Economic Viability of a Floating Gas-to-Liquids (GTL) Plant

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Dissertation submitted in partial fulfilment of the requirements for the degree *Master of Engineering* at the Potchefstrom Campus of the North-West University

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May 2007

EXECUTIVE SUMMARY

Today, a large proportion of the world's plenteous *offshore natural gas resource* are stranded, flared or re-injected due to constraints pertaining to its utilisation. The major constraint in the utilisation of this resource is linked to its properties, which makes it difficult to transport or store.

Although the resource presents an excellent opportunity for the Gas-to-Liquid (GTL) technology (*process for converting natural gas into high energy liquid fuels with qualities that surpass the most stringent current and future clean-fuel requirements*), the further processing of this resource is still impeded by high cost of transportation.

However, it is believed that the emerging Floating GTL concept could offer superb opportunities to bring such offshore stranded natural gas reserves to markets by converting the gas into high quality liquid fuels, at the production sites, before it is transported using conventional oil tankers or vessels. But the question is: *can this venture be profitable or economically viable?*

In response, an Economic Model (the EV Model) to review the economic viability of the Floating GTL option was developed. Analyses on technical and economical aspects of the floating GTL application offshore are presented with case studies on Syntroleum's and Statoil's floating GTL designs.

Profitability analyses were conducted using the EV model to evaluate economic parameters such as Net Present Value (NPV), Internal Rate of Return (IRR), Discounted PayBack Period (DPBP), Profitability Index (PI), Break-Even Analysis (BEA) and Scale Economies for some assumed case

scenarios involving both designs. In addition, sensitivity analyses were also carried out to find the most sensitive parameters which affect the viability of the floating GTL option.

The economic analyses revealed that, a modest feedstock cost (~0 - $3/MSCF), high crude oil price (that stays above $30 per barrel) and reduction trend in capital expenditure (for stand alone Floating GTL plant) up to $20,000/BPD or lower in the next few years, will open windows for the floating GTL concept.

Finally, the energy policy needed to achieve the capitalisation of the plenteous offshore stranded gas resource via floating GTL is also discussed.

Keywords: *stranded gas, Gas- to-Liquids (GTL), floating GTL, Internal Rate of Return, Net Present Value, Profitability Index, Discounted PayBack time, Break-Even Analysis and Scale Economies.*

ACKNOWLEDGEMENT

All the Glory is to God Almighty for giving me the ability to carry on through till the end with this research work. I got my inspiration from His Living Word that says 'I can do all things through Christ that strengthens me'.

The moral support I received from my wife, Oyepeju cannot be estimated. Even at my very low moments she kept on encouraging and challenging me. I'm indeed very grateful to God for making her an important part of my life. I love you dear! My daughter Nichelle is not left out as she gave her support in her own little way, by mumbling soothing words that God alone understands. I love you my darling daughter.

Professor Piet Stoker's contribution to this work cannot be over-emphasized. He was more than just a Project Supervisor; he definitely affected me positively in countless ways. My encounter with him in my life time is one I will always be grateful to God Almighty for. His immense contributions made this work to come out the way it did today. Thank you so much sir!

Mr. Adolf Wolmarans, my Plant Manager at Sasol Infragas, Industry Supervisor and Mentor also contributed so much to see that this work is a success. He invested so much time and his expertise in the field of Management and Process Engineering to see that I complete this work successfully.

I'll also like to acknowledge Dr. Iraj Isaac Rahmim, the CEO of E-Meta Venture Inc, USA, who acted as my virtual Industry Supervisor and Mentor. He found time out of his very busy schedule to see that he got answers to my

never ending questions, by maintaining constant communication with me via e-mail and observing the progress of my work. He did all these despite the fact that we have never met.

Professor Harry Witchers of the CRCED also contributed to the successful completion of this work. He was there at the very beginning, taking me through the foundation of Research Methodology. Mrs Sandra Stoker, Secretary at CRCED and wife our very own Professor Stoker was also there every inch of the way; making sure that there is no break in transmission and ensuring delivery on schedule.

My very good friends, Chioma Aso-Goggins, an Electrical Engineer at Jabil Circuit Inc – USA, Pakama Gcabo a Process Engineer at SASTECH R&D and my colleague Tunji Adekoya were with me all the way, editing and making suggestions where and when necessary.

All this would have been almost impossible without the help of the Sasol Infonet crew, especially, Joyce Gazi and Kate Smuts. They were really of great assistance with research study texts, journals, e-books and other study materials I used for my entire M. Eng Development and Management program at the North West University (NWU).

Jacobus Kaiser and Carel Watkins of Sasol ATR were also helpful. Sanneline Westhuisen a PHD student in my research class (NWU) made so much contribution to this work. I'm sure she doesn't even know how much she contributed to my work! Her wealth of experience in research is something I had to tap from.

Mathias Akhideno of Shell, Holland, Netherlands; Mrs Ogunrombi a PHD student at the NWU Potchefstrom campus; and, Femi Akindoju and Kunle Amusan of Chevron Nigeria also made contributions in their own very special way. My colleagues with the EGTL project team especially, Kelvin, Wallace, Inyang, Victor, Lucky, Hamed, Uzo, Saheed and Abraham; and the Sasol ATR Shift II production team also contributed in one way or the other to the successful completion of this work. I'll also like to specially thank all the M.Eng Development and Management NWU students (2005 and 2006 session) for being very supportive.

To every member of my family, I'll like to say thank you, especially my Mother, Mrs Margaret Bassey; my Sisters, Mabel, Helen and Becky; My brothers, Edwin, Richie, Daniel and Emmanuel; My cousin Maurice Ekong; my mother inlaw, Mrs Eunice Jegede; My brother-in-law, Oyeleke and finally, My Sisters-in-law, Oyebisi, Oyebola and Oyelayo Jegede. Thank you all for being undoubtedly supportive. God bless you all.

Special thanks to Chevron Nigeria Limited for making it possible for me to have this experience of studying in South Africa. Also special thanks to Mr. Tunde Oyadiran, the EGTL mentor and Chris Peens the EGTL Production Manager for approving my move to study in South Africa.

DEDICATION

This research work is dedicated to the memories of my late father Mr. Ephraim Attah Bassey and my late Uncle Mr. Nyong Okon-Ekong.

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CAPEX:	Capital Expenditure
OPEX	Operating Expenditure
CF	Cash Flow
CO	Initial Cash Outflow
DCF	Discounted Cash Flow
ADR	Annual Depreciation Rate
DR	Discount Rate
DF	Discount Factor
$	US Dollar
$/BPD	US Dollars per Barrel Per Day
EBIT	Earnings Before Interest or Tax
NWC	Net Working Capital
GI	Gross Income
D	Depreciation
TR	Tax Rate
T	Tax
PP	Product Price
MC	Maintenance Cost
OC	Operating 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
PI	Profitability Index
DPBP	Discounted Payback Period
E of S	Economy of Scale
BTU	British Thermal Units
Bbl	Barrel
SCF	Standard Cubic Feet

BTU/SCF	British Thermal Units/Standard Cubic Feet
MM	Million
M	Thousand
MMSCF	Million Standard cubic feet
MSCF	Thousand Standard cubic feet
MMSCF/D	Million Standard cubic feet per day
MMBTU	Million British Thermal Units
BCF	Billion cubic feet
TCF	Trillion cubic feet
BCF	Billions cubic feet
BPD	Barrels Per Day
GJ	Giga Joules
PC	Plant Capacity
BC	Base Case
BC1	Base Case Scenario 1
BC2	Base Case Scenario 2

CHAPTER ONE

INTRODUCTION

1.1 INTRODUCTION

The offshore industry, for the most part, is geared towards the production of crude oil, which, being liquid, can be easily transported by tanker to virtually any market in the world. The natural gas produced in association with the crude oil, however, presents a problem because gas cannot be easily stored and transported.

Millions of years ago, the remains of plants and animals decayed and built up in thick layers. This decayed matter from plants and animals (called organic material) over time was trapped beneath the rock formed from mud and soil. Pressure and heat changed some of this organic material into coal, some into oil (crude oil/petroleum), and some into natural gas (tiny bubbles of odourless gas) (Microsoft Encarta Reference Library, 2005).

Natural gas is a gaseous fossil fuel consisting primarily of methane. It is found in oil and gas fields, and in coal beds. It is commercially produced from oil and natural gas fields. Gas produced from oil wells is called casing head gas or associated gas (also known as natural gas). Natural gas is an abundant resource that sits virtually untapped.

Agee (2005) stated that there is an estimated 3,000 trillion cubic feet (cf) of stranded natural gas (these are reserves that cannot be easily reached by conventional exploration due to economic reasons) around the world with the potential of creating several hundred billion barrels of oil equivalent,

comparable to the oil reserves of Saudi Arabia and representing billions of dollars in un-recovered assets.

Natural gas is projected to be the fastest growing component of world primary energy consumption. Its consumption worldwide is forecasted by an average of 2.3 percent annually from 2002 to 2025, compared with projected annual growth rate of 1.9 percent for oil consumption and 2.0 percent for coal consumption (*International Energy Outlook, 2005*).

From 2002 to 2025, consumption of natural gas is projected to increase by almost 70 percent, from 92 trillion cubic feet to 156 trillion cubic feet and its share of total energy consumption on a Btu basis is projected to grow from 23 percent to 25 percent (*International Energy Outlook, 2005*).

As at end 2005, proven world natural gas reserves were estimated at 6,348.1 trillion cubic feet (179.83 trillion cubic metres) which is 0.83trillion cubic metres lower than the estimate as at end 2004 (as more gas reserves are discovered overtime). At the end of 1985 total reserve was estimated at 99.54 trillion cubic metres and 143.42 trillion cubic metres in 1995 (ten years after). In general, world natural gas reserves have trended upward since the mid-1970s (BP statistical review, 2006).

Natural gas burns more cleanly than other fossil fuels. It has fewer emissions of sulphur, carbon, and nitrogen than coal or oil, and it has almost no ash particles left after burning.

1.2 PROBLEM STATEMENT AND SUBSTANTIATION

Every day natural gas flares, blaze across the swaths of Africa, Russia, Asia and the Middle East, burning off 10 billion cubic feet of energy--the equivalent of 1.7 million barrels of oil (Cook, 2004). There is absolutely more gas where that came from (See appendix 7.1 for gas flaring and consumption chart).

The natural gas which was recovered in the course of recovering petroleum (also known as associated natural gas) could not be profitably sold, and was simply burned at the oil field (known as flaring). This wasteful practice is now illegal in many countries, especially since it adds greenhouse gas pollution to the earth's atmosphere.

As with other fossil fuels, burning natural gas produces carbon dioxide, which is a greenhouse gas. Many scientists believe that increasing levels of carbon dioxide and other greenhouse gases in the earth's atmosphere are changing the global climate.

The major difficulty identified in the use of natural gas is the transportation and storage (this is linked to its properties). Unlike oil which can be easily transported, gas requires a fixed infrastructure of pipelines or liquefaction plants and specialised shipping to take it to the market.

Natural gas is four (4) times more expensive than oil to transport (California Energy Commission, 2006:2), as a result gas discovered in the course of oil exploration is burnt off by way of flaring (which is a major environmental challenge) or re-injected into the reservoir.

The development of most offshore stranded gas reserves has been limited by cost and other economic/geographic factors. Natural gas pipelines could be economical, but are almost impractical across oceans. Many existing pipelines in North America are close to reaching their capacity, prompting some politicians in colder climates to speak publicly of potential shortages (Cook, 2004).

The capital cost of pipeline for delivering Natural Gas to the market increases substantially with water depth and distance from shore. Sea bottom conditions such as a potential for mud slides can make building a pipeline too risky or too expensive.

As gas flaring restrictions increase along with the need by oil and gas producers to maximise their total reserve holdings, this trend is expected to give incentives to consider other alternatives. Companies now recognize that value for the gas may be achieved with Liquefied Natural Gas (LNG), Compressed Natural Gas (CNG), or other transportation methods to end-users.

The emergence of the Gas-to-Liquids (GTL) technology reflects growing belief in what has long been the oil industry's Holy Grail. Huge reserves of this supposed worthless remote stranded gas (*also includes associated and flared/vented gas, and gas that is re-injected purely for regulatory compliance rather than for reservoir-pressure maintenance)* can now be turned into high energy liquids using the GTL technology.

Despite these developments, the economic potential of natural gas still remains under-utilised vis-à-vis existing gas utilisation technologies due to

transportation issues. These technologies have several limitations that are directly linked to gas transportation costs. Technologies such as LNG, CNG, GTL, Gas-to-Wire (GTW) and Natural Gas Pipelining will therefore require large gas reserves to yield the expected returns.

Hence, with a large proportion of stranded gas reserves scattered in small quantities offshore, very little can be accomplished via the available technologies. Recent studies have shown that it is possible to utilise the resource by converting it to liquids at the production sites before it is transported or shipped to the market (Agee, 2005; DeLuca, 2005; Hansen, 2005; Chang, 2001; Carolan, Dyer, Minford, Barton, Peterson, Sammells, Butt, Cutler and Taylor, 2001).

These studies encouraged the development of a new concept proposed for the utilisation of offshore stranded gas. The concept involves the application of GTL technology on a floating platform. This integrated GTL plant on a floater solution is referred to as the 'Floating GTL plant'. It is believed that successful deployment of these plants offshore will put an end to offshore gas flaring and/or re-injection and eliminate the need for specialised shipping and pipelines.

However, much work still needs to be done to determine the economic viability of the proposed concept. It is also important to ascertain how the proposed concept compares to transporting gas to an onshore GTL plant via pipelines or specialised shipping.

Bearing this in mind, it is therefore necessary to develop a model that can be used as a quantitative tool to economically evaluate the floating GTL option.

The model should also be applicable in determining the economic factors that can influence the viability of the floating GTL application.

With a model like this, oil and gas companies, investors and governments could be guided in taking investment and legislative decisions in the energy sector.

1.3 THE LINK

GTL technology is a complementary rather than competitive technology for the exploitation of stranded natural gas. The process to convert natural gas directly to a hydrocarbon liquid has been understood and available since early in the 20th century (Pirog, 2004; Waddacor, 2005 and Maisonnier, 2005).

Two German chemists named Franz Fischer and Hans Tropsch developed a method of producing synthesis gas (Syngas: $CO+H_2$) from naturally occurring gas which can be used to manufacture a range of hydrocarbon liquids (diesel/ petrol) with the aid of a special catalyst (Pirog, 2004; Waddacor, 2005 and Maisonnier, 2005).

The most significant advantage of the GTL process is to produce a 'clean' hydrocarbon liquid ready to be sold into the market. The second advantage of the process is that it yields clean fuels or those that have a lower impact on the environment when burnt.

There are requirements by most industrialised nations to cut the levels of sulphur in diesel. The Fischer-Tropsch GTL process manufactures diesel with almost zero sulphur.

The Fischer-Tropsch gas-to-liquids process is fast becoming an attractive alternative to oil for major oil companies. This is due to the current increase in crude and fuel prices and concerns about the political stability of oil suppliers. GTL is also attracting the interest of energy-consuming governments, who view it as a way of reducing their energy dependence on politically unstable regions.

When the price of crude oil reached $30 a barrel, GTL became more profitable to the oil companies than liquefied natural gas (LNG). However, for much of the year 2006, prices were up to $70 a barrel. Year 2006 was the fourth consecutive year of rising crude oil prices from $32.94 per barrel in January, 2003 to $70.96 per barrel in June 2006 (See appendix 7.2A)

Today, it is believed that given the availability of a ship mounted GTL plant one could start on producing a new discovery while the economics could still be made attractive for major oil companies.

Tight capacity, extreme weather, continued conflict in the Middle East, civil strife elsewhere and growing interest in energy among financial investors led to rising crude prices which can make the Floating GTL plant option profitable and perhaps attractive. In addition, the Floating GTL plant concept can afford companies a different way of transporting gas from distant and inaccessible offshore fields that cannot be reached by pipeline.

The Floating GTL plant is movable and therefore useable for series of projects which should make it a sustainable business with an expected high return when the whole life-cycle project economics are taken into account. More so,

where the utilisation of a GTL facility allows the production of otherwise un-producible oil reserves, the combined economics can be favourable.

1.4 RESEARCH AIM AND OUTLINE

Recent studies show that the economics of natural gas synthesis on a floating platform is still being evaluated (Agee, 2005; DeLuca, 2005; Hansen, 2005; and Chang, 2001). However, with this research work, the intent is to design and develop a comprehensive mathematical model that will critically evaluate and define the economic viability of a Floating GTL plant.

To achieve the aim of this research work stated above, the following have been completed:

- A review and presentation of a comprehensive literature survey on the evolution and advances of the subject matter
- Development of a mathematical model that can be used to define the economic viability of the Floating GTL concept
- Evaluation and definition of the viability of a Floating GTL plant based on certain assumed case scenarios vis-à-vis existing technologies using the developed model, and
- Finally, testing of the model against a real life scenario, by way of validation, using an existing field data.

The result of this research work is expected to be beneficial to oil and gas companies and their stakeholders, by creating a platform for considering options for monetising Natural gas reserves and optimising production. It shall also aid Governments, legislators and/or decision makers in implementing

energy policies needed to capitalise offshore stranded gas reserves. Furthermore, this work will create openings for further research.

At the end of this study, contributions would be made to some aspects of the recent developments in the oil and gas research front. The world research in this area has been tailored in three categories, namely; Energy security, Environment, and Economy.

Energy Security research has the following objectives:

- To effectively use untapped natural gas resources, and diversify fuel resources by ensuring substitutes for crude oil
- To reduce dependence on resources from the Middle East by effectively utilizing untapped gas fields from Southeast Asia, Western Australia, Middle East and Africa
- To suppress future GTL enterprise monopolization and cost controls by major international oil companies.

Environmental impact reduction research has the following objectives:

- To promote the diffusion of highly efficient diesel powered vehicles (with low carbon dioxide gas discharge) linked to GTL light oil introduction
- To reduce and effectively use associated gases formerly flared in oil and gas producing countries

And finally, the Economic aspect of the world research has the following objectives:

- To participate in the planning of development projects and contribution to technologies through independent and superior technologies
- To promote the development of domestic gas fields in Africa and the Middle East by linking them to gas producing countries that have superior technologies.

1.4.1 RESEARCH OUTLINE

Chapter two of this work presents a literature review on the development of the Fischer Tropsch Gas-to-Liquid technology from inception. The focus is on the evolution and development of the Floating GTL technology for offshore gas reserves. However, this would not be done without a brief introduction to the history, development and present status of the GTL technology as a whole. Literatures on this natural gas monetisation option will be reviewed. Here the areas which require further research will be defined.

The third Chapter introduces the design and development of an Economic Viability (EV) Model for determining the economic viability of a floating GTL option for natural gas monetisation. It also gives a detailed description of the project methodology, as regards the quantitative analysis to demonstrate the economic viability of a Floating GTL plant.

In Chapter four, the results of the quantitative analysis carried out in the third chapter are analysed and discussed. Finally, in chapter five conclusions are made based on the results of the analyses and subsequently recommendations are made based on the conclusions drawn.

CHAPTER TWO

LITERATURE REVIEW

2.1 BACKGROUND

For several years now, the Oil and Gas Industry has been faced with the challenge of discovering natural gas when looking for oil. This is most common with offshore exploration and production activities. The main reason already discussed, is because natural gas is difficult to monetise due to transportation issues, and when associated with an oil discovery, coning problems can make the find almost un-producible. Coning problems refers to a situation where the gas forms cones around the oil and obstructs oil flow.

However, technological advances in organic chemistry, electrochemistry, intelligent systems, robotic and sensors, and advanced materials will continue to open opportunities for gas development. This has been the case for the advances enjoyed in gas-to-liquids technology today.

Rivero and Nakagawa (2005:1) attributed the recent growth in offshore oil and gas activities to the current trend of Fossil fuel sources location which is towards remote offshore locations, deeper water fields and complex geological environments.

A recent review for prospects discussed by Rivero and Nakagawa (2005:1) shows that there are more than 250 new offshore developments. 80% of these developments are in shallow waters (as a consequence of small reservoirs in largely exploited areas) and 20% in new large fields in deep and ultra deep waters.

Presently, pipelines are used to transport the largest volume of Natural gas to market. It is then sold to end users for industrial, commercial or residential applications. However, this option requires large capital investments. Also, there are limited areas where this market is large. This has been especially true in oil dominated hot spots of the world, like West Africa, the Middle East and the Gulf of Mexico.

Gas risk has caused long stretches of coastlines to remain relatively unexplored, which in turn has caused major oil discoveries to be left un-drilled. According to DeLuca (2005) the most notable example of this is the 1.3 billion barrel Zafiro field off Equatorial Guinea, where companies such as Conoco, BP and Statoil pulled out of a project prior to the first well because it was thought to be too gas prone.

As a result of this preference for oil, much of West Africa remains a massive virtually untapped gas field. DeLuca (2005:38) mentioned that in Nigeria alone, the government cites a gas reserve of between 170 and 200 trillion cubic feet, of which 120 trillion cubic feet is proven and uncommitted.

In addition, as much as 90 percent of the discovered oil reservoirs in Nigeria are estimated to be gas prone. While the solution seems to lend itself well to a Liquefied Natural Gas (LNG) exploitation strategy, the logistics of gathering to a central point is almost impossible. This is due to the fact that the reserves are scattered offshore in several one to three trillion cubic feet deposits among hundreds of fields in the highly fragmented Niger Delta region of Nigeria (Agee, 2005).

With the exception of a few large concentrations, such as the case for Shell's Bonny LNG plant, much of the country's offshore gas resources are either re-injected or part of the estimated 2 billion cubic feet that is flared daily. The estimated 2 billion cubit feet of natural gas flared daily in Nigeria is what makes the country the highest gas flaring country in the world (ERA, 2005:4).

The problems identified above (i.e. re-injection and flaring) associated with oil exploration offshore are also common in some parts of the Middle East, Australia and Europe.

Hence, to monetise such offshore stranded gas resource a low cost solution is necessary. A good approach might be to convert the gas into high energy liquids using the three-stage Fischer Tropsch (FT) GTL process at production sites before transportation.

The application of the FT-GTL technology offshore on a Floating Production Storage and Offloading (FPSO) facility is indeed a very interesting and productive way of converting stranded and/or associated natural gas into high energy liquids on a ship.

However, to implement the Fischer-Tropsch (FT) GTL technology offshore in a cost effective manner, the following issues have to be addressed:

- the possibility of getting the GTL processing plant to the remote locations offshore, where the gas resource is being produced with respect to the technical challenges, safety considerations and other limiting factors, and
- the economic viability of such a venture

2.2 WHY GTL?

There are several options for monetising stranded natural gas reserves and most are smaller versions of existing technology, such as compressed natural gas, liquefied natural gas, methanol and GTL. However, all of these potential solutions have advantages and disadvantages.

The Fischer-Tropsch process, the basis for all GTL technology, is used to convert remote natural gas into clean diesel fuel. This fuel can be used as a blended stock to upgrade conventional petroleum diesel fuels and extended diesel fuel capacities and supplies (Abdul-Rahman and Al-Maslamani, 2004).

GTL fuel offers a new opportunity to use non-petroleum-based fuels in diesel engines without compromising fuel efficiency, increasing capital outlay, or impacting infrastructure cost (Abdul-Rahman and Al-Maslamani, 2004:1)

GTL fuel has virtually no sulphur, aromatics, or toxics (Ahmad, Zughaid and El-Arafi, 2002:4-5; Abdul-Rahman and Al-Maslamani, 2004:3). It can be blended with non-complying diesel fuel to make the fuel cleaner so it will comply with new fuel standards.

The distinct advantage of GTL is that products can be stored, handled, shipped and eventually marketed by established methods. Hence, gas discoveries offshore can be explored and converted into high energy liquid fuels using the FT-GTL technology onsite before transporting it.

2.3 HISTORY OF FT-GTL

Apanel (2005:1) wrote that catalysts for the Fischer Tropsch Synthesis were first developed in the early 1900s. This was following the discovery by

Sabatier and Senderens in 1902 that CO (carbon monoxide) could be hydrogenated over Cobalt, Iron and Nickel catalysts to methane.

Thackeray (2000:2) credits the origin of the FT process to the report made by Badische Anilin and Soda Fabrik in 1913 that under high pressures, mixtures of higher hydrocarbons and oxygenated compounds (liquids) could be produced catalytically from carbon monoxide and hydrogen.

On a contrary opinion, Arianto and Siallagan (2000:1), Steynberg and Dry (2004), Pirog (2004:4), Waddacor (2005:1) and Maisonnier (2005:1) credit the origin of the FT process to a vision realised by two chemists in Germany, Franz Fischer and his Czech-born partner, Hans Tropsch, who developed the unique chemical process to produce synthetic fuels (synfuels) from coal in the 1920s.

The feedstock for all the FT process was primarily coal. The process was put into commercial operation for the first time in Germany in 1936 (Thackeray, 2000; Steynberg & Dry, 2004 and Waddacor, 2005).

However, the technology did spread to several industrial nations, including the UK, France, the US, Japan and China, during the 1930s and 1940s. The primary motivation during that period was to strengthen security of energy supply, especially in times of war and political uncertainty (Waddacor, 2005).

During the Second World War the technology played an important role in providing transportation fuel for the German war effort. This was as a result of their insufficient access to crude oil resources at that time (Maisonnier, 2005; Apanel, 2005; and Arianto & Siallagan, 2000).

After the war, the next application came in 1955, when Ruhrchemie and Lurgi of Germany and Kellogg Company of the United States led the commissioning of the first commercial coal based FT plant in South Africa (Maisonnier, 2005). At this time, South Africa was under specific political circumstances which led the Government to undertake a massive program for the production of motor fuels from coal.

The first FT unit using natural gas was opened in 1991 by Mossgas (now PetroSA). By 1993, Shell started operating a 14,500 barrels per day GTL unit in Bintulu, Malaysia, based on research on the Shell gasification process conducted in the fifties (Maisonnier, 2005).

