36	7.85	4.66	2.91	15.65	8.56	5.08	3.16
17	**FTGTL-FCLP-17**	**14.27**	**7.73**	**4.53**	**2.77**	**13.67**	**7.41**	**4.34**	**2.65**	**14.87**	**8.06**	**4.72**	**2.88**
18	FTGTL-FCLP-18	13.63	**7.27**	4.16	2.45	13.04	6.96	3.98	2.35	14.21	7.58	4.34	2.56
19	**FTGTL-FCHP-01**	**21.53**	**12.18**	**7.58**	**5.03**	**20.62**	**11.67**	**7.26**	**4.82**	**22.44**	**12.70**	**7.90**	**5.25**
20	FTGTL-FCHP-02	18.48	10.39	6.41	4.21	17.68	9.94	6.13	4.03	19.28	10.84	6.68	4.39
21	**FTGTL-FCHP-03**	**6.24**	**3.20**	**1.71**	**0.90**	**5.98**	**3.06**	**1.64**	**0.87**	**6.50**	**3.33**	**1.78**	**0.94**
22	FTGTL-FCHP-04	-9.20	-5.84	-4.16	-3.20	-9.60	-6.10	-4.34	-3.35	-8.81	-5.60	-3.98	-3.08
23	**FTGTL-FCHP-05**	**5.56**	**2.80**	**1.46**	**0.73**	**5.34**	**2.69**	**1.40**	**0.70**	**5.79**	**2.92**	**1.52**	**0.76**
24	FTGTL-FCHP-06	11.21	6.12	3.62	2.24	10.75	5.86	3.47	2.15	11.68	6.37	3.77	2.34
25	**FTGTL-FCHP-07**	**24.26**	**13.78**	**8.61**	**5.76**	**23.24**	**13.20**	**8.25**	**5.52**	**25.28**	**14.36**	**8.97**	**6.00**
26	FTGTL-FCHP-08	30.47	17.42	10.97	7.41	29.19	16.68	10.51	7.10	31.76	18.15	11.45	7.72
27	**FTGTL-FCHP-09**	**17.47**	**9.78**	**6.00**	**3.92**	**16.76**	**9.39**	**5.76**	**3.76**	**18.17**	**10.18**	**6.24**	**4.07**
28	FTGTL-FCHP-10	18.31	10.28	6.32	4.14	17.55	9.85	6.06	3.97	19.06	10.70	6.58	4.31
29	**FTGTL-FCHP-11**	**20.10**	**11.32**	**7.00**	**4.61**	**19.26**	**10.85**	**6.71**	**4.42**	**20.94**	**11.79**	**7.29**	**4.80**
30	FTGTL-FCHP-12	20.10	11.34	7.02	4.64	19.25	10.86	6.73	4.45	20.95	11.82	7.32	4.84
31	**FTGTL-FCHP-13**	**18.56**	**10.55**	**6.61**	**4.23**	**17.77**	**10.11**	**6.33**	**4.24**	**19.34**	**11.00**	**6.89**	**4.61**
32	FTGTL-FCHP-14	18.91	10.68	6.63	4.39	18.13	10.24	6.35	4.21	19.70	11.13	6.90	4.57
33	**FTGTL-FCHP-15**	**18.48**	**10.32**	**6.30**	**4.09**	**17.70**	**9.88**	**6.04**	**3.92**	**19.25**	**10.75**	**6.57**	**4.26**
34	FTGTL-FCHP-16	17.68	9.78	5.90	3.77	16.93	9.37	5.65	3.61	18.43	10.20	6.15	3.93
35	**FTGTL-FCHP-17**	**18.17**	**9.98**	**5.96**	**3.75**	**17.43**	**9.58**	**5.72**	**3.60**	**18.91**	**10.39**	**6.20**	**3.91**
36	FTGTL-FCHP-18	16.87	9.16	5.38	3.30	16.17	8.78	5.15	3.16	17.57	9.54	5.60	3.44
37	**FTGTL-FCHP-19**	**1.79**	**0.59**	**0.01**	**-0.29**	**1.72**	**0.57**	**0.01**	**-0.30**	**1.86**	**0.61**	**0.02**	**-0.28**
38	FTGTL-FCHP-20	3.80	1.88	0.95	0.44	3.64	1.80	0.91	0.43	3.95	1.96	0.99	0.46