Today, South Africa leads the world in the use of synthetic fuels. During the last five decades, South Africa has built four synfuels plants, all government funded, producing approximately 150,000 b/d of synthetic fuels and chemicals (Arianto & Siallagan, 2000).

Declining GTL production costs (as a result of better catalysts, scale up and plant design), growing worldwide diesel demand, high oil prices, stringent diesel exhaust emission standards, fuel specifications and, the need to monetise the abundant gas resource in the world are factors driving the Petroleum Industry to revisit the GTL process for producing higher quality fuels.

Since the late 1990's, major oil companies including ARCO, BP, Conoco Phillips, Exxon Mobil, Statoil, Sasol, Syntroleum, SasolChevron, Shell and Texaco have announced plans to build GTL plants to produce fuel.

The major players in the FT-GTL technology advancement includes but are not limited to BP, ExxonMobil, Syntroleum, Rentech, Global Process Systems, Sasol, SasolChevron, Conoco Phillips, Statoil, ChevronTexaco, Qatar Petroleum, PetroSA, Shell, Foster Wheeler, Haldor Topsoe, Stone Webster, Engelhard and Conoco Philips.

2.4 THE INTEGRATED THREE STEP GTL PROCESS

The significant FT-GTL conversion technology is generally believed to feature an integrated three-step process that can be simplified thus:

- The conversion of natural gas, or another methane-rich feedstock, through reforming into synthesis gas (Syngas), a predetermined mixture of hydrogen and carbon monoxide in a ratio of about 2:1
- The synthesis of the Syngas obtained in the first step through the Fischer-Tropsch process itself. This converts the synthesis gas into paraffinic hydrocarbons in the form of a synthetic version of crude oil (Syncrude).
- The upgrading and conversion of the subsequent Syngas-derived liquid hydrocarbon into a specific slate of liquid fuels and/or petrochemical products or intermediates, according to predetermined suite of refining plants and the preferred process of selectivity. (Thackeray, 2000; Dybkjær & Christensen, 2001; Steynberg & Dry 2004; Waddacor, 2005)

The three step process can be summarised in the following diagram:

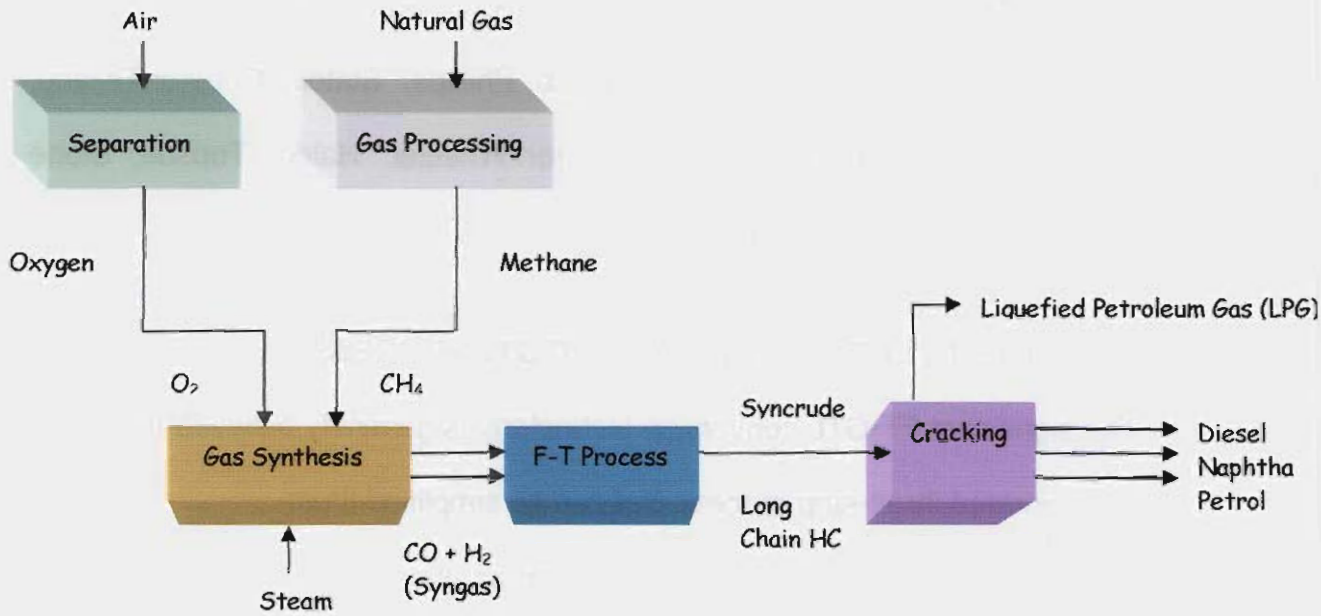

Figure 2.1: The Fischer-Tropsch Gas-to-Liquid Chemistry
Source: Schlumberger Oilfield Review, Autumn 2003.

2.4.1 SYNTHESIS GAS GENERATION

To produce synthesis gas (Syngas), oxygen is added to the sulphur free natural gas feedstock, in a process which combines the oxygen with the carbon in the natural gas to yield carbon monoxide and hydrogen.

Thackeray (2000) highlighted four alternative basic methods developed to produce Syngas. They are:

1. Steam reforming of the feedstock in the presence of a catalyst
2. Partial oxidation, whereby oxygen is separated from nitrogen in a cryogenic air separation unit and burned together with natural gas at high temperatures and pressures. Alternatively, air maybe used instead of pure oxygen.
3. Autothermal reforming, which involves partial oxidation coupled with steam reforming, see figure 2.2

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

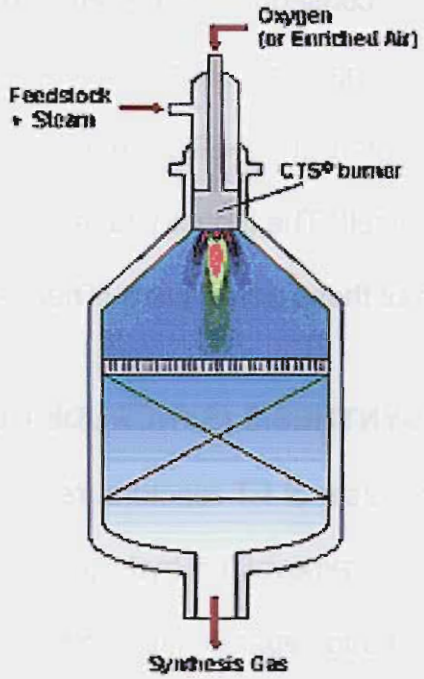

Figure 2.2: Pictorial view of the Autothermal Reformer
Source: www.topsoe.com (retrieved on the 10th of November, 2006)

Basini and Piovesan (1998) compared economic evaluations of steam-CO_2 reforming, autothermal reforming, and combined reforming processes. They concluded that combined reforming has the lowest production and investment costs at a H2/CO ratio of 2.

Another method being looked into is the 'New ceramic membranes' which might become interesting for significant cost reduction of synthesis gas production by 30%-50% (Udovich, 1998:418).

The aim of the ceramic membrane technology is to develop methods to supply pure oxygen to mix with natural gas in the production of synthesis gas. Success in this development will eliminate the need for an Air Separation Unit (ASU), which in most existing synthesis gas processes, accounts for around 20% of the overall costs of an FT-GTL plant (Thackeray, 2000).

An important feature will be the consequent large reduction in the weight and footprint (area) of the synthesis gas unit. This will make it ideal for offshore applications or for the construction of FT-GTL plants in regions such as the Artic, where construction is difficult. The industry funded team is looking for at least a 25% reduction in each of these parameters (Thackeray 2000:6).

2.4.2 FISCHER-TROPSCH SYNTHESIS (SYNCRUDE GENERATION)

The Fischer-Tropsch stage consists of FT reactors, recycle and compression of unconverted synthesis gas, removal of hydrogen and carbon dioxide, reforming of methane produced and separation of the FT products.

The most important aspects for development of commercial Fischer-Tropsch reactors are the high reaction heats and the large number of products with varying vapour pressures (gas, liquid, and solid hydrocarbons).

Thackeray (2000) and Steynberg & Dry (2004) identified four main reactors which have been proposed and developed after 1950:

1) Three-phase fluidized (Ebulliating) bed reactors or slurry bubble column reactors with internal cooling tubes. Examples of this type of reactors are the Sasol Slurry-Phase Distillate (SSPD) reactor, Energy International's GasCat reactor and Exxon's AGC-21 reactor.

2) The Multitubular fixed bed reactor with internal cooling. Examples of this type of reactors are the Sasol Arge reactors and Shell Middle Distillate Synthesis (SMDS) reactors.

3) Circulating Fluidized bed reactor with circulating solids, gas recycle and cooling in the gas/solid recirculation loop. An example is the Sasol's Synthol reactor.

4) Fluidized bed reactors with internal cooling. An example is the SAS reactor in Sasol.

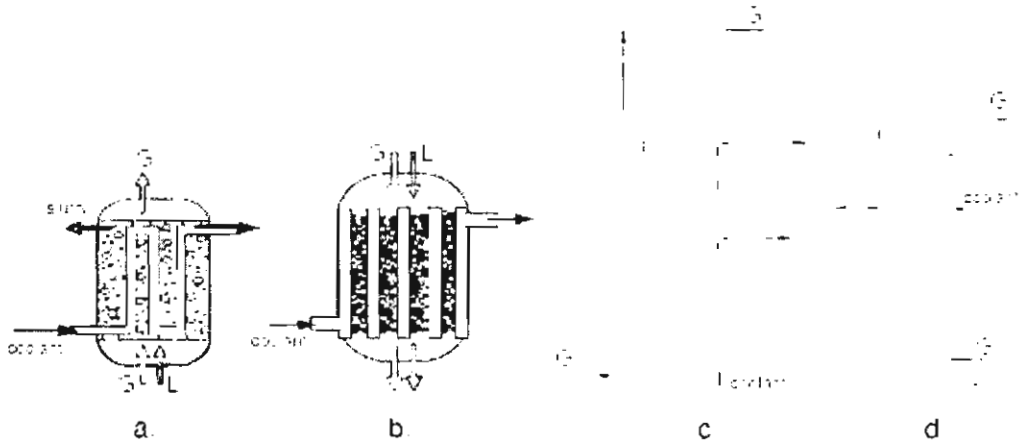

Figure 2.3: Possible reactors for FT synthesis. a. Slurry bubble column reactor; b. Multitubular trickle bed reactor; c. Circulating Fluidized bed reactor; d. Fluidized bed reactor.
Source: Sie (1998)

Thackeray (2000:11) stressed that the catalyst employed in the Fischer-Tropsch process is of crucial importance.

Sie (1998:134) compared the advantages and disadvantages of the two most favourite reactor systems of the four described above for the Fischer-Tropsch synthesis of high molecular weight products. The Multitubular fixed bed reactor and the slurry bubble column reactor. He identified the major drawbacks of the bubble column to be the requirements for continuous separation between catalyst and liquid products.

However, the advantages are low pressure drop over the reactor, excellent heat transfer, no diffusion limitations and the continuous refreshment of

catalyst particles. He likened the main disadvantage of the Multitubular reactor to the high costs of tubes ranging from 10 to 100,000 typical for commercial scale.

Jager (1998:119) concluded that the cost of a single 10,000BPD slurry reactor system is about 25% of that of a tubular fixed bed reactor. This can be foreseen as a driver for the continuous technology improvement of the slurry reactor systems.

2.4.3 PRODUCT UPGRADING

The third step of an FT-GTL process is upgrading of the subsequent Syngas-derived liquid hydrocarbons into a specific slate of liquid fuels and/or petrochemical products or intermediates, according to a predetermined suite of refining plants and the preferred process of selectivity. Depending on the process used, the products slate obtained can vary widely.

The key feature of the FT-GTL fuel product is its potentially high yield of high cetane, low-emission diesel oil (Thackeray 2000:14). The fuel is free of sulphur and heavy metals and also causes fewer emissions. According to automotive group DaimlerChrysler, GTL will become part and parcel of every filling station beginning as early as 2010.

2.5 PIPELINING AS AN OPTION FOR OFFSHORE RESERVES

For onshore and near shore gas, pipeline is an appropriate option for transporting natural gas to market. However, as the transporting distance to shore and water depth increase, it becomes un-economic (Chang 2001:1).

Large diameter and long distance pipelines have been known to imply high capital investments. This is because they require large high-value markets and substantial proven reserves to be economically viable.

Cornot-Gandolphe, Appert, Dickel, Chabrelie and Rojey (2003:7) reported that capital charges typically make up at least 90% of the cost of transmission pipelines. They identified the key determinants of pipeline construction cost as: diameter, operating pressures, distance and terrain. Other factors include climate, labour cost, degree of competition among contracting companies, safety regulations, population density and rights of way. These factors may cause construction to vary significantly from one region to another.

Pipeline operating costs vary mainly according to the number of compressor stations. Compressor stations require significant amounts of fuel, and local economic conditions, especially labour cost, to keep them operational (Cornot-Gandolphe et al. 2003:7).

Offshore natural gas can be transported to onshore market by constructed pipelines. However, this option requires a lot of capital and huge proved gas reserves. Chang (2001:1) wrote that typical offshore pipeline installation costs range from $170,000/mile to $1,000,000/mile.

On the other hand, Subero, Sun, Deshpande, McLaughlin and Economides (2004:4) claimed that a common industry estimate for sub-sea pipeline installation CAPEX range from $500,000/mile to $1,000,000/mile. They stated that the range may be greater when larger ranges of rates are considered.

However, approximately 1% of the gas volume per 1000km shipping distance per year is used as fuel gas and debited as the shipping cost.

Also, in offshore area, pipeline operational problems such as the formation of gas condensates and hydrate deposition often occur. This non-gaseous phase events could partially or totally block gas flow through the pipelines (Chang, 2001:2; Subero et al., 2004:2).

The developments over the past decade in offshore pipeline technology have contributed to lower unit costs and made deep water projects possible. Cornot-Gandolphe et al. (2003:7) recognised two methods commonly used to install marine pipelines. These are the S-lay and the J-lay methods.

The S-lay method is the traditional method for installing offshore pipelines in relatively shallow water. The method is so-named because the profile of the pipe as it moves in a horizontal plane from the welding and inspection stations on the lay barge and unto the ocean floor forms an elongated "S". On the other hand, the J-lay method is a comparatively new method for installing offshore pipelines in deeper water. The method is so-named because the configuration of the pipe as it is being assembled resembles a "J".

Cornot-Gandolphe et al. (2003) pointed out that the J-lay method is a main alternative to the S-lay method for larger diameter pipelines. The J-lay method is also preferred in deeper water applications, mainly because when the water depth becomes deep, the required force to hold the vessel in-place during an S-lay operation becomes too great. Here the pipeline is welded together in a vertical position, and lowered down to the seabed in a J shape.

The J-lay method is inherently slower than the S-lay method and is therefore more costly. An example of the J-lay method is its application in the construction of the $3.2 billion Blue Stream Project, designed to deliver Russian gas across the black sea to Turkey (Cornot-Gandolphe et al., 2003:7)

The high cost associated with this gas monetisation option has been proven not to support small stranded gas reserves and associated gases that are too far from the market (Chang 2001). An example is the Meren 1 field offshore Nigeria where associated gas produced alongside crude oil is being flared because the quantity produced is considered insufficient for the construction of a pipeline to take the gas to the nearest gas tie-in that leads to the nearest LNG facility.

However, in the fourth chapter, this research work will try to quantitatively examine the possibility and subsequently the economic viability of implementing the offshore Floating GTL technology in situations as those described above.

2.6 OFFSHORE ADVANCES IN FT-GTL TECHNOLOGY

With over 25% of world gas reserves located offshore, the conversion of natural gas to synthesis fuels using the Fischer-Tropsch technology to produce white crude/fuels at the offshore locations offers an alternative to flaring, re-injection, or LNG production (Gradassi, 1995:42; Jager 1998; Hutton, 2003).

The increasing environmental constraints in the developed world are leading to close study of the application of the FT process offshore. In Particular, the

operation of a Fischer-Tropsch unit on board a ship/barge (Floating Production Storage and Offloading vessel) is a very interesting and productive way of converting usually flared gas into clean, synthetic crude. The syncrude can be mixed with the regular crude oil in the ships' tanks.

Alternatively, for stranded gas reserves, the gas can be processed using the three step FT technology to produce high energy, low sulphur synthetic fuels. Producers could also earn valuable carbon credits by extinguishing flared gas. In the longer term, offshore FT-GTL plants could reduce costs even more and make the development of some small and remote gas reserves or deep offshore gas feasible. This technology has the potential to reduce cost by minimising the costs of offshore platforms and pipelines, eliminating the need for port facilities and reducing the time needed to build the plant.

Construction can be carried out in a low-cost location and the vessel transported to the production zone. Offshore FT-GTL plants can also address problems that arise when siting facilities onshore. Investors may see them as less politically risky ventures in some countries.

However, a number of technical, social, safety and economic issues have to be addressed before the technology can be deployed commercially.

2.6.1 FLOATING PRODUCTION, STORAGE AND OFFLOADING VESSEL

A question in the mind of people new to the offshore concept is that, "Is it possible to have a processing unit offshore?" The answer is 'yes' and this brings us to the introduction of "A Floating Production, Storage and Offloading vessel" (FPSO; also called a unit and a system). It is a type of floating tank

system used by the offshore oil and gas industry designed to take all of the oil or gas produced from a nearby platform (s), process it, and store it until the oil or gas can be offloaded onto waiting tankers, or sent through a pipeline (Microsoft Encarta Encyclopedia, 2005).

A Floating Storage and Offloading Vessel (FSO) is a similar system, but without the possibility to do any processing of the oil or gas. Oil is accumulated in the FPSO until there is sufficient amount to fill a transport tanker at which point the transport tanker connects to the stern of the floating storage unit and offloads the oil. An FPSO has the capability to carry out some form of oil separation process obviating the need for such facilities to be located on an oil platform. This is represented diagrammatically in figure 2.3.

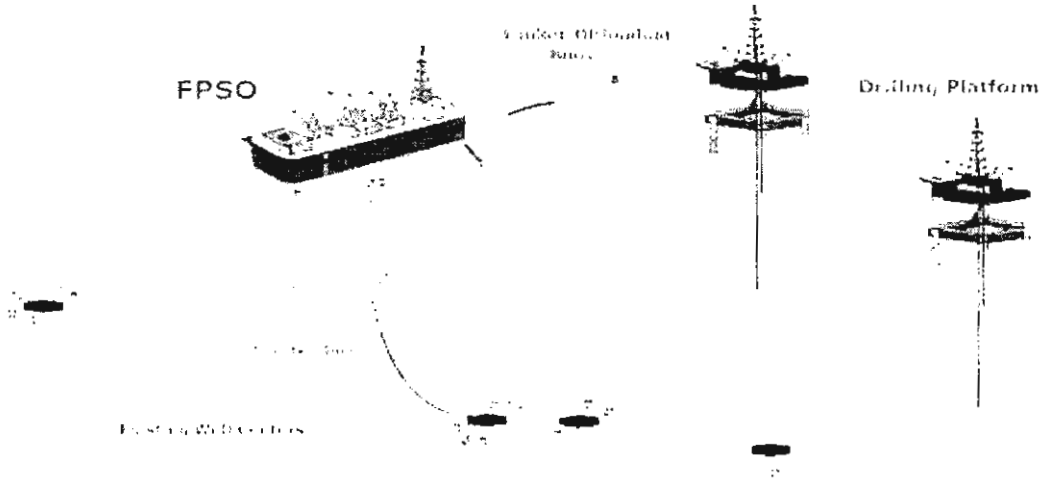

Figure 2.4: Diagrammatic representation of a FPSO
Source: Microsoft Encarta Encyclopaedia 2005

FPSO's are particularly effective in remote or deepwater locations where seabed pipelines are not cost effective. The world's largest FPSO is the Kizomba A. It has a storage capacity of 2.2 million barrels. It was built at a cost of over US$800 million by Hyundai Heavy Industries in Ulsan, Korea. It is operated by Esso Exploration Angola (ExxonMobil). It is located in 1200

metres (3,940 ft) of water at deepwater block 15,200 statute miles (320 km) offshore in the Atlantic Ocean from Angola, West Africa. It weighs 81,000 tonnes, it is 285 metres long, 63 metres wide, and 32 metres high (Wikipedia 2006).

Recent research and developments have also proved that the FPSO units can be designed to accommodate GTL processing plants. This will be demonstrated in the course of this research work.

2.6.2 CHALLENGES OF OFFSHORE DEPLOYMENT OF GTL PLANTS

In order to achieve a successful integration of GTL plants to Floating Production Storage and Offloading (FPSO) units, a number of issues have to be addressed.

2.6.2.1 Technological Challenges

Verghese (2003:6-7) stated that the deployment of GTL equipment systems offshore and their marinization (marinization implies movement to a marine environment) poses several challenges. He continued by writing that the GTL flow scheme introduces a major set of new unit operations to a prospective FPSO. The technological challenges are as follows:

- ***Systems Simplification***: Equipments and systems have to be critically reviewed to reduce the size of units.
- ***Marinization***: For gas conversion processes, the impact of salt carrying air on reactor systems and metallurgy (especially under high pressure conditions have to be evaluated. Also, the impact of motion on the mechanical design and process performance require in-depth evaluation.

- ***Process Control***: The level of sophistication of process control and process surveillance needs to be enhanced. This is necessary due to the relative complexities of gas conversion technologies.
- ***Process Conditions***: The high temperatures and pressures associated with gas conversion is an issue that also needs careful evaluation.
- ***Coupling with Exploration and Production Operations***: The system has to be robustly designed to handle higher frequency of shut downs and start-ups, and must have the flexibility to respond to changes in fluid rates and compositions.
- ***Constructability***: One of the merits of FPSO deployment is the ability for equipments and systems integration to be carried out in shipyards. But the integration of such equipments (having their individual weight and size) can pose a challenge on safety.

2.6.3 SYNTROLEUM'S OFFSHORE GTL ADVANCES

Syntroleum has been working on the concept of Offshore GTL processing for a number of years and has put together an experienced team to bring the ideas to reality. Syntroleum Corporation is the developer, user and licenser of the proprietary Syntroleum® Process, which converts natural gas into ultra-clean liquid hydrocarbons, such as diesel and naphtha (Hutton, 2003).

Waddacor (2005) stated that Syntroleum developed its first working GTL process in 1985 using a bench-scale reactor, with its first patents issued in 1989 and 1990. He further stated that Commercial marketing efforts for the Syntroleum process began in 1993. The company recently updated its GTL

commercialisation strategy by reducing the importance of licensing and focusing on partnering with upstream producers in developing stranded gas reserves in the 1 to 3 trillion cubic feet range.

Hutton (2003) believes that taking the FT-GTL process offshore is one technological challenge that no company can take on its own. He pointed out that Syntroleum has been working with potential clients from the oil and gas industry and other players; like the United States Department of Defence (DoD) and most recently, commercial designers to develop marine-based GTL technology using air-based process. The design effort has developed deployable GTL barge and GTL FPSO technologies.

Syntroleum's air-based technology enables the targeting of gas reserves in the range of 1 to 3 trillion cubic feet of more. These are reserves that are too small for LNG projects or world scale GTL projects. Syntroleum has identified and is investigating more than 20 potential projects (Agee, 2005).

2.6.3.1 Syntroleum's GTL Process

The Syntroleum GTL process consists of three fundamental steps. Firstly, Natural gas, steam and air are mixed in the correct proportion in a fixed-bed catalytic reactor (reformer) to produce Syngas. In the following step, the reaction gas (Syngas), consisting primarily of carbon monoxide and hydrogen is processed in a slurry bubble FT reactor to create a wide ranging paraffinic hydrocarbon product (synthetic crude, or syncrude).

Finally, the syncrude is refined using the conventional refinery processes to produce ultra-clean diesel, naphtha and lube oils for commercial markets.

2.6.3.2 The Syntroleum GTL Barge

The GTL Barge was the first commercial marine-based GTL design by Syntroleum. It is intended for use in calm, shallow-water environments (such as rivers, estuarine or coastal bays).

It has a process capacity of 175 million cubic feet per day (MM cf/d) of untreated natural gas. LPGs (Liquefied Petroleum Gases) are firstly removed from the natural gas before it is processed using the GTL technology to convert it to liquid product (Agee, 2005).

The barges hull measures 75 metres by 140 metres, with a usable deck space of around 10,000 square metres. Onboard process facilities include gas dehydration, LPG recovery, FT syncrude production and a refinery to upgrade the syncrude to naphtha and diesel. The total topsides facilities weight is estimated at 28,500 tonnes, including of 1st catalyst fills and inventories. There are 258 major pieces of equipment on the facility. The barge is self contained with all required utilities and quarters for about 60 personnel (Marcotte, 2005; DeLuca, 2005).

The GTL Barge could revolutionize the way oil and gas companies deal with gas. It will allow them book for 1 to 3 TCF (representing 100 – 300 million barrels of liquid products) with minimal geological risks. The Barge would produce these reserves over a 20-year life, reducing the uncertainty of future production levels (Agee, 2005; DeLuca, 2005).

2.6.3.3 Syntroleum GTL FPSO

Syntroleum began the development of a GTL FPSO in 2001, following an award from the DoD (US Defence Department). The company was contracted to develop a design with operating characteristics that would allow the vessel and process facilities to operate up to sea state three (Agee, 2005; Marcotte, 2005; Hutton, 2003). Sea state three in this context is an indication of the level of sea disturbances.

The DoD envisioned the deployment of GTL FPSOs close to military frontlines. This will enable the production of liquid fuels that meet strict military standards from existing natural gas reserves or gas delivery from LNG tankers (Agee, 2005; Marcotte, 2005; and Hutton, 2003).

The design which meets the DoD strict technical requirements was completed in September 2003. It has a nominal 13,400 barrel a day capacity for producing military specification Jet fuel. The facility is 55 metres by 265 metres, with a topsides weight of 32,000 tonnes (Agee, 2005; Marcotte, 2005).