7.3 Appendix 3: NPVs Obtained from Simulations

	Option No.	NPV1 (Mean)	NPV2 (Mean)	NPV3 (Mean)	NPV4 (Mean)	NPV1 (Lower Bound)	NPV2 (Lower Bound)	NPV3 (Lower Bound)	NPV4 (Lower Bound)	NPV1 (Higher Bound)	NPV2 (Higher Bound)	NPV3 (Higher Bound)	NPV4 (Higher Bound)
1	**LNG-01**	**19.46**	**9.78**	**5.06**	**2.50**	**18.68**	**9.36**	**4.83**	**2.36**	**20.25**	**10.20**	**5.30**	**2.64**
2	LNG-02	15.53	7.45	3.52	1.40	14.89	7.12	3.34	1.30	16.16	7.77	3.70	1.50
3	**LNG-03**	**16.36**	**7.93**	**3.83**	**1.61**	**15.70**	**7.58**	**3.64**	**1.51**	**17.02**	**8.27**	**4.02**	**1.72**
4	LNG-04	11.72	5.22	2.07	0.39	11.23	4.97	1.95	0.33	12.21	5.46	2.20	0.45
5	**LNG-05**	**1.44**	**-0.84**	**-1.89**	**-2.42**	**1.33**	**-0.87**	**-1.92**	**-2.47**	**1.56**	**-0.82**	**-1.87**	**-2.37**
6	LNG-06	-3.06	-3.46	-3.58	-3.59	-3.11	-3.54	-3.67	-3.68	-3.00	-3.38	-3.50	-3.50
7	**LNG-07**	**8.90**	**3.56**	**0.99**	**-0.38**	**8.51**	**3.37**	**0.90**	**-0.42**	**9.30**	**3.74**	**1.07**	**-0.35**
8	LNG-08	4.25	0.85	-0.75	-1.59	4.03	0.77	-0.78	-1.61	4.47	0.94	-0.73	-1.57
9	**LNG-09**	**26.64**	**14.00**	**7.82**	**4.44**	**25.58**	**13.42**	**7.47**	**4.23**	**27.70**	**14.58**	**8.16**	**4.65**
10	LNG-10	23.06	11.86	6.40	3.42	22.14	11.37	6.11	3.25	24.00	12.35	6.68	3.60
11	**LNG-11**	**16.79**	**8.15**	**3.96**	**1.69**	**16.11**	**7.80**	**3.76**	**1.58**	**17.47**	**8.51**	**4.16**	**1.80**
12	LNG-12	12.23	5.47	2.20	0.45	11.74	5.22	2.08	0.39	12.72	5.14	2.33	0.51
13	**LNG-13**	**15.83**	**7.65**	**3.68**	**1.53**	**15.16**	**7.31**	**3.49**	**1.43**	**16.49**	**8.00**	**3.87**	**1.64**
14	LNG-14	11.87	5.29	2.11	0.40	11.38	5.05	1.99	0.35	12.35	5.53	2.23	0.46
15	**LNG-15**	**14.81**	**7.05**	**3.29**	**1.25**	**14.18**	**6.73**	**3.11**	**1.16**	**15.43**	**7.37**	**3.46**	**1.35**
16	LNG-16	12.73	5.82	2.47	0.67	12.19	5.55	2.33	0.60	13.26	6.01	2.61	0.75
17	**LNG-17**	**10.89**	**4.70**	**1.72**	**0.12**	**10.44**	**4.48**	**1.61**	**0.07**	**11.34**	**4.92**	**1.83**	**0.17**
18	**CNG-01**	**24.21**	**14.15**	**9.17**	**6.41**	**23.34**	**13.64**	**8.84**	**6.18**	**25.08**	**14.66**	**9.50**	**6.64**
19	CNG-02	12.07	7.02	4.53	3.14	11.63	6.76	4.36	3.03	12.51	7.28	4.70	3.26
20	**CNG-03**	**20.19**	**11.79**	**7.63**	**5.33**	**19.42**	**11.34**	**7.34**	**5.13**	**20.96**	**12.24**	**7.93**	**5.53**
21	CNG-04	8.52	4.94	3.17	2.19	8.20	4.75	3.05	2.10	8.84	5.12	3.29	2.27
22	**CNG-05**	**5.58**	**3.21**	**2.05**	**1.40**	**5.36**	**3.09**	**1.97**	**1.34**	**5.79**	**3.34**	**2.13**	**1.46**
23	CNG-06	-6.40	-3.82	-2.54	-1.82	-6.63	-3.95	-2.62	-1.88	-6.18	-3.68	-2.45	-1.76
24	**CNG-07**	**13.06**	**7.61**	**4.91**	**3.41**	**12.57**	**7.32**	**4.72**	**3.28**	**13.56**	**7.89**	**5.09**	**3.54**
25	CNG-08	1.05	0.55	0.31	0.18	1.00	0.53	0.30	0.17	1.10	0.58	0.33	0.13
26	**CNG-09**	**30.67**	**17.94**	**11.64**	**8.14**	**29.48**	**17.24**	**11.19**	**7.83**	**31.85**	**18.63**	**12.09**	**8.46**
27	CNG-10	19.17	11.19	7.26	5.05	18.45	10.77	6.97	4.86	19.90	11.62	7.52	5.25
28	**CNG-11**	**21.03**	**12.28**	**7.95**	**5.55**	**20.23**	**11.81**	**7.65**	**5.34**	**21.83**	**12.75**	**8.26**	**5.77**
29	CNG-12	18.55	10.83	7.00	4.89	17.85	10.42	6.74	4.70	19.26	11.24	7.28	5.08
30	**CNG-13**	**19.88**	**11.61**	**7.51**	**5.24**	**19.16**	**11.19**	**7.24**	**5.05**	**20.60**	**12.03**	**7.79**	**5.43**
31	CNG-14	-2.56	-1.56	-1.07	-0.79	-2.65	-1.62	-1.10	-0.81	-2.48	-1.51	-1.03	-0.76
32	**CNG-15**	**17.91**	**10.45**	**6.76**	**4.71**	**17.24**	**10.06**	**6.51**	**4.54**	**18.58**	**10.84**	**7.01**	**4.89**
33	CNG-16	11.35	6.60	4.25	2.95	10.93	6.35	4.09	2.84	11.78	6.85	4.41	3.06
34	**CNG-17**	**5.34**	**3.08**	**1.96**	**1.34**	**5.14**	**2.96**	**1.88**	**1.28**	**5.54**	**3.19**	**2.03**	**1.39**

7.3 Appendix 3: NPVs Obtained from Simulations

	Option No.	NPV1 (Mean)	NPV2 (Mean)	NPV3 (Mean)	NPV4 (Mean)	NPV1 (Lower Bound)	NPV2 (Lower Bound)	NPV3 (Lower Bound)	NPV4 (Lower Bound)	NPV1 (Higher Bound)	NPV2 (Higher Bound)	NPV3 (Higher Bound)	NPV4 (Higher Bound)
1	PNG-01	18.22	10.60	6.84	4.75	17.43	10.14	6.54	4.54	19.01	11.07	7.14	4.96
2	PNG-02	15.45	7.92	4.25	2.25	14.64	7.45	3.94	2.03	16.26	8.40	4.56	2.47
3	PNG-03	15.32	8.90	5.73	3.97	14.65	8.51	5.47	3.80	16.00	9.29	5.99	4.15
4	PNG-04	13.26	6.64	3.42	1.66	12.56	6.23	3.15	1.47	13.97	7.05	3.68	1.85
5	PNG-05	3.71	2.09	1.29	0.85	3.54	1.99	1.22	0.81	3.88	2.19	1.36	0.90
6	PNG-06	0.87	-0.63	-1.32	-1.67	0.70	-0.73	-1.39	-1.71	1.04	-0.53	-1.26	-1.62
7	PNG-07	10.00	5.78	3.70	2.54	9.58	5.53	3.53	2.43	10.43	6.03	3.86	2.66
8	PNG-08	6.52	2.69	0.84	-0.15	6.10	2.44	0.68	-0.26	6.95	2.93	1.00	-0.34
9	PNG-09	25.91	15.12	9.78	6.82	24.85	14.49	9.37	6.53	2.70	15.74	10.19	7.10
10	PNG-10	21.77	11.63	6.67	3.95	20.70	11.00	6.26	3.66	22.84	12.26	7.08	4.24
11	PNG-11	15.64	9.14	5.93	4.14	14.96	8.74	5.67	3.96	16.31	9.54	6.19	4.33
12	PNG-12	14.75	8.20	4.98	3.20	14.07	7.80	4.72	3.02	15.43	8.60	5.24	3.39
13	PNG-13	15.66	9.01	5.73	3.91	14.96	8.60	5.47	3.73	16.35	9.42	6.00	4.10
14	PNG-14	9.91	3.53	0.48	-1.14	9.24	3.14	0.22	-1.32	1.58	3.92	0.73	-0.96
15	PNG-15	14.52	8.17	5.04	3.32	13.84	7.77	4.78	3.13	15.20	8.57	5.30	3.50
16	PNG-16	13.49	7.03	3.88	2.16	12.80	6.63	3.62	1.97	14.17	7.44	4.14	2.34
17	PNG-17	11.94	5.59	2.52	0.86	11.25	5.19	2.26	0.68	12.62	6.00	2.78	1.05

	Option No	NPV1 (Mean)	NPV2 (Mean)	NPV3 (Mean)	NPV4 (Mean)	NPV1 (Lower Bound)	NPV2 (Lower Bound)	NPV3 (Lower Bound)	NPV4 (Lower Bound)	NPV1 (Higher Bound)	NPV2 (Higher Bound)	NPV3 (Higher Bound)	NPV4 (Higher Bound)
1	GTW-01	25.19	6.15	-2.88	-7.60	24.24	5.91	-3.00	-7.88	26.15	6.38	-2.77	-7.31
2	GTW-02	21.62	4.30	-4.27	-8.58	20.80	3.88	-4.43	-8.91	22.43	4.19	-4.11	-8.26
3	GTW-03	7.32	-4.58	-10.06	-12.80	7.05	-4.75	-10.43	-13.27	7.59	-4.41	-9.69	-12.33
4	GTW-04	37.82	17.80	8.09	2.86	36.43	17.14	7.80	2.75	39.21	18.45	8.39	2.96
5	GTW-05	4.93	-1.69	-4.75	-6.30	4.75	-1.75	-4.92	-6.52	5.11	-1.63	-4.58	-6.07
6	GTW-06	-9.61	-22.93	-28.72	-31.34	-9.97	-23.78	-29.79	-32.50	-9.25	-22.07	-27.65	-30.17
7	GTW-07	-0.98	-9.33	-13.06	-14.83	-1.02	-9.68	-1.36	-15.38	-0.95	-8.98	-1.26	-14.27
8	GTW-08	56.50	24.16	8.77	0.53	53.92	23.24	8.44	0.51	59.19	25.07	9.10	0.55
9	GTW-09	25.12	-3.17	-16.35	-23.05	24.20	-3.29	-16.95	-23.89	26.04	-3.06	-15.75	-22.21
10	GTW-10	150.22	79.24	44.53	25.55	144.74	76.35	42.90	24.62	155.70	82.13	46.15	26.48
11	GTW-11	118.36	51.59	19.36	2.09	114.13	49.75	18.67	2.01	122.59	54.43	20.06	2.16
12	GTW-12	86.09	32.36	6.61	-7.07	82.92	31.17	6.36	-7.33	89.27	33.56	6.85	-6.81
13	GTW-13	21.90	-32.45	-57.27	-69.47	21.10	-33.65	-59.38	-72.04	22.71	-31.25	-55.14	-66.91