Furthermore, Agee (2005) also stated that in evaluating deep-water options, two alternative options became apparent. Both options utilise conventional FPSOs supporting GTL process equipment. Option 1 primarily considers the oil and gas processing on separate vessels, while option 2 considers primary separation and GTL processing combined on the same vessel.

Syntroleum is looking to start exploration activities on the Aje field, located offshore Western Nigeria. This will be the first commercial opportunity for the

company to use its GTL Barge and FPSO technology. However, the company is still working out the economics of the venture (Guegel 2005, DeLuca 2005).

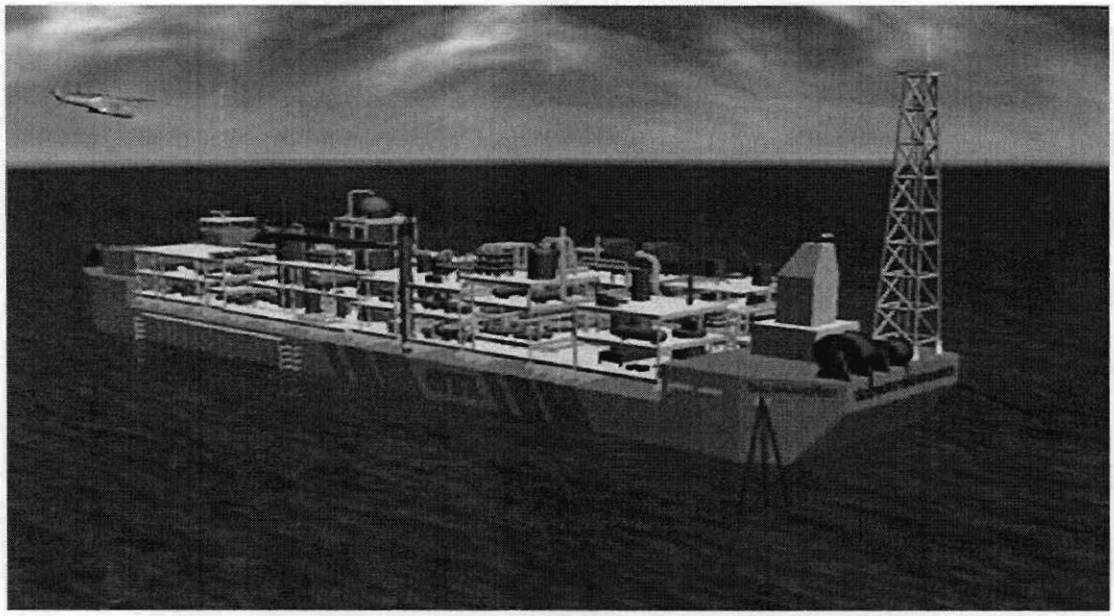

Figure 2.5: Syntroleum GTL FPSO design
Source: www.syntroleum.com (April 2006)

2.6.4 STATOIL'S OFFSHORE GTL EXPERIENCE

Statoil's GTL research started around 1985. But, their offshore GTL study started in 1999 and it was based on the fact that flaring of gas had become an environmental issue for both authorities and oil companies (Olsvik 2005). This created a need for converting offshore natural gas to transportable products at the locations where the gas is produced without using pipeline infrastructures.

As a result of the investigation, two GTL syncrude concepts were studied:

1. A combined FPSO for small fields processing the entire well stream with conversion of gas to about 4300 b/d synthetic hydrocarbons.
2. A dedicated floater receiving gas from a large FPSO with a 14,500 b/d syncrude plant onboard (Olsvik, 2005:4; Hansen, 2005:6).

However, the GTL plants were designed as self supporting entities with a minimum level of integration with the ship systems. The design conditions were based on the environmental conditions at the Asgard field at Haltenbanken in the Norwegian Sea.

The ship and topsides are designed to remain structurally intact for about 100 years storm conditions with significant wave height of 15.7 metres. The equipments according to the design specifications are located such that the vessel motions have little or no effect on them (Olsvik, 2005:5).

Statoil adopted the Sasol Slurry Phase Distillate technology (SSPD) for the offshore GTL design. The process steps for the offshore plant are as follows:

- Cryogenic oxygen production (ASU)
- Synthesis Gas Production by Autothermal Reforming (ATR): already discussed and the
- Slurry Phase Fischer-Tropsch synthesis: already discussed

In the Cryogenic Oxygen Production (ASU), air is compressed, cleaned and cooled to cryogenic temperatures, where it is distilled in a double column arrangement to produce a low pressure oxygen product. Oxygen produced is then pressurized either by using a compressor or a pump.

The traditional cryogenic Air Separation Unit (ASU) can avoid oxygen compression by producing liquid oxygen at low pressure and pumping this liquid to the pressure required for downstream service. This cycle (with vaporisation) is the recommended route for providing large quantities of oxygen at sea (Parmaliana, Sanfilippo, Frusteri, Vaccari & Arena, 1998:848).

The main challenges for large ASU's on ships relate to the design and operation of such plants to maintain production under the swaying motion experienced on board a ship located in open sea, especially the special safety features required for an application involving fuel, oxidant, ignition sources and personnel in close proximity (Parmaliana et. al., 1998:848).

The process selection criteria for the offshore conditions were safety, compactness, low weight, simplicity of operations, robustness of motion and minimum maintenance requirements. The construction approach adopted by the company is similar to that of the North Sea FPSOs (Olsvik, 2005; Hansen, 2005).

The Statoil group came up with the following conclusion based on their offshore GTL investigation:

- Offshore application of the GTL processes is technically feasible
- It can be built within Statoil's stringent safety requirements
- The gas cost in areas with pipeline access to West-European market is too high for offshore Floating GTL
- Offshore GTL can be profitable for associated gas without marked outlet

2.6.5 ENERGY INTERNATIONAL'S OFFSHORE GTL STUDY

Energy International (EI) is a leader in catalyst and process development as it relates to Fischer-Tropsch (F-T) technology. Through this activity, they developed a concept for a technique for capturing the fuel value in the associated natural gas contained in crude oil.

In the concept, dissolved natural gas would be processed via F-T technology to produce light hydrocarbons that would then, in one manifestation of this concept, be re-dissolved in the crude oil to produce a lighter crude than the original, containing all of the natural gas, but with the vapour pressure of the crude lowered to an acceptable level via the conversion process (Singleton and Cooper, 1997:1).

This technique, according to Singleton and Cooper would be of particular interest in those instances where the alternative methods of collecting and utilizing the associated natural gas were expensive. A study of the application of this technology was undertaken by EI with support from the United States Department of Energy (US-DOE).

EI asserted that an offshore F-T plant can best be accommodated by a FPSO (Floating Production, Storage, Off-loading vessel) based on a converted surplus tanker. The combination of an F-T plant with a FPSO was referred to as a FFTP (Floating Fischer-Tropsch Production system) by EI (Singleton and Cooper, 1997:2).

The case considered was the installation of a Fischer-Tropsch plant on an FPSO capable of handling 56,000,000 cubit feet per day of wet associated gas derived from 22,400 bbl/d of crude (a Gas-Oil Ratio (GOR) of 2,500). The FPSO would be a converted 200,000 DWT (Dead Weight) VLCC tanker costing $137 MM including $65 MM for synthetic line mooring and associated vessel facilities. The F-T plant would produce 25,000 bbl/day of premium

quality synthetic crude, and would have a capital cost of $383 MM (Singleton and Cooper, 1997:2).

According to Singleton and Cooper (1997:2) a major oil and gas company which is a Developer of deepwater gas/oil projects and a deep water Gulf of Mexico tract lease-holder also participated in the study on an anonymous basis.

The Developer concluded his assessment as follows:

- "In summary, if the Fisher-Tropsch process field-scale application will perform somewhat similarly to the representations made by EI, it appears that commercial interest in the F-T process/shuttle tanker development methodology is merited
- Consideration of other scenarios such as field development and delineation, or production of small fields shows that the FFTP may have merit in these also, partly due to being able to move the entire facility to a new location easily.
- Compared to methanol, F-T products have a much larger market, and can be handled and processed by existing petroleum systems if desired. FFTP is probably more adaptable to the offshore than LNG, and will be practical at lower production rates".

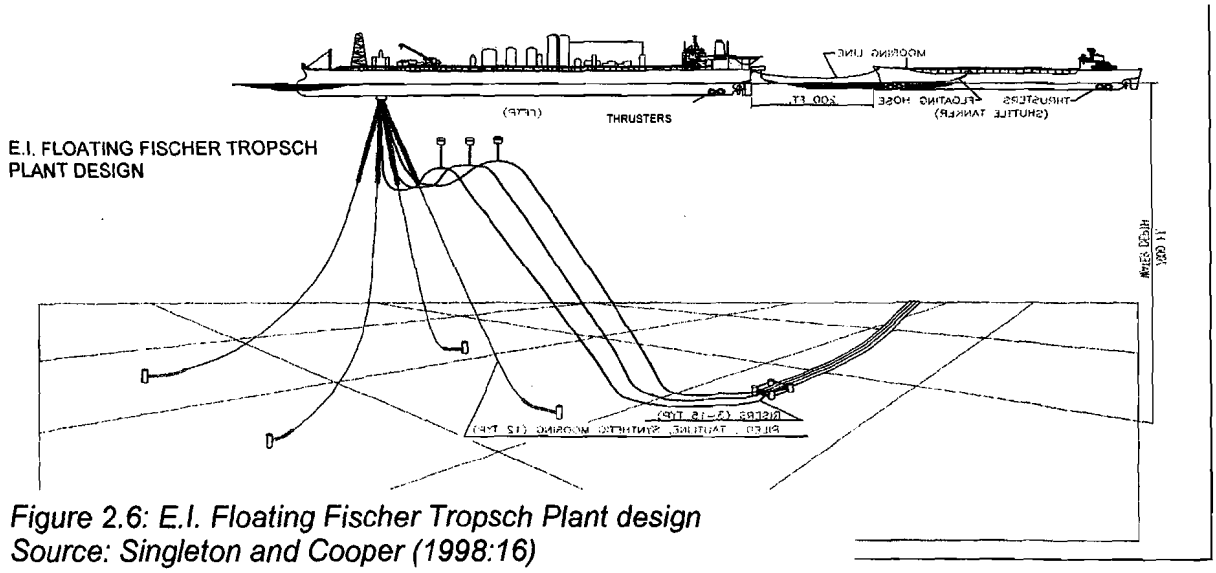

Figure 2.6: E.I. Floating Fischer Tropsch Plant design
Source: Singleton and Cooper (1998:16)

2.6.6 OFFSHORE SAFETY AND ENVIRONMENTAL CONSIDERATIONS

Safety and environmental impact issues have been identified as a prime consideration in the design of an offshore gas conversion facility. Some key areas of safety and environmental impacts associated with the deployment of the technology offshore have to be systematically analysed.

According to Agee (2005), a major advantage of the Syntroleum offshore process is that it does not use pure oxygen. He believes that when adding new processes offshore, everything should be done to minimise hazards, and that oxygen plants would add unnecessary complications offshore.

Meanwhile, Statoil identified internal explosion due to contamination, cryogenic leaks (clouds) and spills, and metal fire as the main offshore cryogenic oxygen production (ASU) safety hazards. They took the following risk prevention measures: spill collection, contamination barriers, liquid oxygen pumping, good layout philosophy, process design, and detection systems for avoiding build up of contaminants in the ASU (Olsvik, 2005:15).

Typical maximum operating pressures in the Syntroleum process are only 400psi. The maximum operating temperature is around 1,700 deg F at the outlet of the advanced thermal reactor (ATR). This is contained with ceramic-lined vessels and piping and is quickly quenched on exit (Agee, 2005). These conditions are not excessive compared with others found offshore and they do not require specialized materials.

For years, the operation of reactors utilising advanced catalysts has been established in refining and other onshore industries. However, operating this type of equipment offshore will bring its own challenges. Hutton (2003) explained that some concerns have been expressed about catalyst handling offshore.

He claimed that the catalysts used in the Syntroleum process are proprietary and regeneration of the FT catalyst will be possible on-site. Spent Catalyst will be replaced and returned for reprocessing, or disposed of in an environmentally friendly manner. However, research into Statoil's Offshore GTL studies did not show how they plan to handle catalysts used in the process on-site.

According to Olsvik (2005), Statoil adopted the CRA (Coarse Risk Assessment) based on the Norwegian Petroleum Directorate (NPD) and their safety requirements. This involved:

- Identification of all hazards associated with the operation of the Offshore GTL plant
- Estimation of the contribution of these hazards to both personnel risk and impaired frequencies of the safety functions, and

- The identification and incorporation of risk reducing and preventive measures.

Olsvik (2005:12) added that the CRA was also incorporated with the use of the FAR (Fatal Accident Rate), which is a measure of the risk to personnel onboard the vessel. It is defined as:

$$\frac{\text{(Potential loss of lives per year)} * 10^8}{\text{(Number of persons on the floater)*(Exposure time per person per year)}}$$

The FAR for the combined GTL-FPSO was done for the following identified hazards: Topside fire and explosion, Topside toxic leaks, Cargo and engine rooms' hazard, Riser accidents, Dropped objects, Helicopter accidents, structural failures and occupational accidents.

After the analysis, a FAR value of 9.5 was obtained. This value was in line with Statoil's safety requirement of a FAR value less than 10 (Olsvik 2005:13). However, considering the design adopted by Syntroleum, a much lower FAR value is expected when compared to Statoil's design. This is mainly because Syntroleum's technology generates Syngas via an air-blown ATR which doesn't include the ASU.

Safety issues offshore have been dealt with to a considerable extent but more work still needs to be done to properly implement the stringent safety measures adopted by these companies. Verghese (2003:7) pointed out some other areas of safety that needs to be analysed. These are hazards associated with exothermic reactions, the potential for auto-ignition of leaked

hydrocarbons, hot vapour disposal on system blowdown offshore and the necessity for remote flare; amongst other issues already discussed.

Verghese (2003:7) concluded that any offshore deployment of the GTL technology must await resolution of a number of technical feasibility issues. He also suggested that before the technology is deployed offshore, feedback from large projects already queued for execution is an essential pre-requisite. The conclusion drawn by Verghese is a realistic one and must be carefully considered before deployment of these plants offshore.

2.7 GTL ECONOMICS

It is widely accepted that GTL processing economics are highly dependent on plant construction cost, product types and yields, the energy efficiency of the plant, and the market prices of liquids produced.

Al-Saadoon (2005:2) estimated the CAPEX distribution among the three GTL processes as follows:

- Synthesis Gas Generation: 60% of plant CAPEX
- FT Synthesis: 30% of plant CAPEX and,
- Product Upgrade: 10% of plant CAPEX

Although the capital costs predominate, the cost price of natural gas (feedstock) is also an important factor in the overall process economics of FT-GTL plants. Offshore stranded gas fields, remote gas fields or associated natural gas have a low cost or a negative value as an undesirable product.

Apanel (2005:1) declared that in some countries, Wellhead costs of natural gas have been estimated to be below 25 cents per Giga-Joule (GJ). Most

authors peg the cost of natural gas feedstock at 50 cents per MSCF. Some authors however give it a no cost value with the assumption that the gas is associated gas.

Seddon (2004:1) pointed out that existing commercial plants have high production costs and are uncompetitive unless gas price is below 50 US-cents per GJ. He agreed that newer approaches in GTL technology have improved this, but the lowest cost is still likely to require gas below 2 US Dollar per GJ to be competitive with conventional fuels based on crude oil price of 30 US Dollar per barrel. Other published estimates for feedstock (natural gas) cost range between $0/MSCF and $1/MSCF (Maisonnier, 2006; Rahman and Al-Maslamani, 2004). Here 1GJ is assumed to be equal to 1MSCF of gas.

GTL plants are complex and capital intensive, and the offshore GTL plants are even more complex in nature, requiring construction lead time of at least three to five years (Cornot-Gandolphe et al., 2003:12). DeLuca (2005) gave the estimate for Floating GTL plants based on Syntroleum's GTL technology as $20,000/BPD for a 20,000BPD plant and Olsvik (2005) suggested a marinization factor of 1.3 to be used in estimating the CAPEX of floating GTL plants.

Maisonnier (2005:3) estimates a capital expenditure (CAPEX) of 1.5 to 2.1 billion US Dollar for a 60,000 barrel /day onshore plant. This is a CAPEX of 25,000 to 35,000 US Dollar per barrel per day (USD/bpd). These values are obtained when the CAPEX is divided by the plant capacity.

The CAPEX of GTL plants as estimated by various authors to range between 20,000 and 50,000 U.S Dollar per barrel of liquid produced per day (Al-Saadoon, 2005; Maisonnier, 2005; Pirog, 2004; Verghese, 2003; Shen, Venkataraman, and Gray, 2003; and Chang, 2001). This can be compared to capital costs of over 50,000 USD/bpd for earlier plants, such as Shell's Bintulu facility.

Shell asserted that CAPEX for a new GTL facility might decline from 50,000 Dollar per barrel to 20,000 Dollar per barrel as a result of economies of scale consistent with improved technology. Chevron also asserted that the capital cost of a small, 17,000 barrel per day GTL is about 25,000 Dollar per barrel, and experts at BP America assert that the capital cost can approach 20,000 Dollar per barrel of product output (Pirog, 2004).

Abdul-Rahman and Al-Maslamani (2004) estimated the GTL plant operation costs, excluding depreciation and feedstock cost to range from $4 to $6 per barrel. They concluded that the total cost of production of a barrel of GTL product should range between $20 and $30, assuming feedstock cost ranges from 50cents to $1 per MMBTU (equivalent to approx $1/MSCF). See appendix 7.5

Syntroleum's Studies shows that a floating offshore unit with capacity of 20,000BPD can be economical on a stand alone basis, but that it depends on the location and local products prices. The estimated production cost for Syntroleum's offshore GTL units is expected to fall below 13 Dollar per barrel (Maisonnier, 2005). However, this may be difficult to achieve presently due to

recent increase in the price of steel and increasing engineering cost resulting from the upward trend of growth in the GTL industry.

With the current studies it is not really certain if a smaller offshore GTL facility can be economical on a stand alone basis. But, where the utilisation of a GTL facility allows the production of otherwise un-producible oil reserves, the combined economics can be favourable.

The economics for integrated upstream gas fields and offshore GTL plants would be even more attractive than stand alone GTL plants. Including the upstream gas fields often becomes the driver for a successful commercial project. The attraction is primarily because of revenue from Liquefied Petroleum Gas (LPG) and condensates extracted from gas before GTL conversion takes place (Fleisch, Sills, Briscoe and Freide, 2002).

Offshore GTL studies also indicate that the industry is likely to accept leased vessels as an option to outright ownership, for offshore GTL plants, in the same way as the FPSO industry has developed.

2.7.1 Worldwide Investment Activities on GTL Technology

Most investment activities on the GTL technology are taking place in Qatar. Qatar Petroleum is actively pursuing a number of world-scale gas-to-liquids conversion projects for the production of synthetic fuels and base oil stocks (Tyson, 2005:1). The projects are all integrated with offshore development to supply the large amounts of gas needed for these projects. These are active business opportunities that are being pursued, but the status of most of the projects is still at the preliminary stage.

ExxonMobil, Shell, Conoco Phillips, Marathon, SasolChevron and Qatar Petroleum, all announced GTL projects in Qatar. All of the announcements are projected to become operational by 2011 (Pirog, 2004).

Oryx GTL Limited was established at the end of January 2003 as a Joint Venture (JV) company between Qatar Petroleum (51%) and Sasol (49%). The design capacity of the plant is 34,000 BPD of gas-to-liquid fuel. The Engineering, Procurement and Construction (EPC) contract was awarded to Technip. The Estimated cost of the project was nearly $1 billion ($900 million) (Sasol news 2006).

Oryx GTL plant, today's largest commercial GTL plant, with a capacity for 34 000 barrels per day, was officially opened in June 2006 but technical problems delayed production. However, the first shipment of GTL products from the plant hit the market at the end of March, 2007(Sasol news 2007).

Shell's GTL is an integrated project expected to develop about 1.6BSCF/D of North Field gas to produce approximately 140,000BPD of synthetic fuels and base oils. The project will be developed in two phases with the first phase operational in 2009, producing around 70,000BPD of GTL products with the second phase to be completed less than two years later.

Qatar Petroleum and Qatar Shell GTL Limited (Shell) signed the Development and Production sharing Agreement (DPSA) for Pearl GTL in July 2004. They agreed to invest $5 Billion on the 140,000 bpd facility (Pirog, 2004).

Reportedly, ExxonMobil intends to commercialise its proprietary AGC-21(Advanced Gas Conversion for the 21st Century) technology in Qatar.

ExxonMobil's GTL project in Qatar is estimated to cost $7 billion for a plant capacity of approximately 150,000 to 180,000 bpd of GTL products, producing diesel, naphtha and lube base stocks (Waddacor, 2005:7, Pirog, 2004:5).

ConocoPhillips is planning to develop its GTL project in two phases, each producing approximately 80,000 BPD of GTL products - naphtha and diesel using CoPOX technology. Two wellhead platforms with adequate number of wells will provide the required feedstock for the GTL plant (Pirog, 2004:5).

The company completed a feasibility study that was submitted to Qatar Petroleum (QP) in mid 2003. A Statement of Intent to proceed with the project was signed with QP in December 2003. The company proceeded with pre-Front End Engineering Design (FEED) work during 2004. Start-up of the first phase of the plant is scheduled for 2010. The project is structured on the platform of a Production Sharing Agreement, as with all other large-scale GTL projects (Waddacor, 2005:11).

Chevron Nigeria (CNL) and the Nigerian National Petroleum Corporation (NNPC), in an attempt to eliminate gas flaring have also initiated a GTL project in Nigeria, the Escravos Gas-to-Liquids (EGTL) project. The EGTL plant will convert around 300 million cubic feet a day (cf/d) of associated gas into nearly 34,000 barrels of premium quality diesel and Naphtha using Sasol's Slurry Phase Distillate process. The plant is expected to come on-stream in the first quarter of 2008 (Waddacor, 2005:12).

Syntroleum, in a joint venture development agreement with Sovereign Oil and Gas, reached a milestone in a project where they hope to deploy the GTL FPSO. It now has all the permits and requirements to drill its first appraisal

well in the Aje field, located 24km offshore western Nigeria. If appraisal wells support the project, oil production could begin sometime in 2007 with GTL production in 2009 (Marcotte, 2005).

There are also a number of GTL projects under consideration in Australia. SasolChevron has undertaken a feasibility study for a three stage plant in Western Australia. The project could produce about 250,000 bpd of GTL products, involving an investment of A$8 billion and A$1.5 billion ($A = Australian Dollars) in upstream gas supply infrastructure. The plant would produce GTL fuel, naphtha and LPG (Jones, 2003).

See Appendix 7.6 for diagrammatic description of GTL advances all over the world.

2.7.2 Capital Cost Reduction Advances as it affects Offshore GTL

Major technological advancements in the GTL process are geared towards capital cost reduction. The production of synthesis gas has been identified by several authors as the process that attracts the most cost, accounting for about 60% of the total capital cost of a GTL plant.

The US Department of Energy (DOE), in partnership with industry, is supporting the development of Oxygen Ion Transport Membranes, known as either ITM or OTM. The ITM/OTM-Syngas aims to combine the autothermal reformer and the cryogenic ASU in a single reactor. An important feature will be the consequent large reduction in the weight and footprint (area) of the synthesis gas unit, which will make it ideal for offshore applications (Thackeray 2000).

The US DOE partly funded programme is led by Air Products, who say they will hold the resulting patent rights. The other participants are BPAmoco, Chevron, Norsk Hydro, McDermott, Ceramatec, Eltron, Penn State, University of Alaska and the University of Pennsylvania. The participants in the industry funded programme include Amoco, Sasol, Praxair and Statoil (Udovich 1998, Thackeray 2000; Carolan et al. 2001, Shen, Venkataraman & Gray 2003)

This technology when fully developed could be deployed in an offshore GTL plant to reduce capital cost. Thackeray (2000) and Udovich (1998) claim that success in this work will yield enormously important prize of reductions of between 30% and 50% in the Capital costs of FT-GTL plants

Geographical locations of proposed GTL facilities also weigh heavily on CAPEX. Al-Saadoon (2005) introduced the concept of Construction Cost Indices (CCI), originally design for LNG plants in international locations. The CCI relates the capital cost of LNG plants to the proposed geographical location.

However, it is generally believed that GTL plants will follow trends similar to those for LNG plants. Hence, GTL Barges/FPSOs could be built at areas with very low CCI before deployment. This will help reduce the capital cost of Offshore GTL facilities and improve the overall process economics.

2.8 CONCLUSION

From the literatures surveyed, the economic viability of a GTL project depends on four major factors, namely, CAPEX, Operating Cost (OPEX), Feedstock Cost, and Crude oil prices. Significantly low prices for the first three

factors and a high crude oil price will ensure the economic viability of a GTL project. But is this the case for Offshore GTL plants? A close look at the offshore Floating GTL process will show that it should also depend on the factors mentioned above since the technology has been proven feasible technically.

Although much work has been done to prove the feasibility of deploying GTL plants offshore, very little has been done to really show its quantitative cost implications, in terms of the CAPEX, OPEX and expected returns on investment as it relates to plant capacities.

It can also be gathered from this literature survey that most of the planned GTL projects in the world rely on feedstock from offshore gas reserves. However, this review also brings out the following questions: "Why is it necessary to take a GTL process onshore when the resource is mainly offshore?" Is the total cost used to transport the resource to an onshore plant commensurate with the expected returns? Is there a cost saving? Can an offshore GTL plant give any returns on investment? How does the capital cost for an offshore GTL plant compare to pipelining offshore gas to an onshore GTL plant or to the market?

Several authors that researched on the subject claim that offshore deployment of GTL plants could bring about cost savings and high return on investments, but often times, values are not attached to validate these statements. My research work will attempt to fill in these gaps in the Offshore GTL challenge by quantitatively demonstrating the economic viability of a Floating GTL plant using a mathematical model.

CHAPTER THREE

ECONOMIC VIABILITY MODEL

3.1 FINANCIAL ANALYSIS

Today, decision making is increasingly more complex because of uncertainty. Additionally, most capital projects involve numerous variables and possible outcomes. For example, estimating cash flows associated with a project involves working capital requirements, project risk, tax considerations, expected rates of inflation, and disposal/salvage values.

An understanding of existing markets is necessary to forecast project revenues, assess competitive impacts of the project, and determine the life cycle of the project. However, for a production capital project like this, an understanding of the product selling price, feedstock costs, operating costs, additional overheads and capacity utilization is necessary. Consequently, a capital project cannot be managed by simply looking at the numbers; i.e. discounted cash flows. A critical analysis of the entire decision and assessment of all relevant variables and outcomes within an analytical hierarchy has to be done.

This analysis will primarily focus on a Floating GTL plant placed on an FPSO or a Barge. Five main investment appraisal economic tools will be combined with the economy of scale concept in a model to critically analyse and demonstrate the economic viability of a floating GTL plant. The appraisal economic tools employed are the Net Present value (NPV), Internal Rate of Return (IRR), Discounted Payback Period (DPBP), Profitability Index (PI) and the Break-Even Analysis (BEA).

However, my main focus is on the NPV, while the other approaches are used as complementary tools. This is because the NPV has been identified as the tool that provides the most reliable result (Ross, Westerfield & Jordan 2003, Van Horne & Wachowicz 1992, Mott 1992).

3.1.1 NET PRESENT VALUE (NPV)

In simple terms the NPV is the difference between an investment's market value and its cost. Van Horne and Wachowicz (1992) defined it as the present value of an investment proposal's net cash flows less the proposal's initial capital outflow (also known as the Capital Expenditure – CAPEX). The NPV is dependent on the following:

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

The NPV is expressed as:

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

$$= -ICO_0 + \frac{CF_1}{(1+k)} + \frac{CF_2}{(1+k)^2} + \ldots + \frac{CF_{N-1}}{(1+k)^{N-1}} + \frac{CF_N}{(1+k)^N} + SV \qquad 3.2$$

Where,

ICO = Initial Cash outflow, which is the CAPEX

CF_N= Operating Cash Flow for the nth year

N= Project Life, in years

SV= Salvage Value, and

k= discount factor or rate

3.1.2 INTERNAL RATE OF RETURN (IRR)

The internal rate of return (IRR) for an investment proposal is the discount rate that equates the present value of the expected net operating cash flows (CFs) with the initial cash outflow (ICO) which is the CAPEX in this case. The IRR can be derived using the following formula:

$$ICO_0 = \frac{CF_1}{(1+IRR)} + \frac{CF_2}{(1+IRR)^2} + \ldots + \frac{CF_{N-1}}{(1+IRR)^{N-1}} + \frac{CF_N}{(1+IRR)^N} \qquad 3.3$$

Where,

ICO = CAPEX

CF= Operating Cash Flow and

N= Project's useful Life Cycle

3.1.3 PROFITABILITY INDEX (PI)

The profitability index (PI), or benefit cost ratio, of a project is the ratio of the present value of the future cash flows to the CAPEX. It can be expressed as:

$$\text{PI} = \left[\frac{CF_1}{(1+k)} + \frac{CF_2}{(1+k)^2} + \ldots + \frac{CF_{N-1}}{(1+k)^{N-1}} + \frac{CF_N}{(1+k)^N} + CAPEX \right] \Big/ CAPEX \qquad 3.4$$

3.1.4 DISCOUNTED PAYBACK TIME (DPBP)

The Discounted Payback Period is the length of time until the sum of the discounted Cash Flow is equal to the initial investment on the project. In simple terms, this is the number of years required to recover the initial capital investment (CAPEX).

3.1.5 BREAK-EVEN ANALYSIS

One of the most common tools used in evaluating the economic feasibility/viability of a new project or product is break-even analysis. According to Ross, Westerfield and Jordan (2003:356), the break-even point is the point at which revenue is exactly equal to costs. At this point, no profit is made and no losses are incurred.

The break-even point can be expressed in terms of unit sales or dollar sales. That is, the break-even units indicate the level of sales that are required to cover costs. Sales above that number result in profit and sales below that number result in a loss. The break-even sales indicate the dollars of gross sales required to break-even (Ross, Westerfield & Jordan, 2003).

It is important to realize that a company will not necessarily produce a product just because it is expected to breakeven. Many times, a certain level of profitability or return on investment is desired. If this objective cannot be reached, which may mean selling a substantial number of units above break-even, the product may not be produced. However, break-even is an excellent tool to help quantify the level of production needed for a new project or a new product (Holland, 2000).

Break-even analysis is based on two types of costs: fixed costs and variable costs. Fixed costs are overhead-type expenses that are constant and do not change as the level of output changes. Variable expenses are not constant and do change with the level of output (Ross, Westerfield & Jordan, 2003:356).

"One important aspect of break-even analysis is that it is normally not this simple. In many instances, the selling price, fixed costs or variable costs will not remain constant resulting in a change in the break-even. So, a break-even cannot be calculated only once. It should be calculated on a regular basis to reflect changes in costs and prices and in order to maintain profitability or make adjustments in the product line". (Holland, 2000:1.)

According to Ross, Westerfield and Jordan (2003), the general break-even expression is given by:

$$Q = \frac{FC^* + OCF}{P - v} \qquad 3.5$$

Where,

Q = Quantity of output or sales volume at break-even point

OCF = Operating Cash Flow

FC* = Total Fixed Cost (CAPEX)

P = Price per unit, and

v = Variable cost per unit

Ross, Westerfield and Jordan (2003:366) stated that the general equation for determining the break-even point can be used to determine the accounting, cash and financial break-even points. The accounting and cash break-even analyses have been considered for this study.

The accounting break-even occurs when net income is zero. Operating cash flow is equal to depreciation when net income is zero, so the accounting break-even point is:

$$Q = \frac{FC^* + D}{P - v} \qquad 3.6$$

"A project that always just breaks even on an accounting basis has a payback exactly equal to its life, a negative NPV and an IRR of zero". (Ross, Westerfield & Jordan, 2003.)

The cash break-even occurs when the operating cash flow is zero. The cash break even point is thus:

$$Q = \frac{FC^*}{P - v} \qquad 3.7$$

"A project that always just breaks even on a cash basis never pays back, has an NPV that is negative and equal to the initial outlay, and has an IRR of -100 percent". (Ross, Westerfield & Jordan, 2003.)

3.1.6 PROJECT ECONOMIC VIABILITY CRITERIA

The following rules will apply to the results obtained from my analysis using the economic tools described above:

- If the net present value (NPV) is **greater than zero**, the project is economically viable
- If the net present value (NPV) is **less than zero**, the project is rejected and is therefore not a viable project
- If the profitability index of the project is **greater than 1.00**, the investment proposal is acceptable and it is economically viable
- If the profitability index of the project is less than 1.00, the investment proposal is not acceptable and the project is therefore not economically viable
- Based on the IRR rule the project should be acceptable if the IRR exceeds the required return. It should be rejected otherwise.

- Finally, the Break-Even Analysis (BEA) will be used to determine the size of gas field and sales volume that would make the project profitable.

For any project the NPV and the PI methods give the same accept-reject signals. However, the net present value is preferred over the profitability index method. The reason for this is that the NPV expresses the absolute monetary economic value that the project makes, whereas the profitability index expresses only the relative profitability of the project.

Hence, for this analysis, the PI and DPBP will only be used as complementary economic tools. The final decision to suggest the viability of a project scenario will be dependent on the net present value (NPV) and the IRR. For this reason, comments will be made about the results obtained from the other two economic appraisal approaches/tools only as warranted.

3.1.7 ECONOMY OF SCALE

Economy of scale is another tool that will be adopted to develop the Economic Viability (EV) Model for this study. According to Lipsey (2000:2), economy of scale refers to the notion of increasing efficiencies of the production of goods as the number of goods being produced increases. In the context of this study however, economy of scale is simply used to describe the effect of scale on construction cost (CAPEX). In other words, this is the reduction in Capital Cost resulting from increased production capacity.

In the Chemical/Processing Industry, mathematical expressions exist that clearly show the cost implications of economies of scale (Hendrickson and Au

2003). A non-linear cost relationship often used in estimating the cost of a new processing plant from the known cost of an existing plant of a different size/capacity is known as the ***exponential rule*** or ***the rule of six-tenths power of capacity*** (Kerzner 2001, Hendrickson and Au 2003).

Let C_a be the cost of an existing facility with capacity Q_a, and C_b be the estimated cost of the new facility which has a capacity Q_b. Then,

$$C_b = C_a\left(\frac{Q_b}{Q_a}\right)^m \qquad 3.8$$

where m usually varies from 0.5 to 0.9, depending on the facility. However, a value of **m = 0.6** is often used for chemical processing plants and refineries (Kerzner 2001, Hendrickson and Au 2003). Equation 3.9 can be reduced to a linear relationship thus:

$$\ln C_b = \ln C_a + m\ln\left\{\frac{Q_b}{Q_a}\right\} \qquad 3.9$$

Or $$\ln\left(C_b/C_a\right) = m\ln\left(Q_b/Q_a\right) \qquad 3.10$$

This rule can be used to estimate the total cost of a complete facility with reference to a base case.

3.1.7.1 RATIONALE FOR SCALE ECONOMIES

Floating GTL plants are movable and can therefore be used for series of projects. This implies that the plant is not limited to any particular region. Therefore, instead of deploying a small capacity plant that can only explore from a single reserve, a greater capacity plant can be built to explore from two or more of such reserves over its useful life due to its mobile nature.

Let us assume the case of a highly fragmented gas field, where reserves are scattered in small quantities over the entire region. Instead of deploying smaller capacity floating plants, a large capacity plant can be deployed to explore the reserves in the region over a shorter period. The overall economics might be attractive if the scale economies are incorporated.

3.2 GENERAL ASSUMPTIONS AND NOTES

3.2.1 PLANT CAPACITY

The following plant capacities shown in table 3.1 will be considered for this analysis:

Plant Capacity (BPD)	*Gas Volume (MSCF/D)*	*Design Status*
10,000	100	Assumed: For purpose of study
14,500	***145***	***Available: Statoil's design***
20,000	***200***	***Available: Syntroleum's design***
30,000	300	Assumed: for purpose of study
40,000	400	Assumed: for purpose of study
50,000	500	Assumed: for purpose of study
70,000	700	Assumed: for purpose of study
100,000	1000	Assumed: for purpose of study

Table 3.1: Plant capacities for Floating GTL plant

The capacities shown in table 3.1 are related to design capacities already proposed by the major players in the offshore Floating GTL challenge and some assumed futuristic capacities proposed for the purpose of this study.

The plant capacities highlighted are the base case capacities that will be used for this study, representing existing designs for Statoil and Syntroleum.

3.2.2 PLANT CAPEX

Construction periods for floating GTL plants range from 3 to 5 years (Guegel 2005, Worley International 2000). However, for the purpose of this study a 3 years construction/pre-commissioning period is assumed.

Solomon (2006:84) stated that "cost and personnel activities are both low at the beginning of a project, are high near the middle of the project and tend to tapper off to a low level as the project nears completion". Based on Solomon's postulation, the following CAPEX distribution for the Construction period of the Floating GTL plant is assumed which is close to a real situation: see table 3.2.

Year	Percentage of CAPEX
1	10%
2	60%
3	30%

Table 3.2: CAPEX distribution

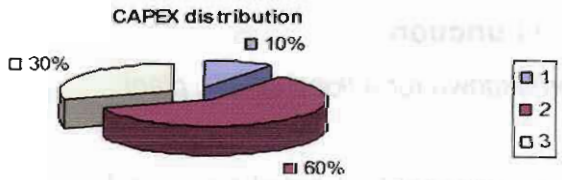

Fig 3.1: Chart showing CAPEX distribution

Singleton and Cooper (1997:18) gave a conceptual CAPEX breakdown for a typical floating GTL plant. However, due to inflation and other factors that can influence the CAPEX of a process plant, the percentage distribution might not be accurate but it will give a general idea of the cost functions associated with a Barge/FPSO mounted GTL plant. The breakdown is shown in table 3.3

CONCEPTUAL CAPEX BREAKDOWN	
Cost Function	**CAPEX Percentage**
Vessel Acquisition and Amortisation	2.97%
Life Extension Measures	1.49%
Engineering Systems and Structures for GTL Plant	4.57%
Upgraded Ship Systems	2.00%
Mooring and Internal Turret	12.38%
Crude/gas process and Flare	3.09%
Naval Architecture, Marine Engineering and Supervision	0.55%
GTL Plant	72.95%
Total	**100.00%**

Table 3.3: Conceptual CAPEX breakdown for Floating GTL plant

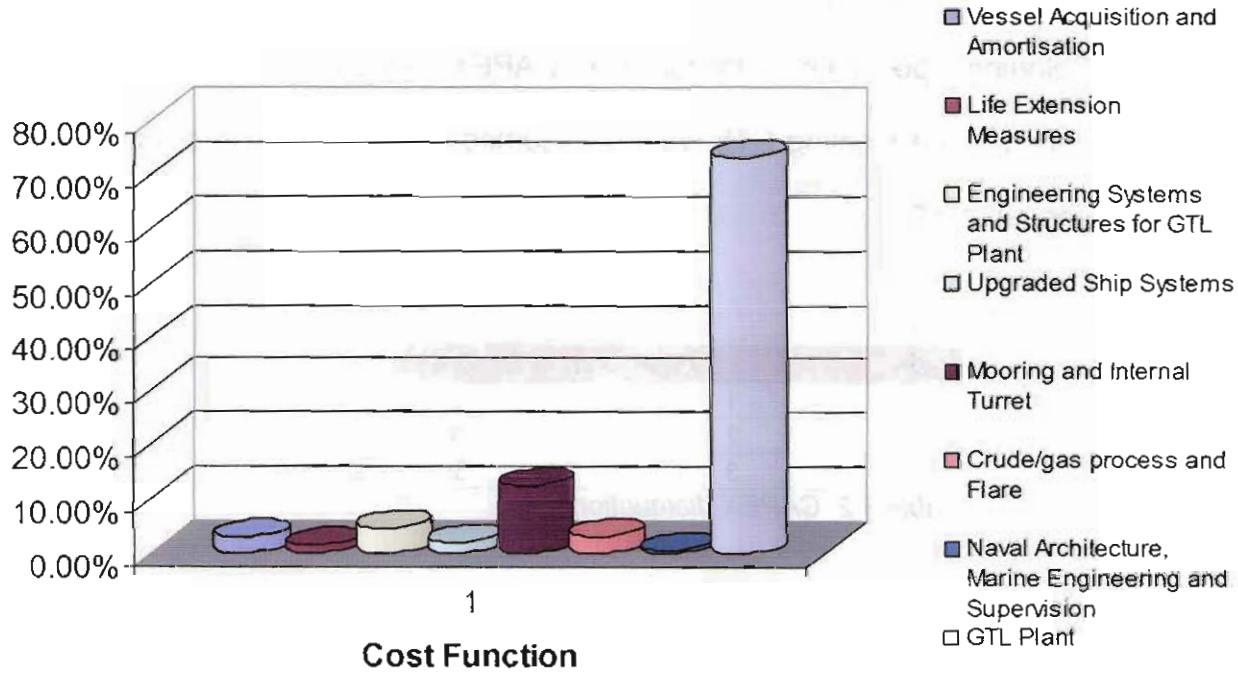

Figure 3.2: Conceptual CAPEX breakdown for a floating GTL plant

The cost of marinization from the conceptual breakdown in figure 3.2 above makes up almost 30 percent of the plant CAPEX.

DeLuca (2005) gave the estimate for Floating GTL plants based on Syntroleum's GTL technology as $400million for a 20,000BPD which is equivalent to a CAPEX of $20,000/BPD. This CAPEX value of $20,000/BPD will form the first base case for this analysis based on Syntroleum's design representing the Capital Expenditure for a 20,000BPD plant.

Although, recent steel price increase since 2005 and expansion in the process industry (which has caused increase in engineering cost) could fault the CAPEX estimate given by DeLuca, sensitivity analysis will be carried out in the course of this study to cover up for the lapses that might occur. See appendix 7.7A for Steel price trends in year 2006 and early 2007.

Recall that Al-Saadoon (2005) estimated the CAPEX breakdown among the three GTL processes as follows:

- Synthesis Gas Generation: 60% of plant CAPEX
- FT Synthesis: 30% of plant CAPEX and,
- Product Upgrade: 10% of plant CAPEX

Olsvik (2005) in his report confirmed that, as at 2000 Statoil's estimated target for the CAPEX of an onshore equivalent of their offshore GTL plant is between $25,000/BPD and $30, 000/BPD. He went ahead to provide a marinization factor of 1.3. With this factor, it is possible to obtain CAPEX of an offshore GTL plant if that of an onshore plant of equal capacity is known. This implies that the offshore CAPEX is the onshore CAPEX multiplied by the marinization factor.

Sasol's Slurry Phase Distillate (SSPD) technology has been adopted for Statoil's Offshore GTL plant design (Olsvik 2005). The onshore design includes the Air Separation Unit (ASU) and the Autothermal Reforming (ATR) unit, making up the Syngas generation section, the Fischer-Tropsch (FT) section (SSPD) and the Product Upgrade section. Meanwhile, for Statoil's offshore design the Product Upgrade section is not included, which means that the final deliverable for their offshore design is ***Syncrude***.

Recent studies shows that Sasol's onshore GTL plant in Qatar commissioned in 2006 cost about $900 million for a 34,000 BPD capacity, which is a CAPEX of about $27,000/BPD (Maisonnier, 2006:3; Waddacor, 2005:11). In this study however, for the second base case, we shall adopt Sasol's figures for CAPEX for Statoil's GTL plants because:

- Sasol's figures are based on actual plant costs and are not mere estimates
- Statoil design is based on Sasol's technology
- The figures from Sasol's Qatar plant are more recent and may have factored in the recent industry developments

Based on this premise, a CAPEX for Statoil's offshore design will be estimated using the ***CAPEX breakdown estimate*** given by Al-Saadoon (2005), the ***economy of scale*** concept and the ***marinization factor*** proposed by Olsvik (2005).

Given that Sasol's 34,000 BPD onshore plant cost $27,000/BPD. Therefore the CAPEX without the Product Upgrade Section will be 90% of the original CAPEX (i.e. less the cost of the Upgrade section given as 10%), which is:

$27,000 X 0.9 = $24,300/BPD

= $24,300 X 34,000

= $826million (Approx.)

This cost represents the CAPEX for a 34,000BPD onshore GTL that doesn't include the Upgrade section, but Statoil's offshore design is for a 14,500BPD

plant. Therefore, the CAPEX for an onshore equivalent of the plant is calculated thus using the economy of scale concept:

$$C_{14500} = \$826\left(\frac{14500}{34000}\right)^{0.6}$$

= $495 million (Approx.)

Multiplying this value with the marinization factor given by Statoil, the CAPEX for the 14,500BPD offshore GTL plant will be:

= $495 X 1.3

= *$644 million*

The CAPEX per barrel of product becomes $\frac{\$644 \times 10^6}{14500BPD}$ which is approximately ***$44,000/BPD;*** compared to $20,000/BPD for a 20,000BPD plant based on Syntroleum's design.

This seeming conflict in the CAPEX for Statoil and Syntroleum's design is explainable as follows:

- After the release of Syntroleum's figures in 2005, there has been a significant increase in the price of steel, see Appendix 7.7 and 7.7A
- Unlike Statoil's design, Syntroleum's design doesn't include the ASU which takes up about 60% of the Syngas generation cost
- The technology for the two designs is not the same.

3.2.3 OPERATING EXPENDITURE

The Operating Expenditure (OPEX) is given by the following formula:

$$OPEX = OC + FC + SC \qquad 3.12$$

Where:

OC = Operating Cost

FC = Feedstock Cost and

SC = Shipping Cost

3.2.3.1 Operating Cost (OC)

Operating Cost is the sum of the Maintenance Cost (MC) and the Running Cost (RC) of the plant, in dollar per barrel of product. This is denoted as:

$$OC = MC + RC \qquad 3.13$$

Rahman and Al-Maslamani (2004) and Maisonnier (2006) estimated a typical plant OC excluding depreciation and feedstock cost to range between $4 and $6 per barrel for land based GTL plants.

However, an OC of $5 per barrel of product will be adopted for this analysis. To apply this OC value to an offshore scenario, the OC value of $5 will be multiplied by a marinization factor of 1.3 proposed by Olsvik (2005) for the Statoil's offshore GTL survey.

An OC of $5/Barrel onshore will be ≡ $(5 X 1.3)/Barrel offshore

≡ **$6.5/Barrel**

OC for this study will be $6.5 per barrel of product. It is expected that offshore operations will attract additional cost when compared to land based operations. This is due to safety issues, maintenance issues and other risk based factors related to the operating conditions offshore.

3.2.3.2 Feedstock (Natural Gas) Cost

There is the possibility that the major offshore gas reservoirs are retrograde reservoirs, requiring gas processing and gas cycling for a number of years,

prior to blow-down. Otherwise, potentially valuable natural gas liquids and condensate would not be recovered, and gas deliverability could be impacted, depending on how pronounced the liquid formation is around the well bores.

However, this is a reservoir management issue that is beyond the scope of this study, but could dictate the manner in which the offshore gas is produced and therefore impact the costs incurred to process and re-cycle the gas.

For this analysis, gas processing is considered to be included in the feedstock cost (FC). Published estimates for feedstock (natural gas) cost range between $0/MSCF and $1/MSCF (Maisonnier 2006, Rahman and Al-Maslamani 2004).

Arianto and Siallagan (2000:2) stated that the conversion rates for Sasol's and Syntroleum's GTL technologies are the same. This ratio was given as: 10,000scf gas produces 1 Barrel of GTL product. For this study the assumed Feedstock Cost is stated below:

Assumed Gas Price: $1/MSCF ≡ $1/1000 SCF

But, 10,000 SCF ≡ 1 Barrel of Product

Therefore, Feedstock Cost (FC) per barrel of products will be:

$$\left(\frac{1}{1000SCF}\right)\times\left(\frac{10{,}000SCF}{1Barrel}\right)=\$10/Barrel$$

= $10 per Barrel of Product

3.2.3.3 SHIPPING COST (SC)

For this study, the Shipping Cost is assumed to be Free-On-Board (FOB). Free on Board or FOB, is used in commerce to describe the value of goods at point of embarkation, excluding transportation and insurance costs.

In an FOB shipping contract, the buyer of the products pays the cost of shipping and assumes any risk of loss or damage. Export values are usually expressed FOB for customs and excise purposes, while imports are usually valued CIF (cost, insurance, and freight); the seller pays for shipping and assumes any risk (Microsoft Encarta Reference Library 2005).

Hence, cost of shipping for this study will be paid by the buyer of the product and will not be included in the OPEX for this analysis.

3.2.4 PRODUCT PRICE

Depending on local and nearby market circumstances, the most desirable gas-to-liquids (GTL) product would be one of the following:

- Syncrude.
- Gasoline.
- Diesel and
- Naphtha.

The product price assumed for this study is $55 per barrel of product based on an assumed expected premium of $5 per barrel for GTL products and a minimum crude oil price of $50 per barrel. This amount is assumed based on the upward trend of crude oil and petroleum products prices over the past two (2) years. See appendix 7.2

3.2.5 LIFE EXPECTANCY

Floating GTL plants are, by their nature, very portable. Little, if any, modifications to the process system would be required to relocate the system to another field (Worley International, 2000:21). The expected useful life of

such a system is at *least* twenty years. However, the plant useful life assumed for this analysis is 25years.

3.2.6 SALVAGE VALUE

The Salvage Value (SV) is the value of the plant at the end of its useful life. The Salvage value in this case is equal to the cost of the ship or floating platform after dissembling the plant.

For this study, the cost of dissembling the plant is assumed to be equal to the value of the ship or platform after its useful life. Hence, the Salvage value is: (Cost of plant after dissembling) minus (Cost of dissembling the plant) which will be equal to zero in this case.

$$SV = zero$$

3.2.7 DEPRECIATION

Depreciation, in accounting and economics, is a process of allocating in a systematic and rational manner the cost of a capital asset over the period of its useful life (Mott, 1992:24). Depreciation takes into account the decrease in the service potential of capital assets invested in a business venture, resulting from such causes as physical wear and tear in ordinary use.

The cumulative depreciation since acquisition is reported as a deduction from the cost of the related asset. The difference is referred to as the asset's "carrying amount" or "book value." The periodic depreciation charge enters into the computation of net income.

Several methods are used in calculating periodic depreciation. The most widely used is the straight-line method, in which the rate of depreciation is

constant for the entire working life of the capital assets. Thus, if a plant cost $11000 and is assumed to have a 10-year useful life and a scrap value of $1000 at the end of 10 years, the amount of annual depreciation would be calculated thus:

Total depreciation = $(11000 – 1000) = $ 10,000

Annual depreciation = $10,000 / 1000 = $1000

And, the annual depreciation rate,

$$ADR = \frac{1000}{10000} \times 100\%$$

$$= 10\%$$

When the use of a capital asset is not constant over a period of time, a second method called the service-unit method or unit of production method is utilized. Here the scrap value is deducted from the cost of the asset and the remainder divided by the number of units the asset is expected to yield. The result is depreciation expressed in units produced or units of service performed.

However, for this study straight line depreciation is assumed for the entire useful life of the plant since the plant use is constant over the period. Based on the 25years useful life of the plant and a zero salvage value, the depreciation will be:

100%/25years = 4% Plant CAPEX per annum

3.2.8 CORPORATE TAX

A global survey of corporate tax rates around the world for 2006 averages at 29 percent (KPMG, 2006). Hence, a fixed tax rate of 29% will be used for this study.

3.2.9 DISCOUNT RATE

A 15% discount rate will be adopted for the base case economic assumption of this study as suggested by Ross, Westerfield and Jordan (2003) for new projects. However, NPV and PI will also be estimated using 10%, 20% and 25% discount rates.