7.3 Appendix 3: NPVs Obtained from Simulations

	Option No.	NPV1 (Mean)	NPV2 (Mean)	NPV3 (Mean)	NPV4 (Mean)	NPV1 (Lower Bound)	NPV2 (Lower Bound)	NPV3 (Lower Bound)	NPV4 (Lower Bound)	NPV1 (Higher Bound)	NPV2 (Higher Bound)	NPV3 (Higher Bound)	NPV4 (Higher Bound)
1	**DME-01**	**16.43**	**9.11**	**5.51**	**3.53**	**16.30**	**9.02**	**5.48**	**3.51**	**16.57**	**9.20**	**5.54**	**3.54**
2	DME-02	12.32	6.71	3.95	2.44	12.18	6.62	3.92	2.43	12.46	6.80	3.99	2.46
3	**DME-03**	**-1.96**	**-1.68**	**-1.52**	**-1.41**	**-2.10**	**-1.77**	**-1.55**	**-1.43**	**-1.81**	**-1.59**	**-1.49**	**-1.40**
4	DME-04	9.26	4.89	2.76	1.59	9.12	4.80	2.72	1.57	9.41	4.99	2.79	1.60
5	**DME-05**	**0.22**	**-0.40**	**-0.68**	**-0.81**	**0.08**	**-0.49**	**-0.71**	**-0.83**	**0.36**	**-0.30**	**-0.64**	**-0.80**
6	DME-06	5.44	2.66	1.30	0.57	5.31	2.57	1.27	0.56	5.58	2.75	1.34	0.58
7	**DME-07**	**24.34**	**13.74**	**8.52**	**5.64**	**24.20**	**13.65**	**8.49**	**5.63**	**24.48**	**13.83**	**8.55**	**5.65**
1	**Methanol-01**	**12.45**	**6.22**	**3.18**	**1.53**	**12.31**	**6.13**	**3.15**	**1.52**	**12.59**	**6.31**	**3.22**	**1.55**
2	Methanol-02	8.95	4.15	1.83	0.58	8.80	4.06	1.80	0.57	9.09	4.24	1.86	0.59
3	**Methanol-03**	**-5.89**	**-4.56**	**-3.85**	**-3.42**	**-6.04**	**-4.65**	**-3.89**	**-3.44**	**-5.75**	**-4.47**	**-3.82**	**-3.41**
4	Methanol-04	0.60	-0.72	-1.33	-1.63	0.46	-0.81	-1.36	-1.64	0.74	-0.63	-1.29	-1.61
5	**Methanol-05**	**20.90**	**11.13**	**6.35**	**3.73**	**20.76**	**11.04**	**6.32**	**3.72**	**21.04**	**11.22**	**6.38**	**3.74**
6	Methanol-06	35.60	19.82	12.05	7.78	35.46	19.72	12.02	7.77	35.74	19.91	12.09	7.80
1	MTO-01	24.70	13.63	8.20	5.21	24.56	13.54	8.16	5.20	24.84	13.73	8.23	5.22
2	**MTO-02**	**21.70**	**11.86**	**7.03**	**4.37**	**21.56**	**11.77**	**6.99**	**4.36**	**21.85**	**11.95**	**7.06**	**4.39**
3	MTO-03	6.53	2.96	1.24	0.31	6.39	2.87	1.20	0.29	6.67	3.05	1.27	0.32
4	MTO-04	7.07	3.29	1.46	0.48	6.93	3.20	1.43	0.46	7.20	3.38	1.49	0.49
5	MTO-05	14.20	7.47	4.17	2.38	14.07	7.38	4.14	2.36	14.34	7.56	4.21	2.39
6	MTO-06	28.03	15.59	9.47	6.10	27.89	15.50	9.44	6.09	28.18	15.67	9.50	6.11