3.3 MODEL DESIGN

The model used in this study (EV model) is meant to provide a quantitative tool to evaluate the economic viability of a Floating GTL plant designed to operate offshore. Qualitative studies on the floating GTL concept have been covered by several authors, but very little has been done to quantitatively evaluate its economic viability.

The model has been designed on an excel spreadsheet. It has been designed to exhibit a very high level of flexibility. Its flexibility is such that a single plug in of variables based on any case scenario will generate a new set of results. This could be achieved with a range of production capacities, feedstock prices, operating expenditures, taxes, capital costs and product prices.

The EV model shall provide a framework to evaluate published or related to actual project expenses and cost estimates for floating GTL plants.

3.3.1 INTEGRATION OF PARAMETERS AND ECONOMIC TOOLS

Recall from equation 3.2 that

$$NPV = -ICO_0 + \frac{CF_1}{(1+k)} + \frac{CF_2}{(1+k)^2} + \ldots + \frac{CF_{N-1}}{(1+k)^{N-1}} + \frac{CF_N}{(1+k)^N} + SV$$

Given that the CAPEX was spread over three (3) years, the NPV becomes:

$$= -CO_0 - \frac{CO_1}{(1+k)} - \frac{CO_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \ldots + \frac{CF_{N-1}}{(1+k)^{N-1}} + \frac{CF_N}{(1+k)^N} + SV \qquad 3.13$$

Where CO = Cash Outflow

Given a 10%, 60% and 30% CAPEX distribution and SV equal to zero, then:

$$NPV = -0.1CO_0 - \frac{0.6CO_1}{(1+k)} - \frac{0.3CO_2}{(1+k)^2} + \ldots + \frac{CF_{N-1}}{(1+k)^{N-1}} + \frac{CF_N}{(1+k)^N} \qquad 3.14$$

From equations 3.11 and 3.12 we recall that:

OPEX = OC + FC + SC, and

OC = MC + RC

Therefore, OPEX = MC + RC + FC + SC 3.15

But, the Gross Income (GI) per day is given as the Plant Capacity (PC) in Barrel per day multiplied by the Product Price (PP) in dollar per barrel. Assuming that the plant runs for **340 days** annually, to allow for Maintenance and other unplanned situations like trips, the GI per annum will be:

GI = PC X PP X 340 3.16

The Net Working Capital (NWC) is given as the difference between the Gross Income and the Operating Expenditure (OPEX). Therefore,

NWC = GI – OPEX 3.17

The Earnings Before Interest or Tax (EBIT) per annum is given as the difference between the Net Working Capital (NWC) and the Depreciation (D). This is denoted as:

EBIT = NWC – D 3.18

Where

$$D = 0.04*CAPEX \quad 3.19$$

The corporate tax (T) is calculated based on the EBIT. Hence, the Tax will be given as the product of the Tax rate (TR) and the Earning Before Interest and Tax (EBIT). That is,

$$T = TR \times EBIT \quad 3.20$$

Given that TR is 29%, therefore:

$$T = 0.29\ EBIT \quad 3.21$$

The Operating Cash Flow (CF) per annum is the sum of the Earning Before Interest and Tax (EBIT) and the Depreciation (D) less the Tax (T) paid, i.e.:

$$CF = EBIT + D - T \quad 3.22$$

The cash flow obtained in equation 3.23 above is used to calculate the NPV using different discount rates (10%, 15%, 20% and 25%). Recall that, 15% discount rate is used for the base case scenario.

To determine the Discounted PayBack Period (DPBP), the annual Cash Flows are discounted using different discount rates to obtain the Discounted Cash Flow (DCF), then the Cumulative Discounted Cash Flow (CDCF) is used to the determine the project's DPBP where the CDCF is equal to the initial investment (CAPEX). For year n, the discounted cash flow is:

$$DCF_n = CF_n \times \text{Discount Factor (DF)} \quad 3.23$$

And the cumulative discounted cash flow:

$$CDCF = \sum_{N=28}^{N=1} DCF \qquad 3.25$$

3.4 BASE CASE ANALYSIS

The analysis for this study will be done on a case by case basis. Here, two base cases scenarios are considered. Each base case scenario represents a particular plant capacity and its corresponding CAPEX, which will in turn be used to generate CAPEX values for other assumed capacities using the economy of scale concept. The new CAPEX values will be determined using the economy of scale relationship in equation 3.8:

$$C_b = C_a \left(\frac{Q_b}{Q_a} \right)^m$$

The Base case scenarios are the 14,500 BPD plant with a CAPEX of $44,000/BPD and the 20,000 BPD plant with a CAPEX of $20,000/BPD, indicating existing design capacities for Statoil and Syntroleum respectively.

3.4.1 BASE CASE SCENARIO_ONE

This base case scenario presents a 20,000BPD plant with a $20,000/BPD CAPEX based on Syntroleum's design. This is used to generate corresponding CAPEX values for other assumed capacities ranging from 10,000BPD to 100,000BPD in table 3.4. The Plant Capacities and their corresponding CAPEX values will then be used on the EV model to generate results that will be analysed in the following chapter.

Plant Capacity (MBPD)	Plant CAPEX (MM$)	Plant CAPEX (M$/BPD)
10.0	260	26.0
20.0	400	20.0
30.0	510	17.0
40.0	600	15.0
50.0	700	14.0
70.0	840	12.0
100.0	1,100	11.0

Table 3.4: CAPEX values used for each scenario based on Syntroleum's design

However, the following Cost codes are kept constant for each scenario:

OC = $6.5/Barrel

FC = $10/Barrel

DR = 15%

TR = 29%

D = 0.04 CAPEX per annum

PP = $55/Barrel

3.4.2 BASE CASE SCENARIO_TWO

This base case scenario presents a 14,500BPD plant with a $44,000/BPD CAPEX based on Statoil's design. This is used to generate corresponding CAPEX values for other assumed capacities ranging from 10,000BPD to 100,000BPD in table 3.5. The Plant Capacities and their corresponding CAPEX values will then be used on the EV model to generate NPV, IRR, PI and DPBP results that will be analysed in the following chapter.

Plant Capacity (MBPD)	Plant CAPEX (MM$)	Plant CAPEX (M$/BPD)
10.0	510	51.0
14.5	638	44.0
30.0	990	33.0
40.0	1,160	29.0
50.0	1,350	27.0
70.0	1,610	23.0
100	2,000	20.0

Table 3.5: Showing CAPEX values used for each scenario based on Statoil's design

However, the following Cost codes are kept constant for each scenario:

OC = $6.5/Barrel

FC = $10/Barrel

DR = 15%

TR = 29%

D = 0.04 CAPEX per annum

PP = $55/Barrel

3.4.3 BREAK-EVEN ANALYSIS

Recall from equation 3.5 that:

$$Q = \frac{FC^* + OCF}{P - v}$$

The quantity of output at the break-even point, Q is estimated using the EV model for the base case scenarios 1 and 2 (i.e. using the information in tables 3.4 and 3.5 above).

Where:

FC* = CAPEX ($)

P = PP ($/Barrel), and

v = OPEX = (OC + FC) ($/Barrel)

Also recall that OCF equals D for accounting break-even point and zero for the cash break even point.

3.5 SENSITIVITY ANALYSIS

Sensitivity analysis has been carried out to test the sensitivity of the NPVs and IRRs obtained to changes in the base case scenario CAPEX values, Product Price (PP), Feedstock Cost (FC) and Operating Cost (OC). The

differences obtained from the variance of this cost codes will be used to generate plots which will be analysed accordingly. See table 3.6 below:

SENSITIVITY PARAMETER	*1*	*2*	*3*	*4*	*5*	*6*
FEEDSTOCK COST (FC) ($/Bbl)	0	5	10	20	30	40
OPERATING COST (OC) ($/Bbl)	5	10	15	20	30	40
PRODUCT PRICE (PP) ($/Bbl)	20	30	40	50	60	70
BASE CASE CAPEX (M$/BPD)	30	50	60	-	-	-

Table 3.6: Showing varying cost codes for Sensitivity Analysis

However, four (4) cases will be considered for the sensitivity analysis. The base cases of 20,000BPD and 14,500BPD plants with their corresponding CAPEXs will represent the first two cases (representing Syntroleum and Statoil's design). Also, a 70,000BPD plant capacity will be considered under both cases (using the economy of scale concept for the CAPEXs) to represent the third and fourth case.

The sensitivity analysis shall amongst other things be used to account for adjustments across different geographical areas. More so, there is no guarantee that the plant operates at the most efficient combination for its entire useful life. These and many other factors could affect the Operating Expenditure including wages, salaries and Maintenance Costs, and the final Product Price; and therefore affect an investment decision.

CHAPTER FOUR

RESULTS AND DISCUSSIONS

4.1 PRESENTATION OF RESULTS

This section presents the NPV, IRR, DPBP and PI results generated using the EV Model developed in the previous chapter. This is done for varying Plant Capacities (PC) with their corresponding Plant CAPEXs, each representing a case scenario. It also presents the results of the sensitivity analysis carried out on the various cost parameters using the EV model.

We should recall the project viability/acceptance criteria discussed in the previous chapter for the various economic appraisal tools employed in this analysis. This can be summarised thus:

- If the net present value (NPV) is **greater than zero**, the project acceptable and it is economically viable; it is unacceptable otherwise
- If the profitability index of the project is **greater than 1.00**, the investment proposal is acceptable and it is economically viable; it is unacceptable otherwise
- Based on the IRR rule the project should be acceptable if the IRR exceeds the required return. It should be rejected otherwise.

4.2 INTERPRETATION OF RESULTS

NPV1, NPV2, NPV3 and NPV4 as used in this analysis represent Net Present Values for 10%, 15%, 20% and 25% discount rates respectively. Also PI1, PI2, PI3 and PI4 are Profitability Index values for 10%, 15%, 20% and 25% discount rates respectively. DPBP is the discounted payback period for a particular case scenario calculated at 15% discount rate. See appendix 7.4

4.2.1 BASE CASE SCENARIO ONE

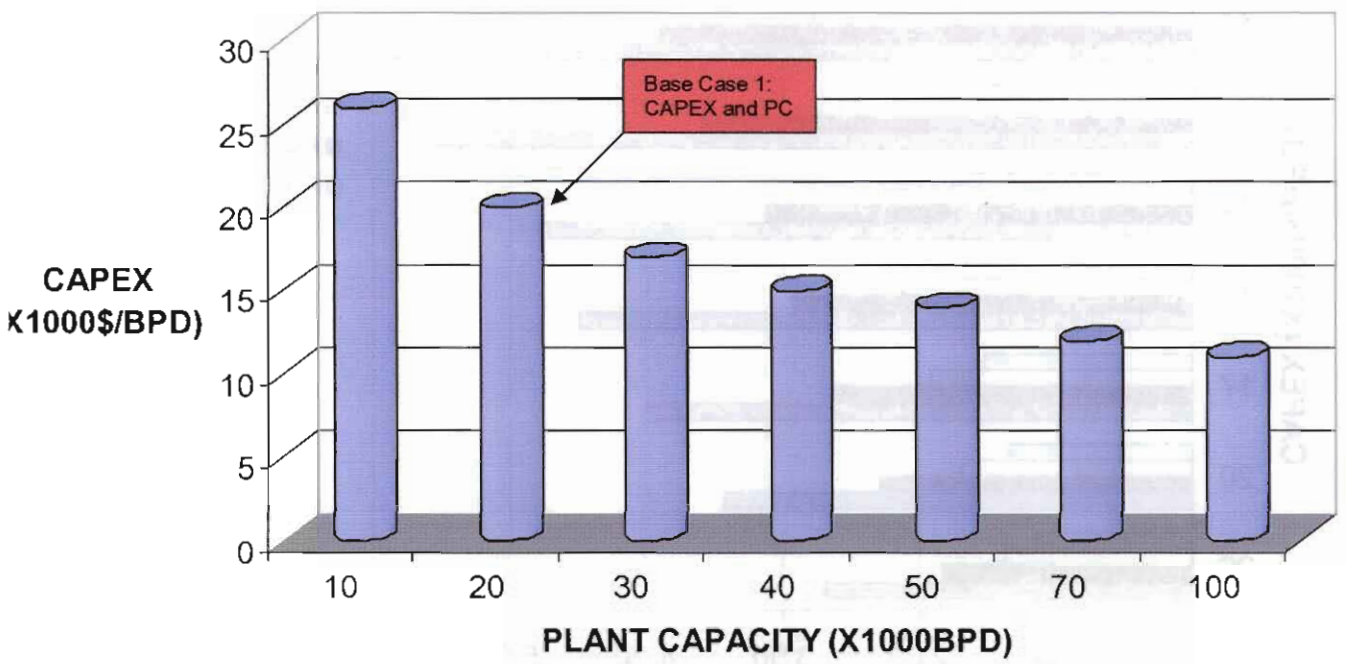

Fig 4.1: Chart showing Economy of Scale relationship for base case scenario one

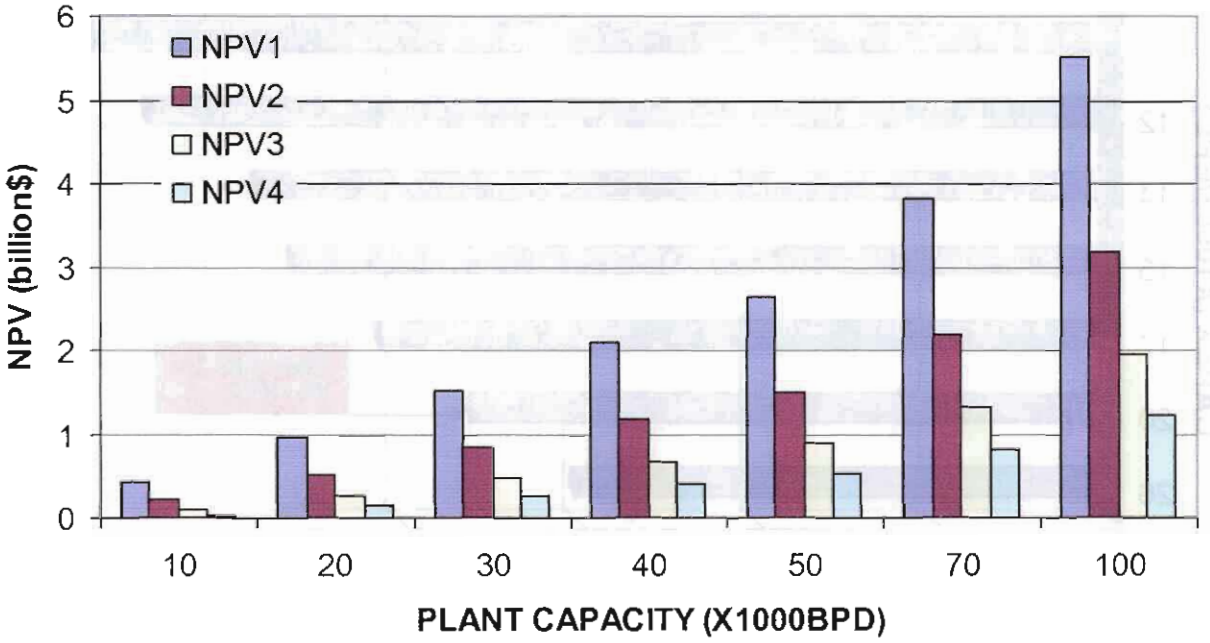

Fig 4.2: Chart showing NPVs for varying Plant Capacities base case scenario one

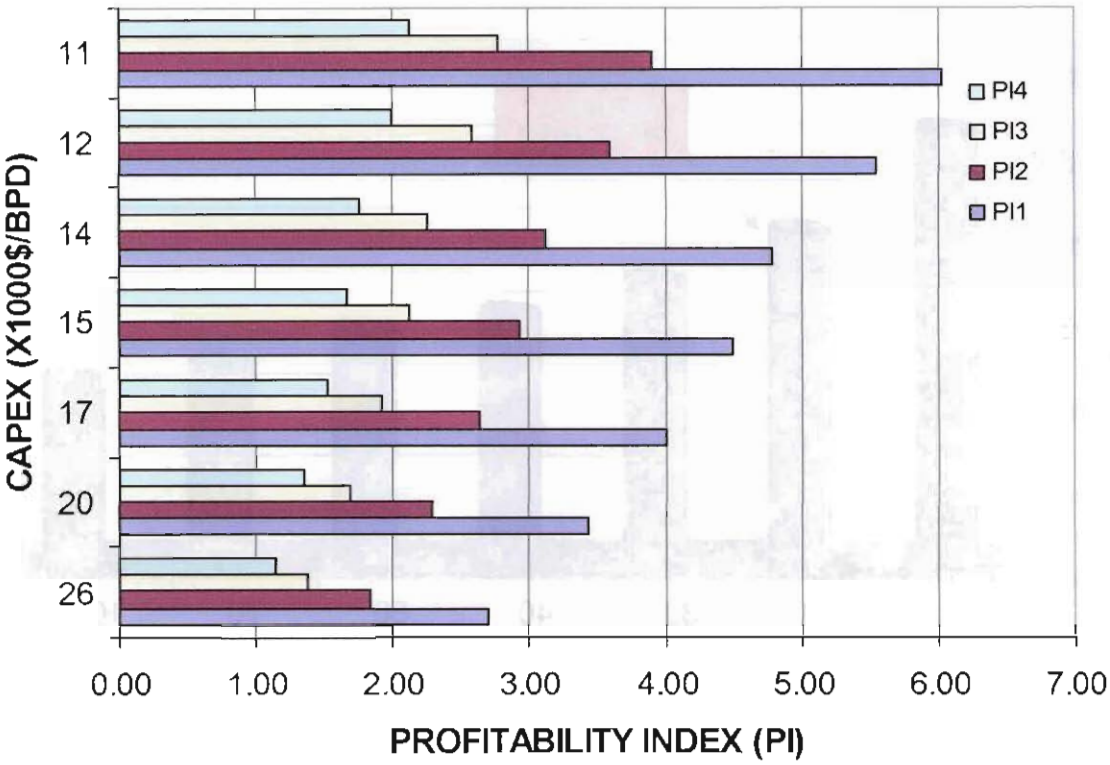

Fig 4.3: Chart showing PIs for varying CAPEXs for base case scenario one

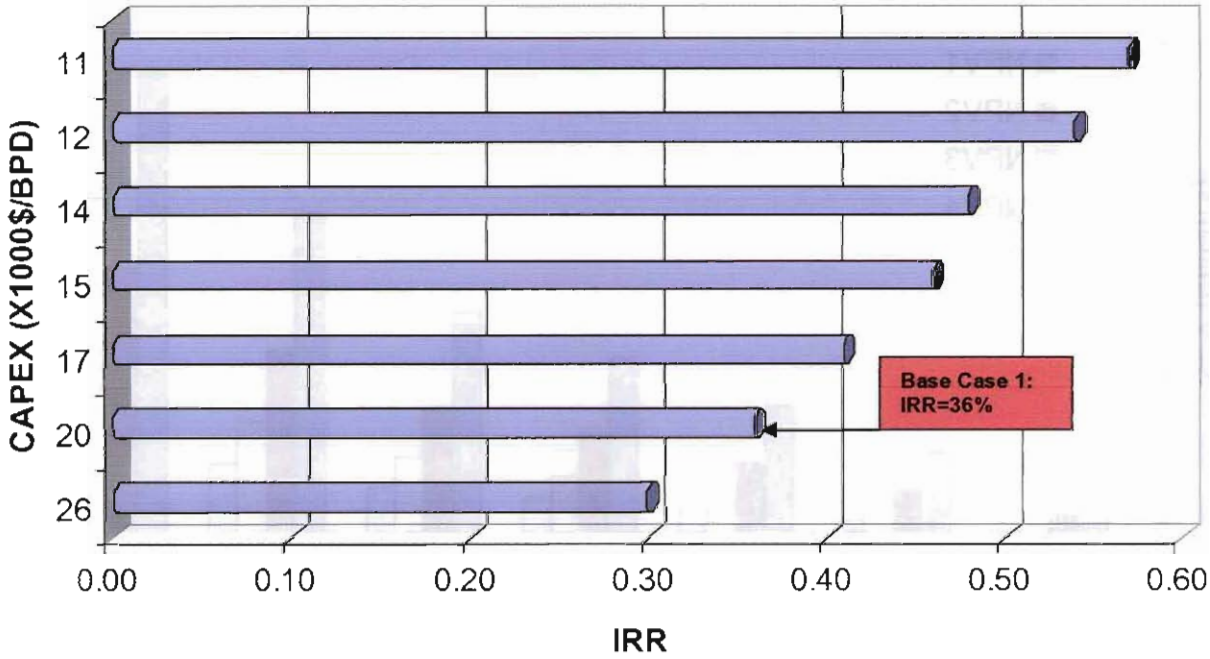

Fig 4.4: Chart showing IRRs for various CAPEX values for Base case scenario one

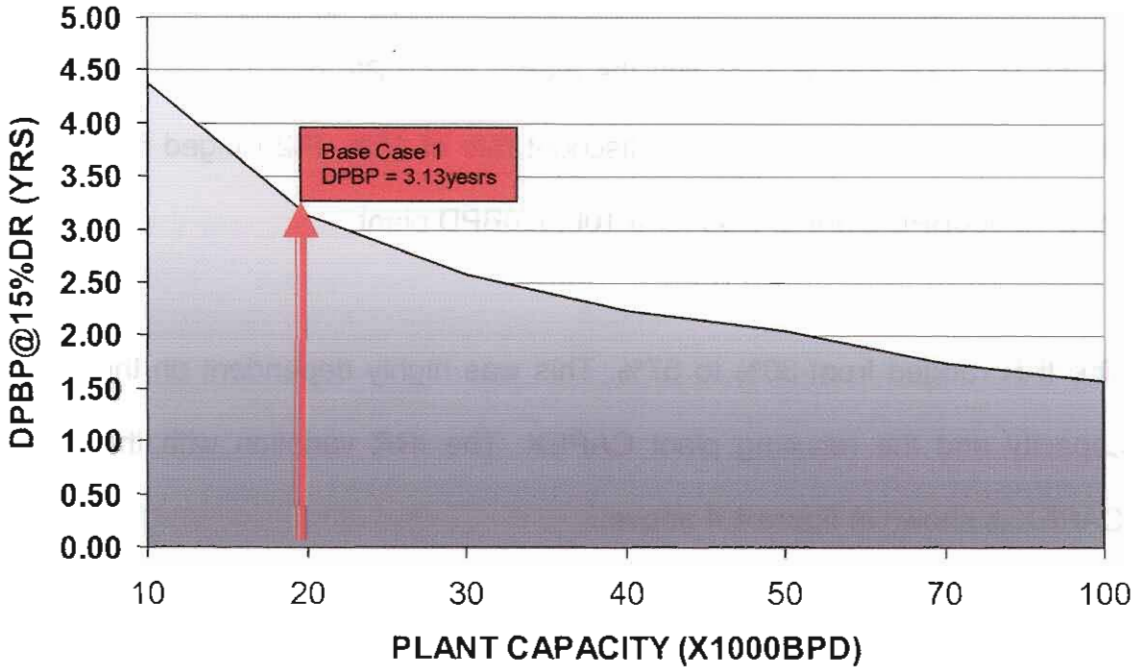

Fig 4.5: Chart showing DPBP for various Plant Capacities for Base case scenario one

The CAPEX trend shown in figure 4.1 for base case scenario one dropped to a value as low as $11,000/BPD when a higher plant capacity of up to 100,000BPD was considered using the economy of scale relationship. This is a demonstration of the effect of economy of scale on the Plant CAPEX.

For all the discounts rates used for the analysis in this base case, the NPVs were positive. The lowest being a NPV4 of $35.2 million obtained for a 10,000BPD plant (i.e. at the highest discount rate of 25%). At the base case discount rate of 15%, the NPV2 for the range of plant capacities were positive ranging from $216 million to $5.53 billion. This is shown in figure 4.2. This implies that the project is viable for all the scenarios considered in this base case.

The PIs in figure 4.3 also returned the same accept-reject result as the NPV all the PIs were above 1.00 with the lowest being PI4 of 1.14 (i.e. at a 25% discount rate). At the base case discount rate of 15%, PI2 ranged from 1.83 for a 10,000BPD plant to 3.90 for a 100,000BPD plant.

The IRR ranged from 30% to 57%. This was highly dependent on the plant capacity and the resulting plant CAPEX. The IRR variation with the plant CAPEX is shown in figure 4.4 above.

The Discounted Payback Period (DPBP) shown in figure 4.5 ranged from 4.38years for a 10,000BPD plant to 1.58years for a 100,000BPD plant with the base case having a payback period of approximately 3.13years. See appendix 7.4 for table of results.

Generally speaking the overall analysis for this case scenario is very favourable for the Floating GTL plants. It shows an all round acceptance result for all the case scenarios considered.

4.2.2 BASE CASE SCENARIO TWO

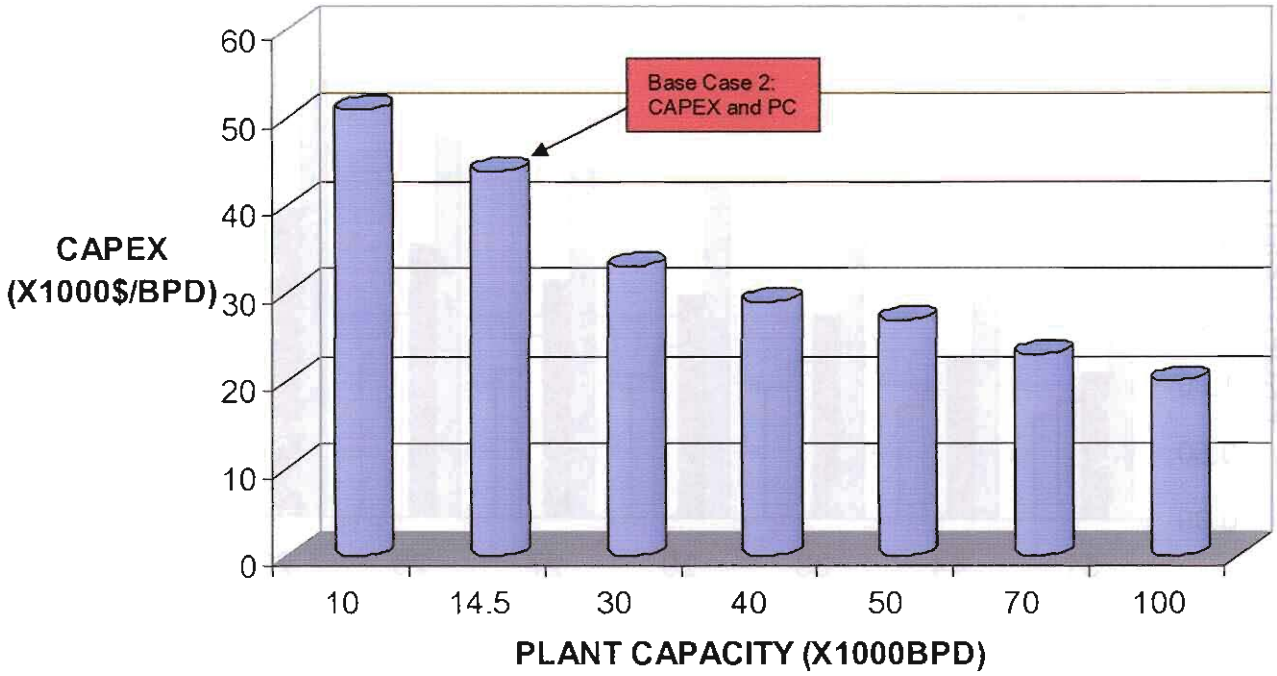

Fig 4.6: Chart showing Economy of Scale relationship for base case scenario two

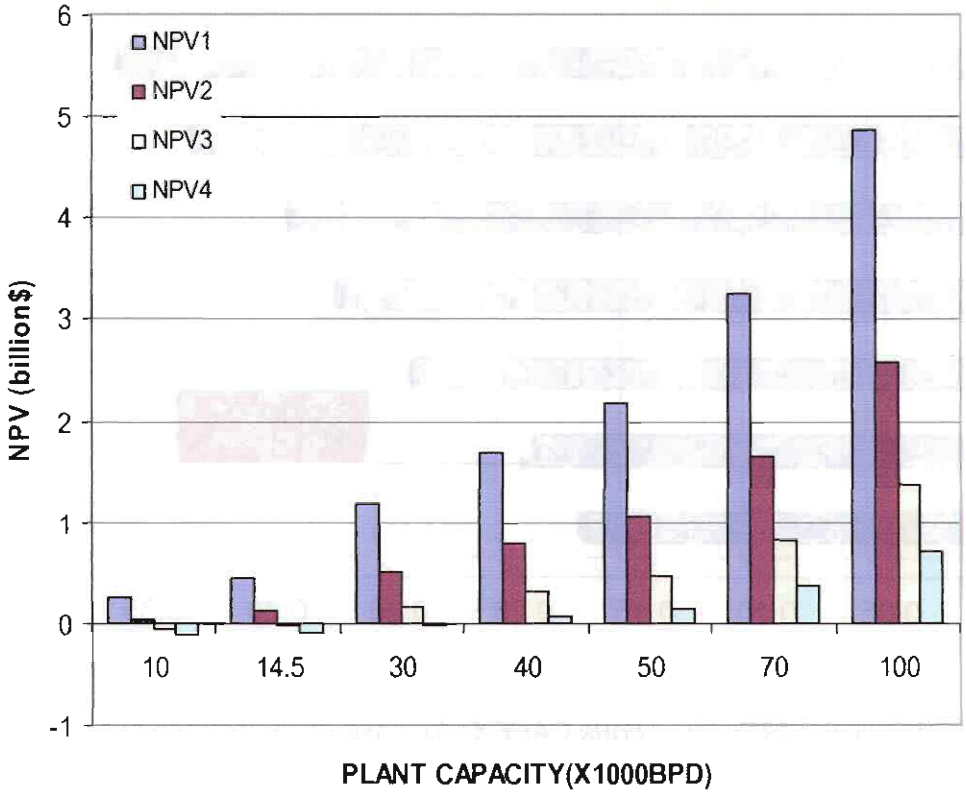

Fig 4.7: Chart showing NPVs for varying Plant Capacities for base case scenario two

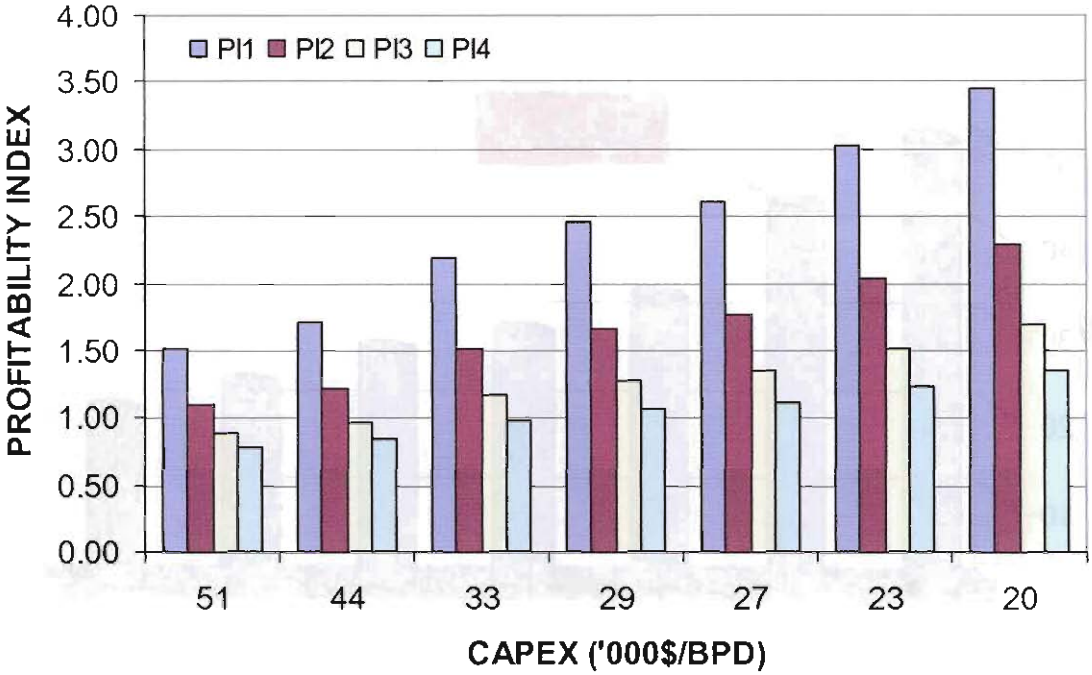

Fig 4.8: Chart showing PIs for varying Plant CAPEXs for base case scenario two

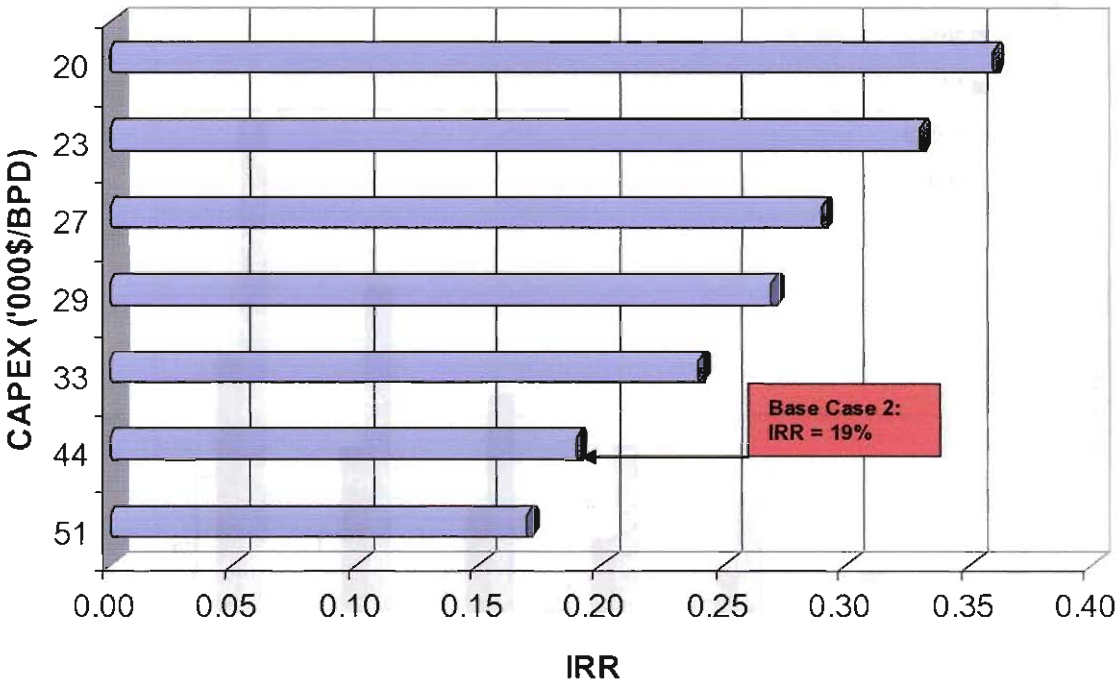

Fig 4.9: Chart showing IRRs for various CAPEXs for base case scenario two

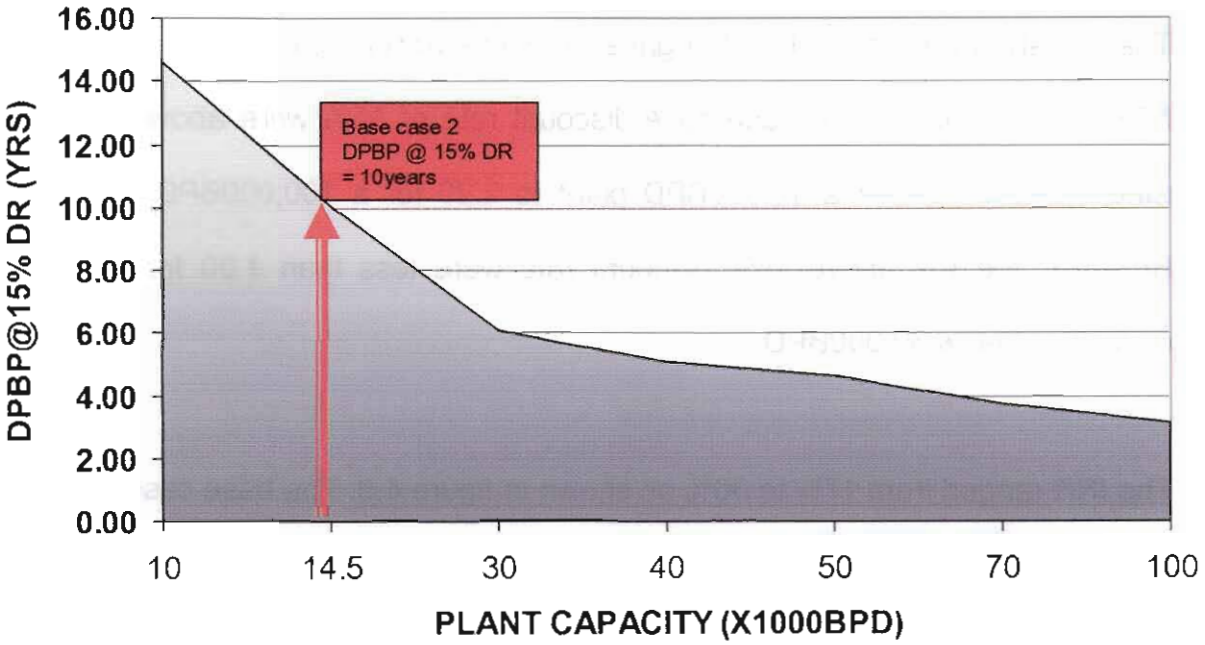

Fig 4.10: Chart showing DPBP for varying Plant Capacities for base case scenario two

The CAPEX distribution shown in figure 4.6 for a base case of $44,000/BPD for a 14,500BPD plant dropped as the plant capacity increased. The lowest being $20,000/BPD when a higher plant capacity of up to 100,000BPD was considered using the economy of scale relationship. However, CAPEX increased significantly to $51,000/BPD when a smaller plant of 10,000BPD capacity was considered.

The results generated in table 4.7 shows the NPVs for the various plant Capacities and CAPEXs. The NPV3 and NPV4 representing NPVs at 20% and 25% discount rates are negative for 10,000BPD and 14,500BPD plants. However, the NPVs were positive for all the other scenarios in this base case. At the base case discount rate of 15%, NPV2 for the range of plant capacities were positive ranging from $43.8 million to $2.57 billion.

The PIs shown in figure 4.8 also gave the same accept-reject result as the NPV. All the PI2s at the base case discount rate of 15% were above 1.00 ranging from 1.09 for a 10,000BPD plant to 2.29 for a 100,000BPD plant. However, the PIs above 15% discount rate were less than 1.00 for plant capacities below 30,000BPD.

The IRR ranged from 17% to 36% as shown in figure 4.9. The base case IRR is 19% as indicated on the chart. This was highly dependent on the plant capacity and the resulting plant CAPEX. Also the Discounted payback period ranged from 14.6years for a 10,000BPD plant to 3.13years for a 100,000BPD plant. The DPBP at the base case was 10.1years. See appendix 7.4.

4.3 SENSITIVITY ANALYSIS

BC1A, BC1B, BC2A and BC2B represent the four cases for sensitivity analysis described in the previous chapter. BC1A and BC1B are base cases one A and One B respectively. These notations represent 20,000BPD (BC1A) and 70,000BPD (BC1B) plants with corresponding CAPEX values of $20,000/BPD and $12,000/BPD respectively, derived using the economy of scale concept based on Syntroleum's quote.

On the other hand, BC2A and BC2B are Base Case Two A and Base Case Two B respectively. These notations represent 14,500BPD (BC2A) and 70,000BPD (BC2B) plants with CAPEX of $44,000/BPD and $23,000/BPD respectively based on Statoil's survey. The feedstock cost is expressed per barrel of product for ease of calculation. Since both technologies have the same conversion rates.

The IRRs and NPVs generated from the sensitivity analysis are also presented using the BC notation. For example, IRR_BC1A represent IRR for Base case one A and NPV_BC2B represent NPV for Base case two B. The NPVs are at the base case discount rate of 15%.

4.3.1 FEEDSTOCK COST

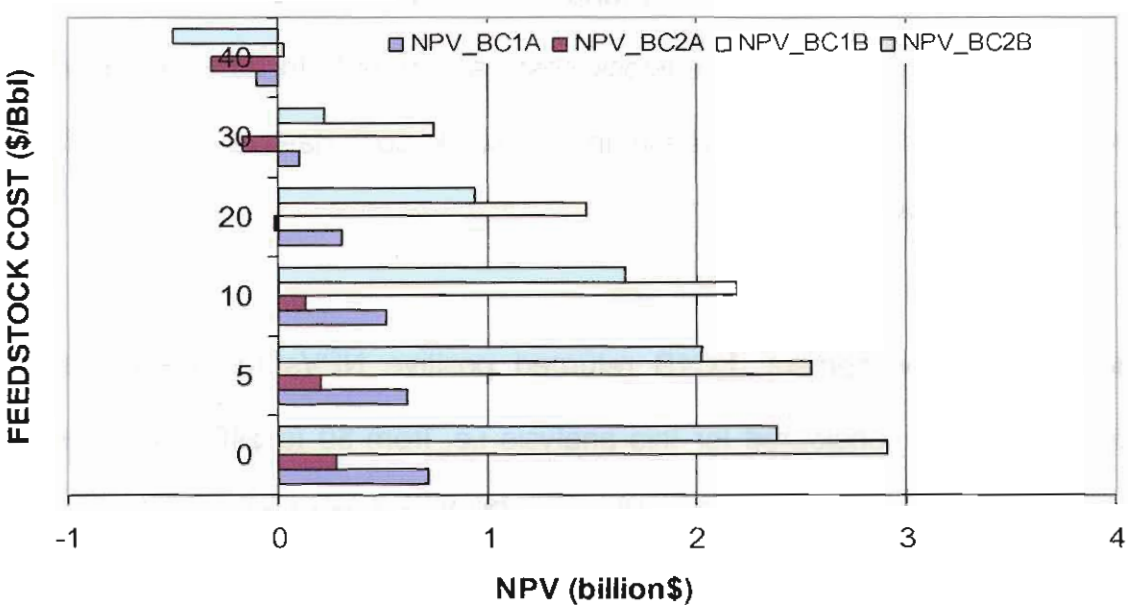

Fig 4.11: Chart showing NPV sensitivity to variations in Feedstock Cost

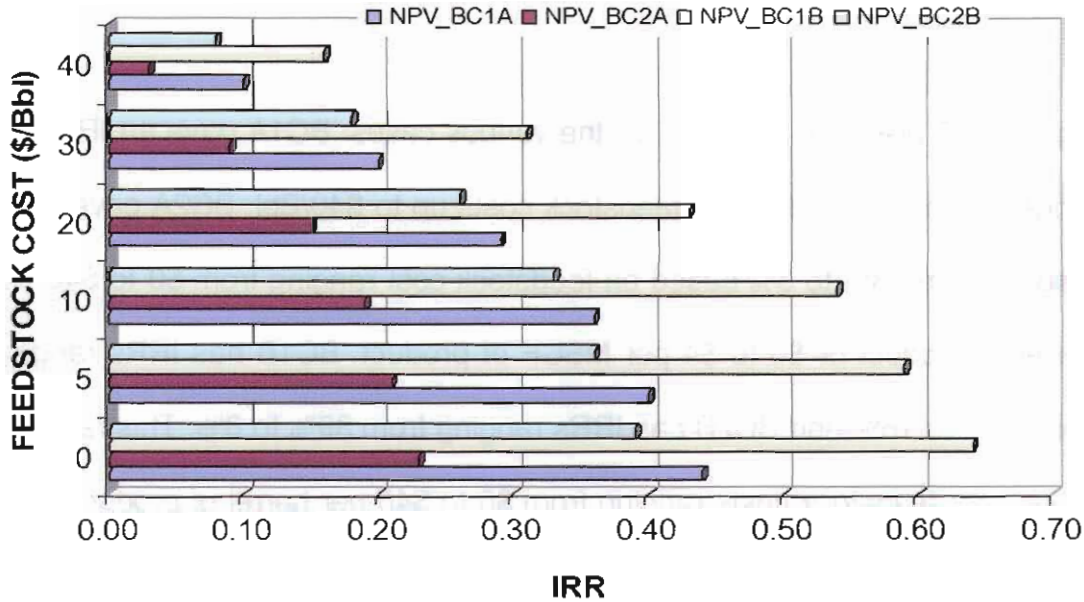

Fig 4.12: Chart showing IRR sensitivity to variations in Feedstock Cost

From figure 4.11, BC1A (Syntroleum's design) returned negative NPVs at a feedstock cost of $40/Bbl of product ($4 per MSCF of gas) and above but returned positive NPVs for feedstock cost less than $40 per barrel of product. On the other hand BC2A (Statoil's design) gave negative NPV for feedstock cost up $20 per barrel of product or $2 per MSCF of gas and above but gives a positive NPV for feedstock cost ranging from $0 to $1 per MSCF. For both cases, a 50% increase in feedstock cost gave a 14% to 26% decrease in NPV, whereas a 100% increase in feedstock cost gave a 40% to 60% decrease in NPV.

In another development, BC1B returned positive NPVs for the range of feedstock cost considered for this analysis i.e. from $0 to $40 per barrel of product ($0 to $4 per MSCF). Whereas BC2B returned positive NPVs for feedstock cost up to $30 per barrel of product ($3 per MSCF) but for feedstock cost greater than that the NPVs were negative. This is also presented in figure 4.11.

Figure 4.12 presents the IRRs for the various cases. BC1A gave an IRR that ranged from 44% to 10% for feedstock costs up to $40/Bbl. BC2A gave IRRs ranging from 23% to 3% based on feedstock cost ranging from $0 to $40 per barrel of product or $0 to $4 per MSCF of product. BC1B has IRRs ranging from 64% to 16% and BC2B has IRRs ranging from 39% to 8%. This range of IRRs is for feedstock costs ranging from $0 to $40 per barrel of product or $0 to $4 per MSCF of gas.

See appendix 7.4 for table of results.

4.3.2 OPERATING COST

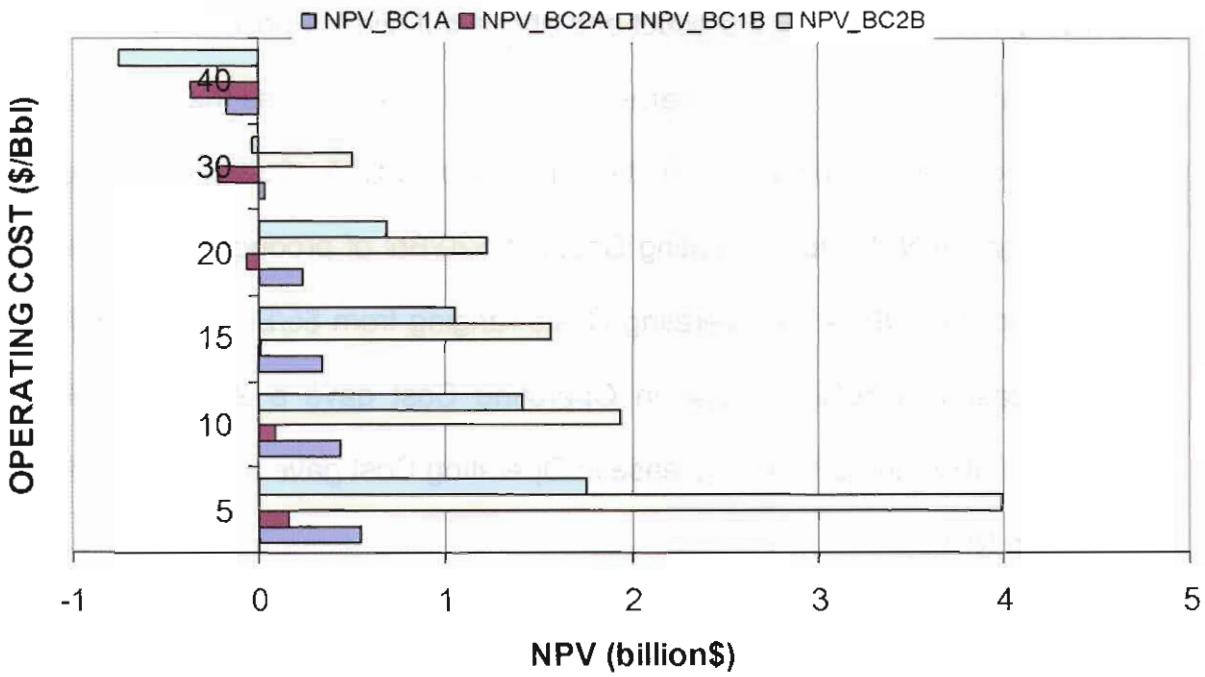

Fig 4.13: Chart showing NPV sensitivity to variations in Operating Cost

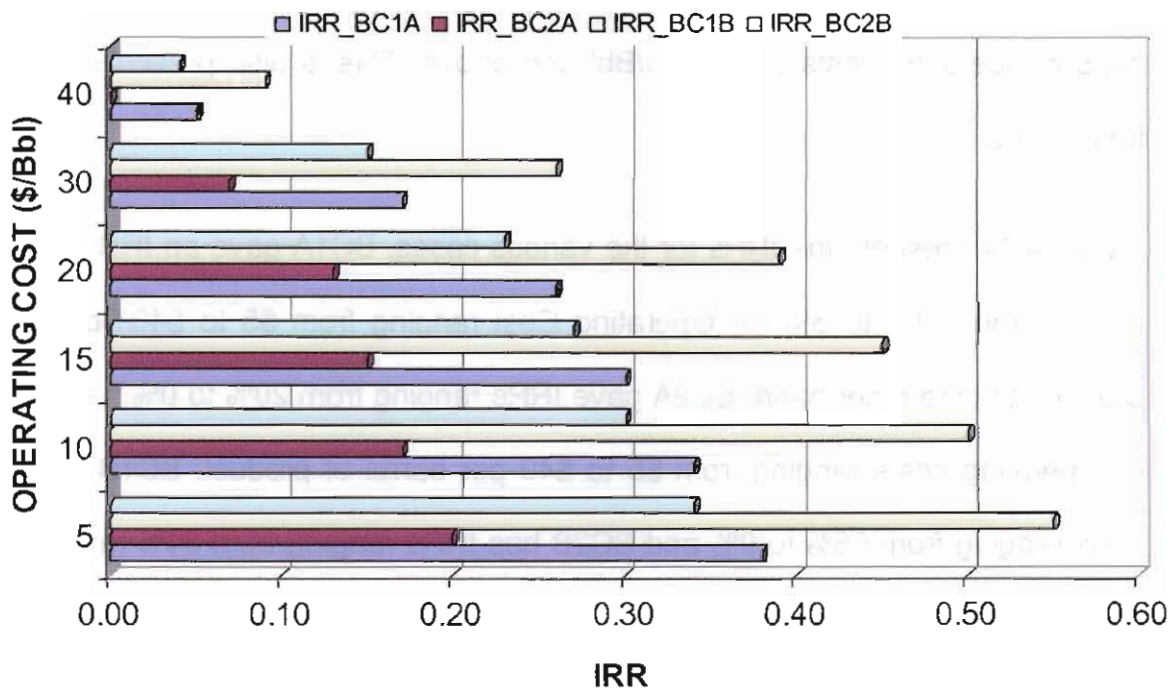

Fig 4.14: Chart showing IRR sensitivity to variations in Operating Cost

BC1A (Syntroleum's design) as shown in figure 4.13 gave a negative NPV at a operating cost of $40/Bbl of product and above but gives a positive NPV for feedstock cost less than $40 per barrel of product. This was also the case for the feedstock costs variations. On the other hand BC2A (Statoil's design) gives a negative NPVs for Operating Costs of $20/Bbl of product and above but gives positive NPVs for Operating Costs ranging from $5/Bbl to $15/Bbl. For both cases, a 50% increase in Operating Cost gave a 23% to 24% decrease in NPV, and a 100% increase in Operating Cost gave a 46% to 48% decrease in NPV.