7.3 Appendix 3: NPVs Obtained from Simulations

	Option No.	NPV1 (Mean)	NPV2 (Mean)	NPV3 (Mean)	NPV4 (Mean)	NPV1 (Lower Bound)	NPV2 (Lower Bound)	NPV3 (Lower Bound)	NPV4 (Lower Bound)	NPV1 (Higher Bound)	NPV2 (Higher Bound)	NPV3 (Higher Bound)	NPV4 (Higher Bound)
1	GTS-01	20.45	11.83	7.57	5.21	19.71	11.40	7.29	5.02	21.19	12.26	7.84	5.40
2	GTS-02	19.55	11.31	7.23	4.98	18.80	10.87	6.95	4.78	20.31	11.75	7.52	5.17
3	GTS-03	15.75	9.07	5.78	3.95	15.14	8.72	5.56	3.80	16.35	9.40	6.00	4.11
4	GTS-04	16.28	9.38	5.98	4.09	15.67	9.03	5.75	3.94	16.89	9.73	6.20	4.24
5	GTS-05	1.33	0.61	0.26	0.08	1.27	0.58	0.25	0.07	1.39	0.64	0.28	0.08
6	GTS-06	1.31	0.60	0.26	0.07	1.25	0.57	0.24	0.06	1.37	0.63	0.27	0.08
7	GTS-07	8.78	4.98	3.11	2.08	8.44	4.79	2.99	2.00	9.12	5.18	3.23	2.16
8	GTS-08	8.91	5.06	3.16	2.11	8.57	4.86	3.03	2.03	9.25	5.25	3.28	2.19
9	GTS-09	27.01	15.68	10.08	6.98	25.99	15.09	9.70	6.70	28.02	16.27	10.46	7.24
10	GTS-10	27.39	15.90	10.22	7.08	26.36	15.30	9.84	6.81	28.41	16.50	10.61	7.35
11	GTS-11	15.50	8.84	5.55	3.73	14.90	8.49	5.33	3.58	16.10	9.18	5.77	3.88
12	GTS-12	16.01	9.13	5.73	3.86	15.41	8.78	5.52	3.72	16.60	9.47	5.95	4.01
13	GTS-13	14.97	8.42	5.20	3.42	14.39	8.10	5.00	3.28	15.54	8.75	5.41	3.56
14	GTS-14	15.01	8.84	5.46	3.60	15.10	8.50	5.25	3.46	16.30	9.18	5.68	3.75
15	GTS-15	16.43	9.47	6.03	4.13	15.81	9.11	5.80	3.97	17.05	9.83	6.62	4.29
16	GTS-16	16.11	9.28	5.91	4.05	15.51	8.94	5.69	3.89	16.71	9.63	6.14	4.20
17	GTS-17	16.21	9.34	5.95	4.07	15.60	8.99	5.73	3.92	16.82	9.70	6.18	4.23

	Option No	NPV1 (Mean)	NPV2 (Mean)	NPV3 (Mean)	NPV4 (Mean)	NPV1 (Lower Bound)	NPV2 (Lower Bound)	NPV3 (Lower Bound)	NPV4 (Lower Bound)	NPV1 (Higher Bound)	NPV2 (Higher Bound)	NPV3 (Higher Bound)	NPV4 (Higher Bound)
1	Ref-C-01	3.45	2.19	0.49	-0.02	3.31	2.10	0.46	-0.03	3.59	2.28	0.53	-0.01
2	Ref-C-02	3.22	2.05	0.44	-0.04	3.08	1.96	0.41	-0.06	3.36	2.14	0.47	-0.003
3	Ref-C-03	3.33	2.11	0.47	-0.03	3.18	2.02	0.44	-0.04	3.47	2.21	0.50	-0.01
4	Ref-C-04	3.40	2.16	0.48	-0.02	3.25	2.07	0.45	-0.04	3.54	2.25	0.52	-0.01
5	Ref-C-05	3.25	2.07	0.45	-0.04	3.11	2.00	0.42	-0.05	3.40	2.16	0.48	-0.02
6	Ref-C-06	1.78	1.12	-0.11	-0.43	1.69	1.06	-0.12	-0.43	1.87	1.17	-0.96	-0.42
7	Ref-C-07	2.57	1.62	0.18	-0.23	2.45	1.55	0.16	-0.24	2.68	1.70	0.20	-0.22
8	Ref-C-08	4.11	2.62	0.76	0.18	3.94	2.51	0.72	0.16	4.29	2.73	0.81	0.20
9	Ref-C-09	4.63	2.96	0.98	0.34	4.44	2.83	0.93	0.31	4.82	3.08	0.10	0.37

1	Ref-F-01	-1.83	-2.50	-2.77	-2.87	-1.97	-2.59	-2.80	-2.88	-1.69	-2.41	-2.74	-2.85
2	Ref-F-02	-0.32	-1.63	-2.22	-2.50	-0.46	-1.73	-2.25	-2.51	-0.17	-1.54	-2.19	-2.48

7.4 Appendix 4: Scenarios Simulated for and Their Parameters

	Option Number	NG Cost ($/MMBTU)	Product Value ($/barrel)	Crude oil price($/barrel)	Refinery Profit Margin ($/barrel)	Base capacity (bpd)
1	**FTGTL-CCNP-01**	**0**	**64**	**50**	**14**	**34,000**
2	FTGTL-CCNP-02	1	64	50	14	34,000
3	**FTGTL-CCNP-03**	**5**	**64**	**50**	**14**	**34,000**
4	FTGTL-CCNP-04	10	64	50	14	34,000
5	**FTGTL-CCNP-05**	**1**	**29**	**15**	**14**	**34,000**
6	FTGTL-CCNP-06	1	44	30	14	34,000
7	**FTGTL-CCNP-07**	**1**	**79**	**65**	**14**	**34,000**
8	FTGTL-CCNP-08	1	94	80	14	34,000
9	**FTGTL-CCNP-09**	**1**	**60**	**50**	**10**	**34,000**
10	FTGTL-CCNP-10	1	62	50	12	34,000
11	**FTGTL-CCNP-11**	**1**	**66**	**50**	**16**	**34,000**
12	FTGTL-CCNP-12	1	68	50	18	34,000
13	**FTGTL-CCNP-13**	**1**	**64**	**50**	**14**	**15000**
14	FTGTL-CCNP-14	1	64	50	14	25000
15	**FTGTL-CCNP-15**	**1**	**64**	**50**	**14**	**50000**
16	FTGTL-CCNP-16	1	64	50	14	75000
17	**FTGTL-CCNP-17**	**1**	**64**	**50**	**14**	**100000**
18	FTGTL-CCNP-18	1	64	50	14	150000

19	**FTGTL-CCLP-01**	**0**	**67.2**	**50**	**14**	**34,000**
20	FTGTL-CCLP-02	1	67.2	50	14	34,000
21	**FTGTL-CCLP-03**	**5**	**67.2**	**50**	**14**	**34,000**
22	FTGTL-CCLP-04	10	67.2	50	14	34,000
23	**FTGTL-CCLP-05**	**1**	**30.5**	**15**	**14**	**34,000**
24	FTGTL-CCLP-06	1	46.2	30	14	34,000
25	**FTGTL-CCLP-07**	**1**	**83**	**65**	**14**	**34,000**
26	FTGTL-CCLP-08	1	98.7	80	14	34,000
27	**FTGTL-CCLP-09**	**1**	**63**	**50**	**10**	**34,000**
28	FTGTL-CCLP-10	1	65.1	50	12	34,000
29	**FTGTL-CCLP-11**	**1**	**69.3**	**50**	**16**	**34,000**
30	FTGTL-CCLP-12	1	71.4	50	18	34,000
31	**FTGTL-CCLP-13**	**1**	**67.2**	**50**	**14**	**15000**
32	FTGTL-CCLP-14	1	67.2	50	14	25000
33	**FTGTL-CCLP-15**	**1**	**67.2**	**50**	**14**	**50000**
34	FTGTL-CCLP-16	1	67.2	50	14	75000
35	**FTGTL-CCLP-17**	**1**	**67.2**	**50**	**14**	**100000**
36	FTGTL-CCLP-18	1	67.2	50	14	150000

7.4 Appendix 4: Scenarios Simulated for and Their Parameters

	Option Number	NG Cost ($/MMBTU)	Product Value ($/barrel)	Crude oil price ($/barrel)	Refinery Profit Margin ($/barrel)	Base capacity (bpd)
1	**FTGTL-CCHP-01**	**0**	**76.8**	**50**	**14**	**34,000**
2	FTGTL-CCHP-02	1	**76.8**	50	14	34,000
3	**FTGTL-CCHP-03**	**5**	**76.8**	**50**	**14**	**34,000**
4	FTGTL-CCHP-04	10	**76.8**	50	14	34,000
5	**FTGTL-CCHP-05**	**1**	**34.8**	**15**	**14**	**34,000**
6	FTGTL-CCHP-06	1	**52.8**	30	14	34,000
7	**FTGTL-CCHP-07**	**1**	**94.8**	**65**	**14**	**34,000**
8	FTGTL-CCHP-08	1	**112.8**	80	14	34,000
9	**FTGTL-CCHP-09**	**1**	**72**	**50**	**10**	**34,000**
10	FTGTL-CCHP-10	1	**74.4**	50	12	34,000
11	**FTGTL-CCHP-11**	**1**	**79.2**	**50**	**16**	**34,000**
12	FTGTL-CCHP-12	1	**81.6**	50	18	34,000
13	**FTGTL-CCHP-13**	**1**	**76.8**	**50**	**14**	**15000**
14	FTGTL-CCHP-14	1	**76.8**	50	14	25000
15	**FTGTL-CCHP-15**	**1**	**76.8**	**50**	**14**	**50000**
16	FTGTL-CCHP-16	1	**76.8**	50	14	75000
17	**FTGTL-CCHP-17**	**1**	**76.8**	**50**	**14**	**100000**
18	FTGTL-CCHP-18	1	**76.8**	50	14	150000