In another development, BC1B gave positive NPVs for the range of operating cost considered for this analysis up to $30/Bbl of product and does not support Operating Costs up to $40/Bbl of product. Whereas BC2B gave positive NPVs for Operating Cost up to $20/Bbl of product but for does not support operating costs up to $30/Bbl and above. This is also presented in figure 4.13.

Figure 4.14 presents the IRRs for the various cases. BC1A gave an IRR that ranged from 38% to 5% for Operating Cost ranging from $5 to $40/Bbl of product. On the other hand, BC2A gave IRRs ranging from 20% to 0% based on operating costs ranging from $5 to $40 per barrel of product. BC1B has IRRs ranging from 55% to 9% and BC2B has IRRs ranging from 34% to 4%. These ranges of IRRs are for operating costs ranging from $5 to $40 per barrel of product.

See appendix 7.4 for table of results

4.3.3 PRODUCT PRICE

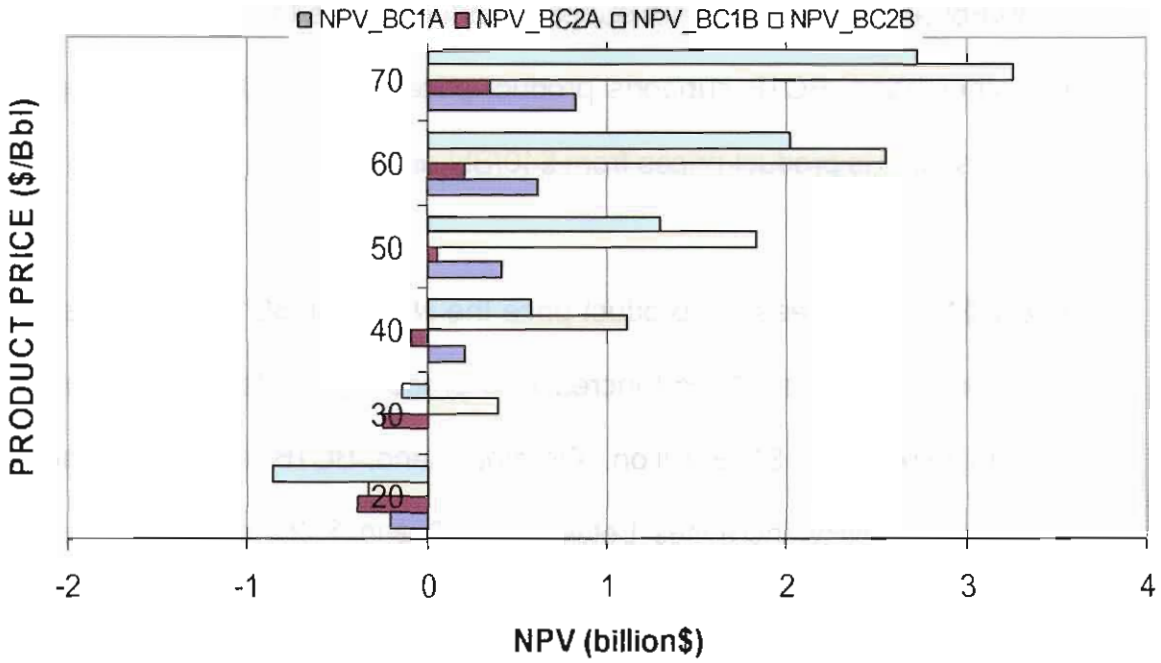

Fig 4.15: Chart showing NPV sensitivity to variations in Product Price

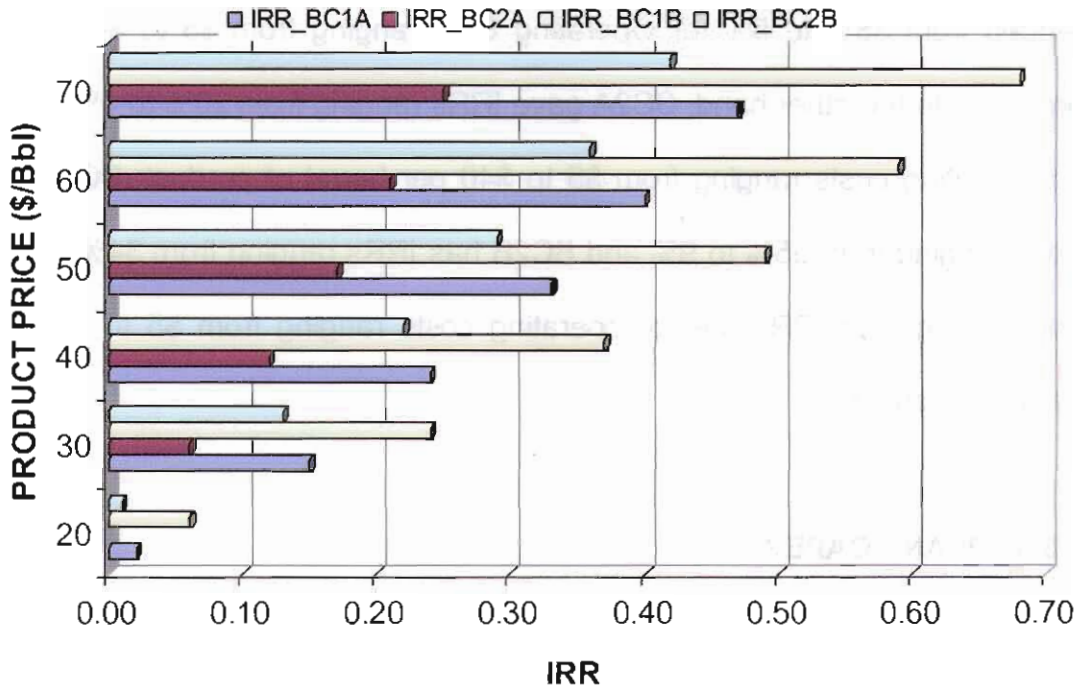

Fig 4.16: Chart showing IRR sensitivity to variations in Product Price

As shown in figure 4.15 above, BC1A does not support product prices lower than $30/Bbl and BC2A does not support product prices lower than $50/Bbl. On the other hand, BC1B supports product prices from $30/Bbl and above and BC2B supports product prices from $40/Bbl and above.

For every $10/Bbl increase in product price the NPVs for BC1A increases by $215 million, whereas a $10/Bbl increase in product price for BC2A causes the NPV to increase by $149 million. On other hand, BC1B and BC2B (same capacities) gave NPV increases between $710 and $721 million for every $10/Bbl increase in product price. This is shown in table 7.11, see appendix 7.4

Figure 4.16 presents the IRRs for the various cases. BC1A gave an IRR that ranged from 38% to 5% for Operating Cost ranging from $5 to $40/Bbl of product. On the other hand, BC2A gave IRRs ranging from 20% to 0% based on operating costs ranging from $5 to $40 per barrel of product. BC1B has IRRs ranging from 55% to 9% and BC2B has IRRs ranging from 34% to 4%. These ranges of IRRs are for operating costs ranging from $5 to $40 per barrel of product.

4.3.4 PLANT CAPEX

For this analysis, the base cases CAPEX are varied as discussed in Chapter three. This is to account for increase or decrease in plant CAPEX that might occur based on several factors already discussed. An example is the rising steel prices, the development of the ceramic membranes, and so on.

The BC notation has been adopted to represent the Base Cases. For example, BC1_1 represents base case 1 scenario 1, BC2_1 represents Base Case 2 scenario 2, and so on. This is shown in Table 4.13, with the base cases highlighted in green.

	BC1_1 (BC=$30,000/BPD)		BC1_2 (BC=$50,000/BPD)		BC1_3 (BC=$60,000/BPD)	
PC (MBPD)	CAPEX (M$/BPD)	NPV (MM$)	CAPEX (M$/BPD)	NPV (MM$)	CAPEX (M$/BPD)	NPV (MM$)
10	40	32	66	-147	79	-236
20	30	202	50	-73	60	-210
30	26	386	43	35	51	-130
40	23	598	38	185	46	-36
50	21	816	35	334	42	93
70	18	1290	30	709	36	419
100	16	1980	26	1290	32	875

Table 4.1: Showing Base case 1 plant CAPEX variations scenario

	BC2_1 (BC=$30,000/BPD)		BC2_2 (BC=$50,000/BPD)		BC2_3 (BC=$60,000/BPD)	
PC (MBPD)	CAPEX (M$/BPD)	NPV (MM$)	CAPEX (M$/BPD)	NPV (MM$)	CAPEX (M$/BPD)	NPV (MM$)
10	35	67	58	-92	70	-174
14.5	30	147	50	-53	60	-153
30	22	469	37	159	45	-6
40	20	680	33	322	40	130
50	18	919	31	472	37	265
70	16	1380	27	853	32	612
100	14	2110	23	1490	28	1150

Table 4.2: Showing Base case 2 plant CAPEX variations scenario

4.3.4.1 BASE CASE ONE (BC1)

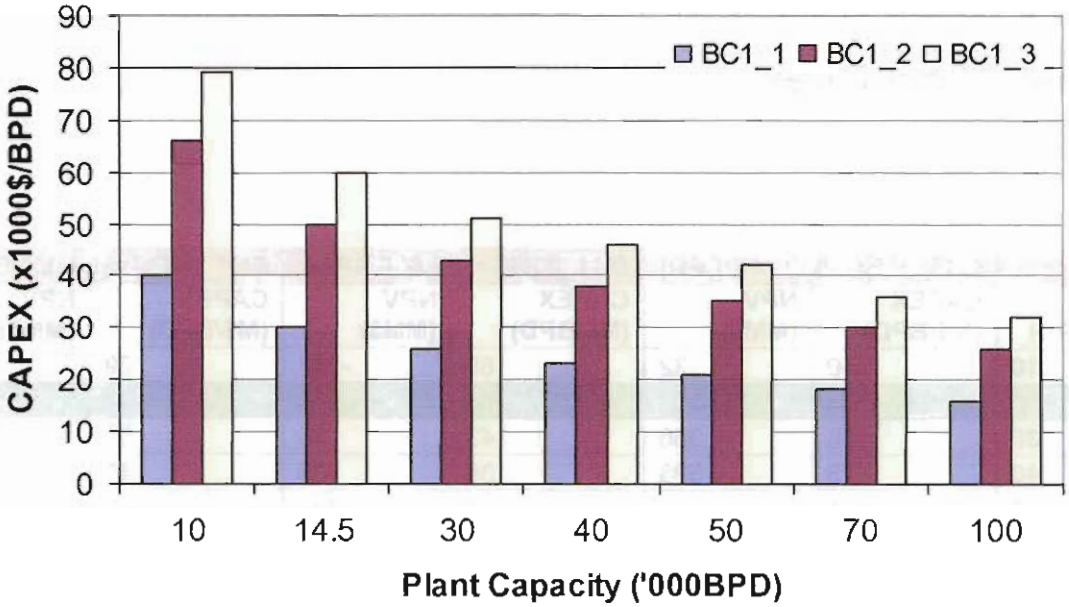

Figure 4.17: Chart showing CAPEX plotted against the Plant Capacity for BC2

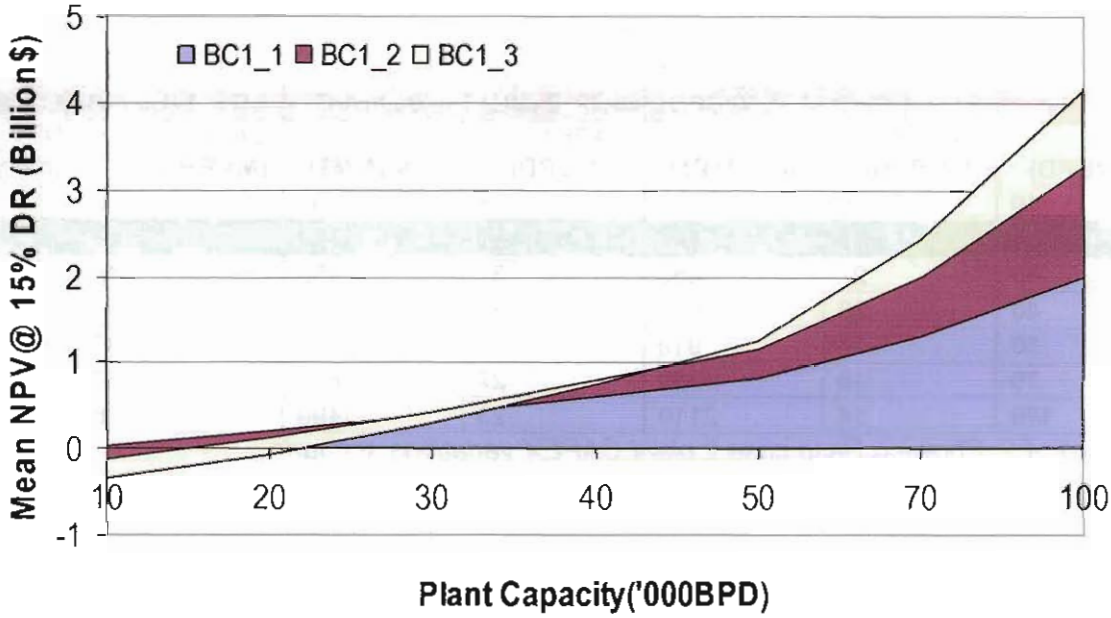

Figure 4.18: Chart showing NPV plotted against the Plant Capacity for BC1

The CAPEX estimates shown in figure 4.17 were calculated using the economy of scale concept for the CAPEX base cases considered for this sensitivity analysis.

As shown in table 4.1 and figure 4.18, BC1_1 gave positive NPVs for the range of plant capacities considered for this analysis. BC1_2 gave negative NPVs for the base case (20,000BPD) and for 10,000BPD plant but supports a 30,000BPD plant and other plants of higher capacities greater than 30,000BPD. On the other hand, BC1_3 can only support plant capacities greater than 40,000BPD.

4.3.4.2 BASE CASE TWO (BC2)

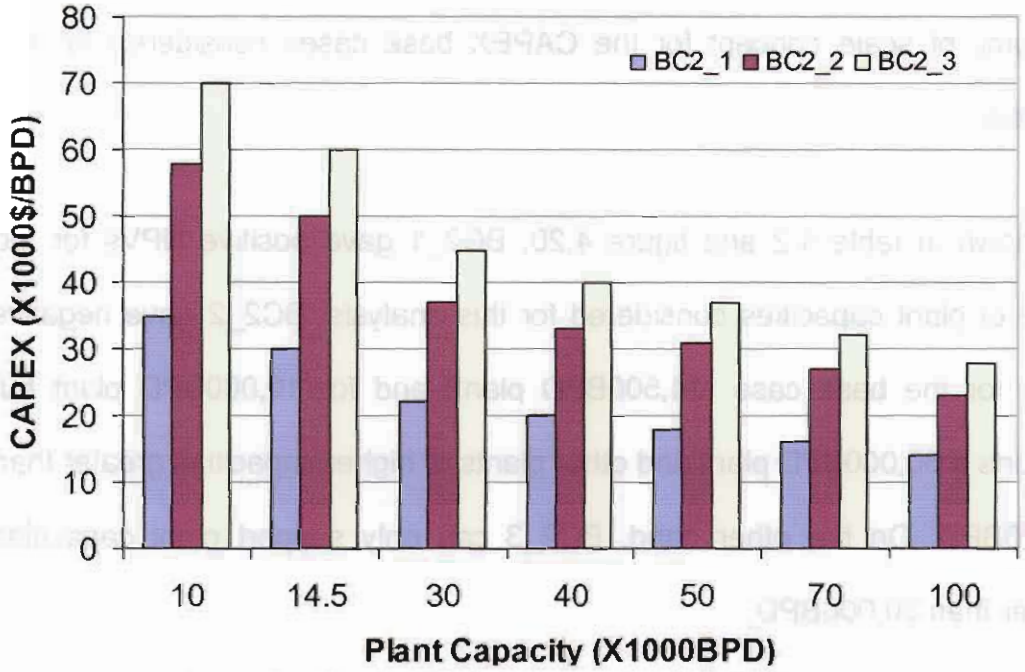

Figure 4.19: Chart showing CAPEX plotted against the Plant Capacity for BC2

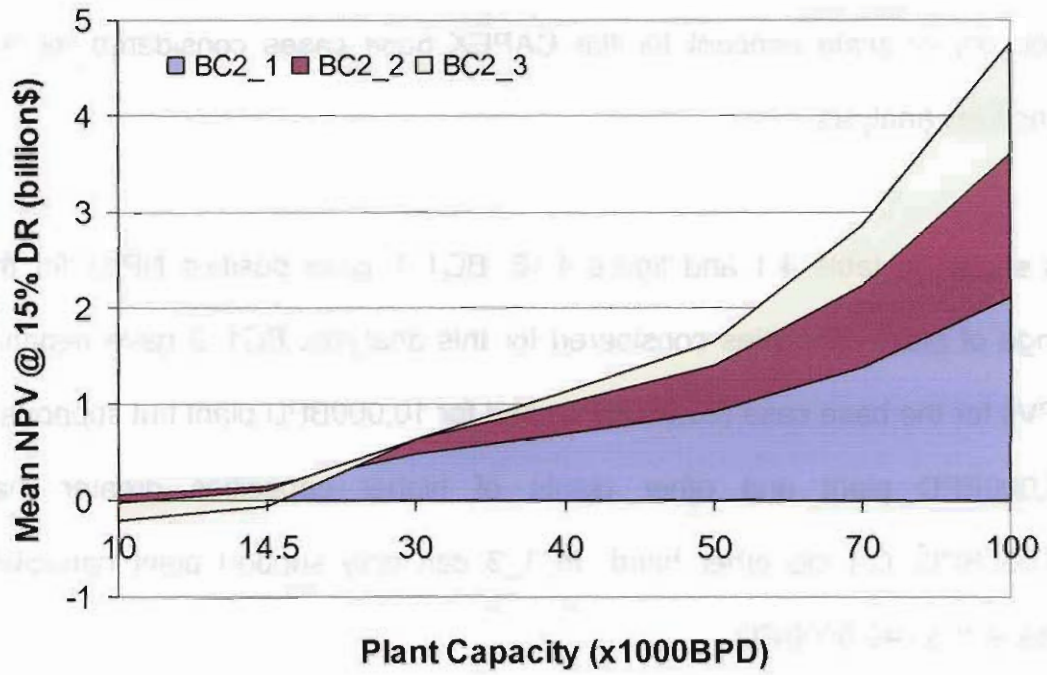

Figure 4.20: Chart showing CAPEX plotted against the Plant Capacity for BC2

The CAPEX estimates shown in figure 4.19 were calculated using the economy of scale concept for the CAPEX base cases considered for this analysis.

As shown in table 4.2 and figure 4.20, BC2_1 gave positive NPVs for the range of plant capacities considered for this analysis. BC2_2 gave negative NPVs for the base case (14,500BPD plant) and for 10,000BPD plant but supports a 30,000BPD plant and other plants of higher capacities greater than 30,000BPD. On the other hand, BC2_3 can only support plant capacities greater than 30,000BPD.

4.3.5 BREAK-EVEN ANALYSIS

The results generated from the break-even analysis for the base case scenarios considered in this study are presented in tables 4.3 and 4.4 below:

BASE CASE ONE (SYNTROLEUM)			
PC (X1000BPD)	CAPEX (X1000$/BPD)	CASH B-E POINT (BCF)	ACCT B-E POINT (BCF)
10	26	67.5	70.2
20	20	104	108
30	17	133	138
40	15	156	162
50	14	182	189
70	12	218	227
100	11	286	297

Table 4.3: showing break-even points for different plant capacities for base case one

BASE CASE TWO (STATOIL)			
PC (X1000BPD)	CAPEX (X1000$/BPD)	CASH B-E POINT (BCF)	ACCT B-E POINT (BCF)
10	26	133	138
20	20	166	172
30	17	257	267
40	15	301	313
50	14	351	365
70	12	418	435
100	11	520	540

Table 4.4: showing break-even points for different plant capacities for base case two

4.4 DISCUSSIONS OF RESULTS

Recall that base case economic assumptions used for this study are:

- Plant life with depreciation period 25 years and construction period 3 years
- Salvage value is assumed to be equal to decommissioning cost
- Corporate tax rate is 29%
- Gas price $1 per MSCF ($10 per barrel of product)
- crude oil price $50 per barrel, and
- Synthetic fuel prices are crude oil price plus premium prices in which premium price was generally assumed to be $5 per barrel of product.
- Base case discount rate used is 15%.

The estimated cost for a floating GTL plant for base case scenario 1 (Syntroleum's case) with capacity 10,000BPD synthetic fuels is $260 million;

based on inside battery limit, corresponds to $26,000 per BPD. Estimated cost of the largest capacity considered for this scenario with capacity of 100,000BPD synthetic fuels is approximately $11,000 per BPD. On the other hand, for base case scenario 2 (Statoil's case) a floating GTL plant with a 10,000BPD synthetic fuels capacity is $510 million; based on inside battery limit, corresponds to $51,000 per BPD and a 100,000BPD plant is approximately $20,000 per BPD.

Synthesis gas production unit including air separation is the most responsible for about 60% of total cost. The inclusion of the air separation unit is the main determining factor responsible for the difference in cost of a plant of the same capacity for the two case scenarios. We should note that the economic aspects of offshore floating GTL plants are similar to that of onshore GTL plants but are different from traditional petroleum refining. In GTL, the plant cost is capital intensive with lower cost of raw material, thus the service of capital is the major components to products cost, while it is contrary to petroleum refining.

Typical results of profitability analyses for both base case scenarios were interpreted in the previous section. Both scenarios considered returned positive NPVs based on the base economic assumptions used for this analysis. Although base case scenario 2 returned negative NPVs for discount rates higher than the base economic assumed discount rate for some plant capacities. At 20% discount rate the return was negative for 10,000BPD and 14,500BPD plants and at 25% discount rate it returned negative NPVs for 10,000, 14,500 and 30,000BPD plants.

Figure 4.11 to figure 4.16 shows the impact of wellhead gas price, synthetic fuel (product price), operating costs and plant CAPEX on Internal Rate of Return (IRR) and Net Present Value (NPV). Based on product price at $55 per barrel, economic analysis revealed that base case scenario 1 of the floating GTL plant route is feasible for gas field with modest gas prices (~ 0 to 3 $/MSCF) with a 20,000BPD plant capacity, corresponding to ~1-3 TCF of gas reserve (see Figure 4.11 and appendix 4).

As an illustration, for the same product price of $55 per barrel, base case scenario 2 for gas fields with modest gas price is feasible at minimum plant capacity of 20,000BPD at gas price less than or equal to $1/MSCF (see Figure 4.13). For plant capacities up to 70,000BPD, base case scenario 2 is feasible at gas price up to $3/MSCF.

The break-even analysis results in tables 4.3 and 4.4 shows that the break-even points for both base case scenarios considered in this study, representing the minimum gas reserves for the project to break-even. For base case one (Syntroleum's case), the plant will break-even on an accounting basis for gas reserves greater than the breakeven point of 70.2BCF for a 10,000BPD plant. Also, for the maximum plant capacity (100,000SCF) considered for base case one, the plant will break-even for gas reserves greater than 297BCF.

On the other hand, for Statoil's case the project will break-even on accounting basis for gas reserves greater than 138BCF for a 10,000BPD plant. Also, for plant capacities up to 100,000BPD the plant will break-even for gas reserves greater than 540BCF.

Sensitivity analysis results for base case scenario 1 and 2 can be summarized in Figure 4.21 and figure 4.22. In general, the impact of gas price is the most sensitive compared to other parameters. However, product price, operating cost, plant CAPEX and plant capacity also have significant impacts.