19	**FTGTL-FCNP-01**	**0**	**64**	**50**	**14**	**34,000**
20	FTGTL-FCNP-02	1	**64**	50	14	34,000
21	**FTGTL-FCNP-03**	**5**	**64**	**50**	**14**	**34,000**
22	FTGTL-FCNP-04	10	**64**	50	14	34,000
23	**FTGTL-FCNP-05**	**1**	**29**	**15**	**14**	**34,000**
24	FTGTL-FCNP-06	1	**44**	30	14	34,000
25	**FTGTL-FCNP-07**	**1**	**79**	**65**	**14**	**34,000**
26	FTGTL-FCNP-08	1	**94**	80	14	34,000
27	**FTGTL-FCNP-09**	**1**	**60**	**50**	**10**	**34,000**
28	FTGTL-FCNP-10	1	**62**	50	12	34,000
29	**FTGTL-FCNP-11**	**1**	**66**	**50**	**16**	**34,000**
30	FTGTL-FCNP-12	1	**68**	50	18	34,000
31	**FTGTL-FCNP-13**	**1**	**64**	**50**	**14**	**15000**
32	FTGTL-FCNP-14	1	**64**	50	14	25000
33	**FTGTL-FCNP-15**	**1**	**64**	**50**	**14**	**50000**
34	FTGTL-FCNP-16	1	**64**	50	14	75000
35	**FTGTL-FCNP-17**	**1**	**64**	**50**	**14**	**100000**
36	FTGTL-FCNP-18	1	**64**	50	14	150000

7.4 Appendix 4: Scenarios Simulated for and Their Parameters

	Option Number	NG Cost ($/MMBTU)	Product Value ($/barrel)	Crude oil price($/barrel)	Refinery Profit Margin ($/barrel)	Base capacity (bpd)
1	**FTGTL-FCLP-01**	**0**	**67.2**	**50**	**14**	**34,000**
2	FTGTL-FCLP-02	1	**67.2**	50	14	34,000
3	**FTGTL-FCLP-03**	**5**	**67.2**	**50**	**14**	**34,000**
4	FTGTL-FCLP-04	10	**67.2**	50	14	34,000
5	**FTGTL-FCLP-05**	**1**	**30.45**	**15**	**14**	**34,000**
6	FTGTL-FCLP-06	1	**46.2**	30	14	34,000
7	**FTGTL-FCLP-07**	**1**	**82.95**	**65**	**14**	**34,000**
8	FTGTL-FCLP-08	1	**98.7**	80	14	34,000
9	**FTGTL-FCLP-09**	**1**	**63**	**50**	**10**	**34,000**
10	FTGTL-FCLP-10	1	**65.1**	50	12	34,000
11	**FTGTL-FCLP-11**	**1**	**69.3**	**50**	**16**	**34,000**
12	FTGTL-FCLP-12	1	**71.4**	50	18	34,000
13	**FTGTL-FCLP-13**	**1**	**67.2**	**50**	**14**	**15000**
14	FTGTL-FCLP-14	1	**67.2**	50	14	25000
15	**FTGTL-FCLP-15**	**1**	**67.2**	**50**	**14**	**50000**
16	FTGTL-FCLP-16	1	**67.2**	50	14	75000
17	**FTGTL-FCLP-17**	**1**	**67.2**	**50**	**14**	**100000**
18	FTGTL-FCLP-18	1	**67.2**	50	14	150000
19	**FTGTL-FCHP-01**	**0**	**76.8**	**50**	**14**	**34,000**
20	FTGTL-FCHP-02	1	**76.8**	50	14	34,000
21	**FTGTL-FCHP-03**	**5**	**76.8**	**50**	**14**	**34,000**
22	FTGTL-FCHP-04	10	**76.8**	50	14	34,000
23	**FTGTL-FCHP-05**	**1**	**34.8**	**15**	**14**	**34,000**
24	FTGTL-FCHP-06	1	**52.8**	30	14	34,000
25	**FTGTL-FCHP-07**	**1**	**94.8**	**65**	**14**	**34,000**
26	FTGTL-FCHP-08	1	**112.8**	80	14	34,000
27	**FTGTL-FCHP-09**	**1**	**72**	**50**	**10**	**34,000**
28	FTGTL-FCHP-10	1	**74.4**	50	12	34,000
29	**FTGTL-FCHP-11**	**1**	**79.2**	**50**	**16**	**34,000**
30	FTGTL-FCHP-12	1	**81.6**	50	18	34,000
31	**FTGTL-FCHP-13**	**1**	**76.8**	**50**	**14**	**15000**
32	FTGTL-FCHP-14	1	**76.8**	50	14	25000
33	**FTGTL-FCHP-15**	**1**	**76.8**	**50**	**14**	**50000**
34	FTGTL-FCHP-16	1	**76.8**	50	14	75000
35	**FTGTL-FCHP-17**	**1**	**76.8**	**50**	**14**	**100000**
36	FTGTL-FCHP-18	1	**76.8**	50	14	150000
37	**FTGTL-FCHP-19**	**10**	**112.8**	**80**	**14**	**34,000**
38	FTGTL-FCHP-20	10	38.4	18	14	15,000

7.4 Appendix 4: Scenarios Simulated for and Their Parameters

	Option No	NG Cost ($/MMBTU)	Product Value ($/MMBTU)	Shipping Distance (Km)	Shipping Cost($/MMBTU/1000Km)
1	LNG-01	0	7	500	0.2
2	LNG-02	0	7	6482	0.2
3	LNG-03	1	7	500	0.2
4	LNG-04	1	7	6482	0.2
5	LNG-05	5	7	500	0.2
6	LNG-06	5	7	6482	0.2
7	LNG-07	1	5	500	0.2
8	LNG-08	1	5	6482	0.2
9	LNG-09	1	10	500	0.2
10	LNG-10	1	10	6482	0.2
11	LNG-11	1	7	500	0.1
12	LNG-12	1	7	6482	0.1
13	LNG-13	1	7	500	1
14	LNG-14	1	7	6482	1
15	LNG-15	1	7	2000	0.2
16	LNG-16	1	7	5000	0.2
17	LNG-17	1	7	8000	0.2
18	CNG-01	0	7	500	0.54
19	CNG-02	0	7	6482	0.54
20	CNG-03	1	7	500	0.54
21	CNG-04	1	7	6482	0.54
22	CNG-05	5	7	500	0.54
23	CNG-06	5	7	6482	0.54
24	CNG-07	1	5	500	0.54
25	CNG-08	1	5	6482	0.54
26	CNG-09	1	10	500	0.54
27	CNG-10	1	10	6482	0.54
28	CNG-11	1	7	500	0.1
29	CNG-12	1	7	6482	0.1
30	CNG-13	1	7	500	1
31	CNG-14	1	7	6482	1
32	CNG-15	1	7	2000	0.54
33	CNG-16	1	7	5000	0.54
34	CNG-17	1	7	8000	0.54

7.4 Appendix 4: Scenarios Simulated for and Their Parameters

	Option No.	NG Cost ($/MMBTU)	Product Value ($/MMBTU)	Piping Distance (Km)	Piping Cost($/Km)
1	PNG-01	0	7	500	500000
2	PNG-02	0	7	6482	500000
3	PNG-03	1	7	500	500000
4	PNG-04	1	7	6482	500000
5	PNG-05	5	7	500	500000
6	PNG-06	5	7	6482	500000
7	PNG-07	1	5	500	500000
8	PNG-08	1	5	6482	500000
9	PNG-09	1	10	500	500000
10	PNG-10	1	10	6482	500000
11	PNG-11	1	7	500	200000
12	PNG-12	1	7	6482	200000
13	PNG-13	1	7	500	1000000
14	PNG-14	1	7	6482	1000000
15	PNG-15	1	7	2000	500000
16	PNG-16	1	7	5000	500000
17	PNG-17	1	7	8000	500000

	Option No.	Crude oil price($/barrel)	Product Value ($/barrel)	Refinery Profit Margin ($/barrel)
1	Ref-C-01	50	64	14
2	Ref-C-02	15	29	14
3	Ref-C-03	30	44	14
4	Ref-C-04	65	79	14
5	Ref-C-05	80	94	14
6	Ref-C-06	50	60	10
7	Ref-C-07	50	62	12
8	Ref-C-08	50	66	16
9	Ref-C-09	50	68	18
1	Ref-F-01	50	64	14
2	Ref-F-02	50	68	18

7.4 Appendix 4: Scenarios Simulated for and Their Parameters

	Option No.	NG Cost ($/MMBTU)	Product Value ($/MMBTU)	Shipping Distance (Km)	Shipping Cost($/MMBTU)	Base CAPEX ($/MMBTU)
1	GTS-01	0	7	500	1.32	3.2
2	GTS-02	0	7	6482	1.32	3.2
3	GTS-03	1	7	500	1.32	3.2
4	GTS-04	1	7	6482	1.32	3.2
5	GTS-05	5	7	500	1.32	3.2
6	GTS-06	5	7	6482	1.32	3.2
7	GTS-07	1	5	500	1.32	3.2
8	GTS-08	1	5	6482	1.32	3.2
9	GTS-09	1	10	500	1.32	3.2
10	GTS-10	1	10	6482	1.32	3.2
11	GTS-11	1	7	500	1.32	5
12	GTS-12	1	7	6482	1.32	5
13	GTS-13	1	7	500	1.32	7
14	GTS-14	1	7	6482	1.32	7
15	GTS-15	1	7	2000	1.32	3.2
16	GTS-16	1	7	5000	1.32	3.2
17	GTS-17	1	7	8000	1.32	3.2

	Option No.	NG Cost ($/MMBTU)	Price of power ($/MW)	CAPEX($/W)
1	GTW-01	0	50	1
2	GTW-02	1	50	1
3	GTW-03	5	50	1
4	GTW-04	1	50	0.5
5	GTW-05	10	50	0.5
6	GTW-06	1	50	2
7	GTW-07	1	30	1
8	GTW-08	1	80	1
9	GTW-09	1	80	2
10	GTW-10	1	160	1
11	GTW-11	1	160	2
12	GTW-12	10	160	2
13	GTW-13	1	160	5

7.4 Appendix 4: Scenarios Simulated for and Their Parameters

	Option No.	NG Cost ($/MMBTU)	Product Value ($/ton)
1	DME-01	0	250
2	DME-02	1	250
3	DME-03	5	250
4	DME-04	5	400
5	DME-05	1	80
6	DME-06	1	150
7	DME-07	1	400

1	Methanol-01	0	150
2	Methanol-02	1	150
3	Methanol-03	5	150
4	Methanol-04	1	75
5	Methanol-05	1	250
6	Methanol-06	1	400

1	MTO-01	0	800
2	MTO-02	1	800
3	MTO-03	5	800
4	MTO-04	1	400
5	MTO-05	1	600
6	MTO-06	1	1000