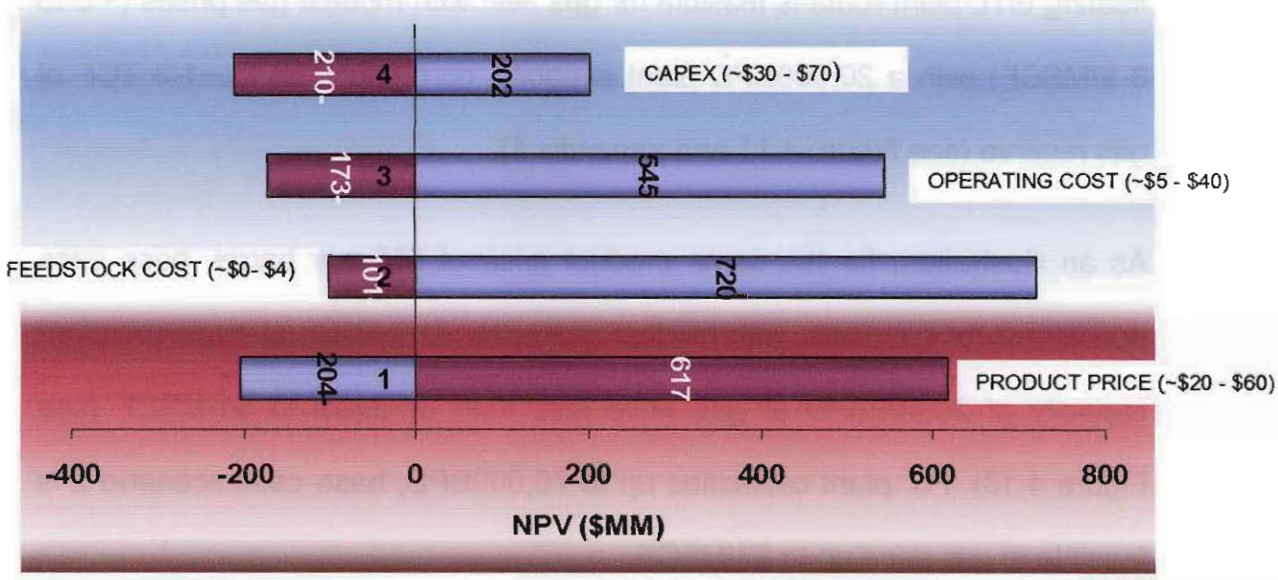

Figure 4.21: Chart showing a summary of Sensitivity Analysis for base case scenario 1

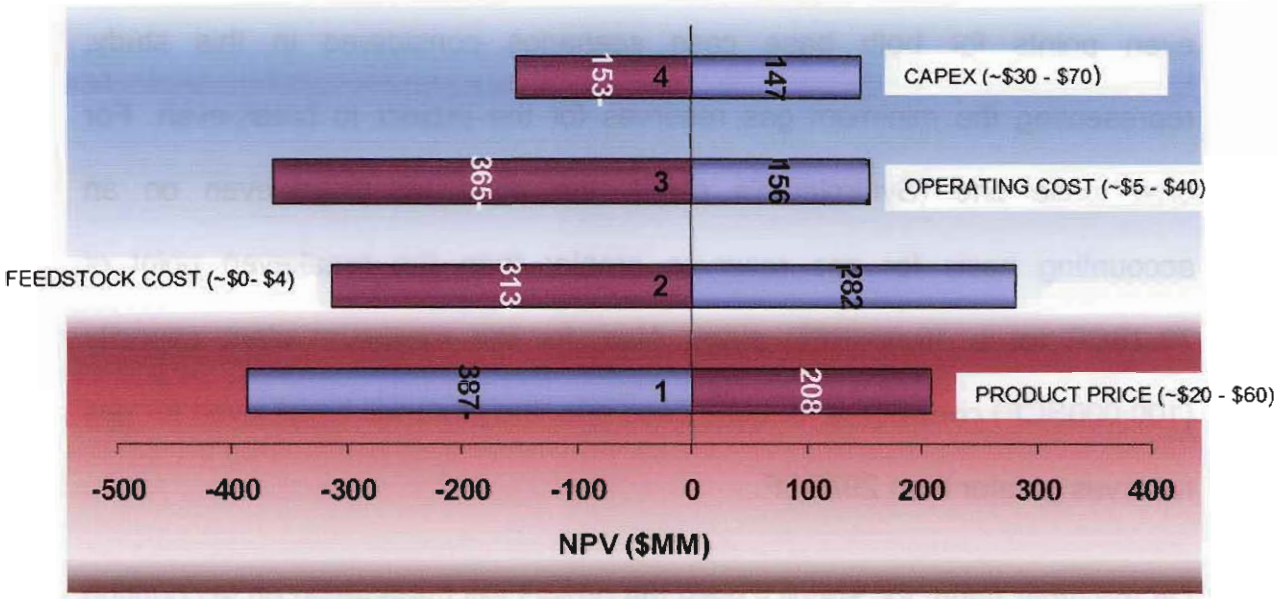

Figure 4.22: Chart showing a summary of Sensitivity Analysis for base case scenario 2

Despite high operating costs, it is interesting that high crude oil price and reduction trend in capital expenditure (CAPEX) for stand alone Floating GTL

plant to below $20,000/BPD in the next few years, opens window of opportunity for GTL application for offshore stranded gas reserves (associated and non-associated).

4.5 VALIDATION OF RESULTS

In an attempt to test the soundness of the EV model, an existing data for a field in the Niger Delta region of Nigeria currently in production has been used. At the said field, associated natural gas produced during crude oil production is currently being flared daily. The field data is used to test the viability of a Floating GTL plant, if deployed to operate on the field based on the existing gas volume currently produced daily.

The Meren I production facility is located 36km (22.5 miles) offshore from the Base within an OML at Nigerian grid and geographic coordinates N196,103.00, E274,381.00 and 05-46-25.80N, 04-53-38.85E, respectively. The facility is about 15km (9.4 miles) from the nearest shoreline in 16m (53 feet) of water.

The Meren1 production facility consists of one 8-pile production platform, a 4-pile utility and compression platform and one 4-pile quarters platform, all of which are bridge connected, and a flare stack mounted on a tripod. In addition to the production complex, there are 15 well protector platforms (well jackets) that feed to the Meren 1 production platform, which contain a total of 75 producing and shut-in well streams.

The Meren 1 production platform is designed for three-phase separation of up to 100,000 BFPD and 90,000 MCF/D from 15 of the well jackets in the Meren

Field. ***The gas is separated and flared at the remote flare pile.*** The production facilities at Meren 1 are designed to dehydrate up to 100,000 BFPD. Up to 25,000 BWPD of produced water can be treated and disposed at Meren 1. The treated crude is pumped and then co-mingled with all of the Parabe Area crude, then sent to the Valve platform through a 32km (20 miles), 660mm (26") pipeline. It is also possible to ship the crude to the Valve platform via a 32km (20 miles), 406mm (16") pipeline, if the need so arises.

Additional background information on the Meren 1 Field is listed below in table 4.5: (also see appendix 7.8)

No. of producing/Shut-in wells	66/71
Current oil production rate (May, 2003)	82,500 BOPD
Current water production rate (May, 2003)	28,000 BWPD
Current gas production rate (May, 2003)	86,750 MCF/D

Table 4.5: showing background information on Meren 1 production facility

Based on the information above the gas volume is equivalent to 8675 barrels of GTL product per day (i.e. 10,000 SCF ≡ 1 Barrel of Product based on Sasol and Syntroleum's GTL process), this is approximately 8700 barrels of GTL products per day. To produce this volume of GTL product a minimum of 8,700BPD Floating GTL plant with the capacity for expansion can be deployed to convert the flared gas into high energy liquids/products.

The EV model is used to test the viability of a Floating GTL plant producing approximately 8700 barrels of GTL product per day for such a venture on a standalone basis using the base case economic assumptions used for this study. Recall the base economic assumptions:

OC = $6.5/Barrel

FC = $10/Barrel or $0/barrel

DR = 15%

TR = 29%

D = 0.04 CAPEX per annum

PP = $55/Barrel

Two sets of feedstock cost will be considered. A cost at $1 per MSCF and a no-cost value will be tested, since the gas had been initially considered worthless. The test will be based on two case scenarios representing Syntroleum's design and Statoil's design.

The results from the EV model are tabulated below in table 4.6 and 4.7

SYNTOLEUM'S TECHNOLOGY. CAPEX = $28,000/BPD		
FEEDSTOCK COST	*$1/MSCF*	*NO COST = $0/MSCF*
NPV ($MM)	177	266
IRR (%)	28	34
PI	1.73	2.09
DPBP (YRS)	4.75	3.60

Table 4.6: validation results based on Syntroleum's technology and quote

STATOIL'S TECHNOLOGY. CAPEX = $54,000/BPD		
FEEDSTOCK COST	*$1/MSCF*	*NO COST = $0/MSCF*
NPV ($MM)	21.4	111
IRR (%)	16	20
PI	1.05	1.24
DPBP (YRS)	17.5	9.50

Table 4.7: validation results based on Statoil's technology and quote

The CAPEX for the two scenarios were calculated using the economy of scale relationship with reference to the base case CAPEXs. The result shows an all round acceptance based on both existing technologies. The natural gas production from this field could have been put to great use by getting a monetary value for it and at the same saving the environment from further degradation.

This result when taken back in time (when crude oil price averaged about $28 per barrel with feedstock cost fixed at $1/MSCF) affirms claims made by Syntroleum's business development manager (Hutton 2003) that it is doubtful that the offshore Floating GTL plant can be profitable on a stand alone basis for capacities smaller than 14,000BPD. This statement also conforms to the sensitivity analysis results previously obtained from this study.

But testing this case on the EV model with a no-feedstock cost situation and a CAPEX of $20,000/BPD based on Syntroleum's technology showed an all round investment acceptance with a 20% IRR.

In conclusion, the EV model has been tested with a real life situation and the result shows the flexibility exhibited by the model.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.1 CONCLUSION

5.1.1 Introduction

Environmental and energy security/conservation pressures (already discussed), and the desire to realise value from oil and gas operations, have been identified as key drivers for recent research into the application of technologies such as Floating GTL process for the conversion of offshore stranded gas assets. However, a key barrier that could hinder increased stranded gas utilization for the Floating GTL monetisation option is regulatory uncertainty, and lower energy price especially crude oil based fuels.

The result of this study shows seeming evidence that offshore deployment of Floating GTL plants has a bright future and it fits into a general trend in favour of developing the GTL industry. This innovative solution will now enable exploitation of offshore stranded gas assets which are geographically widely dispersed and range from small to medium inventories of associated gas, to major non-associated gas fields remote from markets.

By focusing the floating GTL commercialisation route on a niche, in this case offshore stranded gas, the chance of success is increased not necessarily by directly competing with established technologies. This new market is aimed to provide support for national security of energy supply, energy consumption in more efficient way and more environmentally responsible manner, cleaner alternative fuels, and creation of high gas values added.

Also, the actual economics of gas transportation becomes one element of a much bigger scenario; with the extreme being that an oil development may not proceed if there is no means to dispose of the associated gas, thereby realising no value. An example is the Zafiro field discussed in the second chapter, where companies such as Conoco, BP and Statoil pulled out prior to the first well because it was thought to be too gas prone.

The Floating GTL plant can offer solutions to fields such as the Zafiro field and other gas prone oil reserves that have been left un-drilled, if deployed. Its use also extends to the non-associated stranded gas reserves in the 1 to 3 trillion cubic feet range, which have been considered non-viable for LNG application.

5.1.2 The EV Model

The EV model has been used to successfully carry out a quantitative economic appraisal on the viability of a Floating GTL plant based on two base case scenarios representing two available designs.

The main novel aspect of this model is that it combines four economic appraisal tools with the economy of scale in a single model. This unique feature makes it an entirely different modelling approach from the traditional 'maximum of two' economic appraisal tool model frequently used for economic analysis by different authors, mainly focusing on the NPV and IRR.

With this model the complex nature of decision making can now be simplified. This is due to the flexibility it exhibits. A single substitution of variables based on any scenario can now be used to generate a set of results for Internal Rate

of Return (IRR), Net Present Value (NPV), Profitability Index (PI), Discounted Payback Period (DPBP) and the Break-Even Point (BEP) at the same time using the economy of scale relationship as a basis for estimation.

The viability of 'pipelining to shore plus onshore GTL' option can also be determined using the EV model since the same economic parameters apply to both concepts. The results obtained can then be used to carry out trade studies on "pipeline to shore plus onshore GTL versus "Floating GTL".

For production capital projects like this, companies, governments and potential investors can now use my EV model in evaluating a Floating GTL investment decision by simply adjusting the variables to suite the specific investment scenario.

Finally, the EV model has successfully met the aim and objectives of this research work which was to determine the '*Economic Viability of a Floating GTL plant*'.

5.1.3 The way forward for offshore deployment of Floating GTL Plants

As the development programme progresses for Floating GTL plants, further significant cost reductions are envisaged due to process refinement and engineering definition that will make the technology fully competitive with regards to competing gas transportation alternatives. Due to its movable nature, the construction cost can also be reduced by taking the construction to shipyards with very low Construction Cost Indices.

The introduction of the Industrial Ceramic Membranes (ICM) for the generation of oxygen in future will eliminate the need for the Air separation

unit which accounts for over 30% of the overall capital cost of a typical GTL plant. The economic potential of this technology is significant. It will also reduce the footprint area necessary for a GTL plant making it very appropriate for offshore application. This will be especially useful for the existing Statoil's offshore Floating GTL design where the ASU and ATR are being used for Syngas generation.

Using preliminary assessment of the economies of natural gas via emerging technology application, there are limited opportunities to monetize offshore stranded natural gas reserves especially towards creation of non-traditional gas markets. However, given a rational cost gas feed, a supportive fiscal regime and high price crude oil, the application of offshore Floating GTL plants for stranded gas field starts to look economically viable.

In a recent development, Syntroleum has identified around 40 uncontracted prospective stranded gas reserves in Asia, the Middle East, West Africa and Latin America in the 1 to 3 trillion cubic feet range as initial targets for offshore Floating GTL plants representing an 8 Billion barrel opportunity (DeLuca 2005, Marcotte 2005).

This could be considered as a positive pointer for the deployment of GTL plants offshore. Results from the break-even analysis conducted in this study already shows that floating GTL plants can break-even for gas reserves as small as 0.6 trillion cubic feet. Successful deployment of these plants offshore will go a long way in encouraging other players in the industry to venture into the floating GTL business.

5.2 RECOMMENDATIONS

5.2.1 Government Policy

New dynamic evolution in the gas markets and gas technology development would probably influence the way the natural gas industry will develop in the nearest future. In the future, government should adjust its policy in natural gas utilization, especially for the development of stranded gas by opening new options through the application of emerging technologies such as the Floating GTL technology, enabling the creation of non-traditional gas markets.

This role of the government to assure direction of gas market transformation is essential. This can be done by establishing gas market and sector reforms through clear and transparent regulatory process, rational pricing framework, and introducing clear and innovative scheme providing special incentives such as fiscal and rational wellhead gas price to facilitate new investment for stranded natural gas development (Purwanto et. al., 2005:12).

5.2.2 Other Recommendations

Economy of scale should also be given careful consideration when planning an investment decision on a Floating GTL plant. The result of this study reveals an overwhelming fact that plant scale has a significant effect on the CAPEX both in terms of the capacity and return on the investment.

For a production capital project like this, investments decisions should not only be made by looking at the cash flows. A critical analysis of the entire decision and an assessment of all relevant variables and outcomes within a socio-economic hierarchy have to be done. The impact that such investments

has on the stakeholders and environment as a whole, should also be made a part of the decision making process.

This research work still has gray areas that have not been dealt with. Future research into this subject matter will probably investigate and discuss economy of scale in terms of the number of plants built or rolled out per unit time. Also, the reservoir management areas that could affect the feedstock cost could be investigated. There are also comparative studies that could be carried out with respect to other stranded gas monetisation options, using my work as a baseline or starting point.

In conclusion, this study has shown beyond reasonable doubt that deployment of Floating GTL plants offshore is possible, feasible and economically viable under certain conditions. Although, the technology is of paramount importance, other surrounding key factors/aspects identified were natural gas price and quality, capital cost, field size, competing gas users, product logistics, local infrastructure, fiscal regimes and safety.

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APPENDICES

7.1 Appendix 7.1: Global Gas Consumption and Flaring Distribution

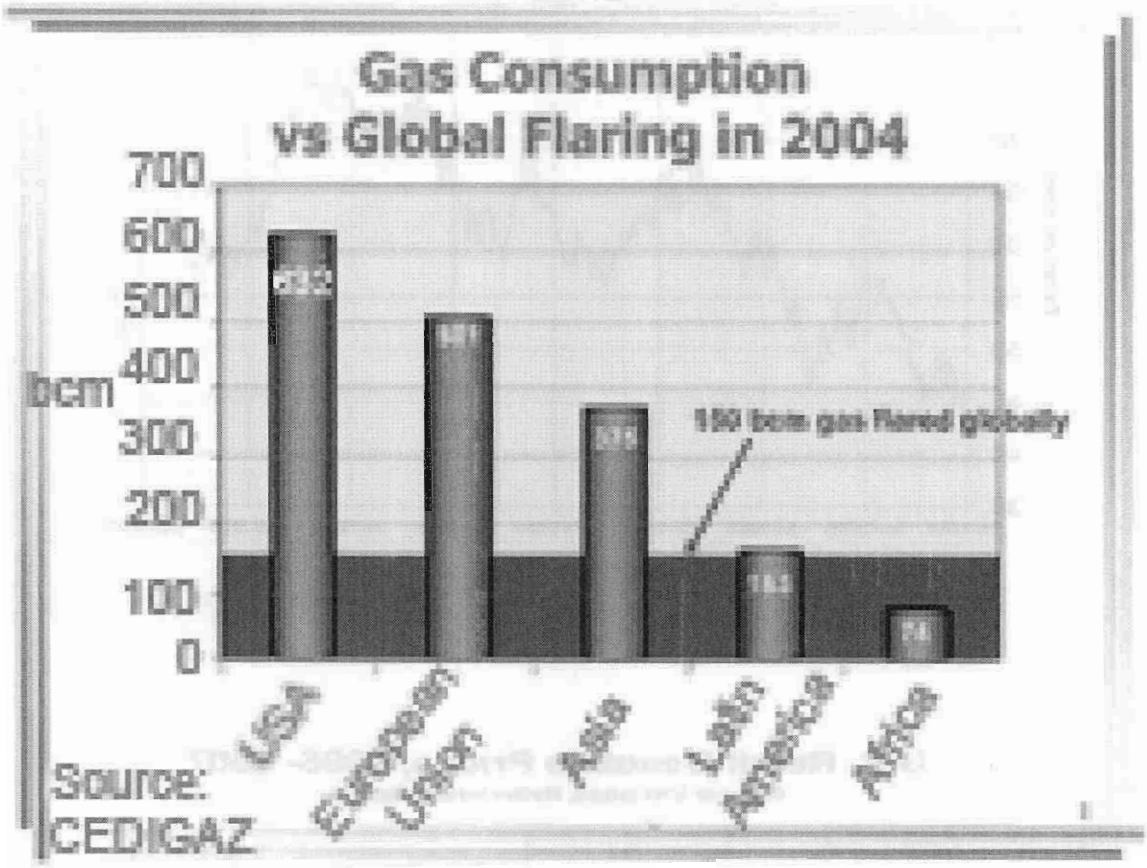

Chart: Global Gas Consumption vs. Global Gas Flaring

Source:
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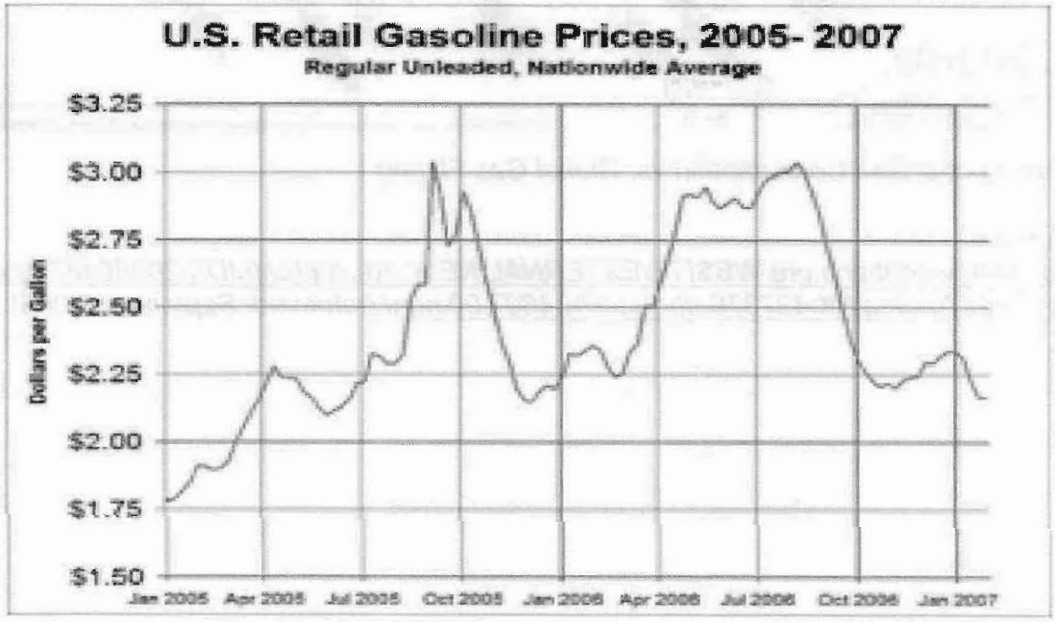
7.2 Appendix 7.2: Gasoline and Crude Oil Prices



Source: http://en.wikipedia.org/wiki/the_price_of_oil_and_the_economy

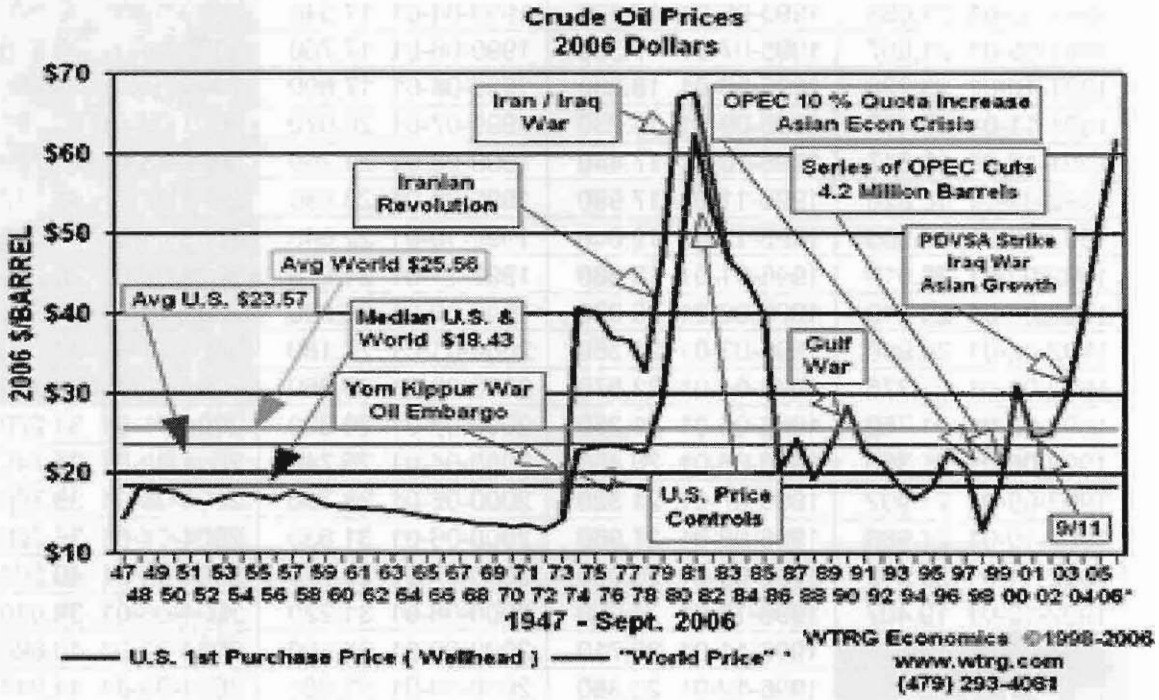
Retrieved: December, 2006

7.2.1 Appendix 7.2A: Monthly Crude Oil Prices ($/Bbl) from 1991 – 2006

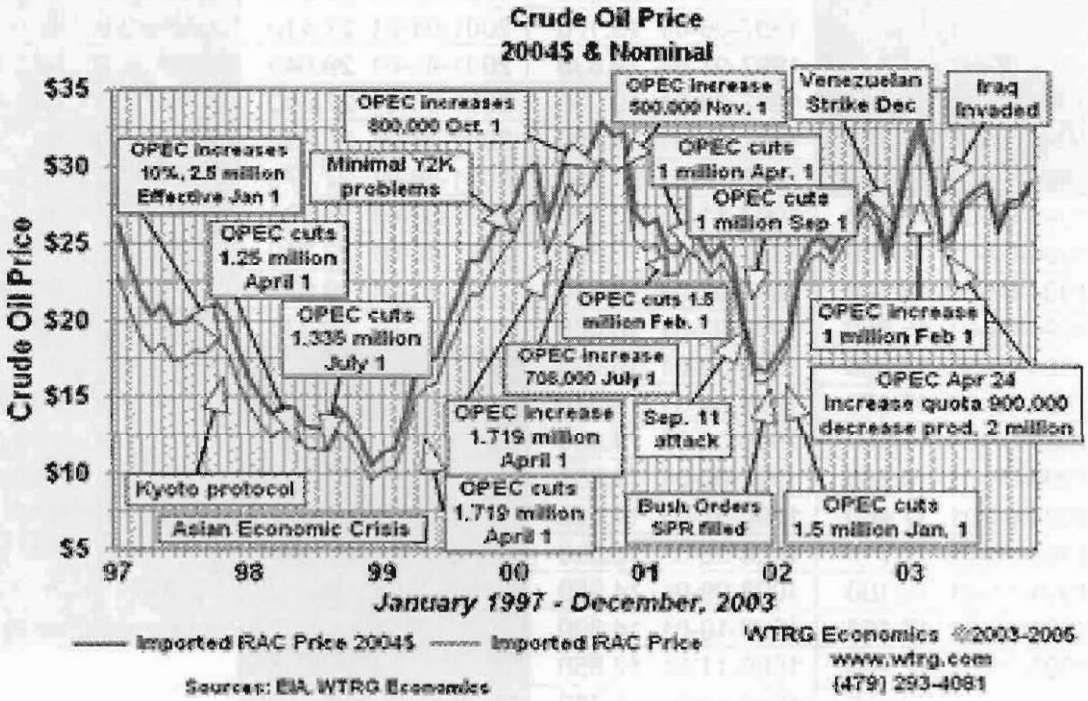
1991-08-01	21.688	1995-06-01	18.420	1999-04-01	17.340	2003-02-01	35.870
1991-09-01	21.857	1995-07-01	17.300	1999-05-01	17.750	2003-03-01	33.550
1991-10-01	23.228	1995-08-01	18.030	1999-06-01	17.890	2003-04-01	28.250
1991-11-01	22.465	1995-09-01	18.230	1999-07-01	20.070	2003-05-01	28.140
1991-12-01	19.517	1995-10-01	17.440	1999-08-01	21.260	2003-06-01	30.720
1992-01-01	18.820	1995-11-01	17.990	1999-09-01	23.880	2003-07-01	30.760
1992-02-01	18.995	1995-12-01	19.040	1999-10-01	22.640	2003-08-01	31.590
1992-03-01	18.916	1996-01-01	18.880	1999-11-01	24.970	2003-09-01	28.290
1992-04-01	20.243	1996-02-01	19.070	1999-12-01	26.080	2003-10-01	30.330
1992-05-01	20.940	1996-03-01	21.360	2000-01-01	27.180	2003-11-01	31.090
1992-06-01	22.375	1996-04-01	23.570	2000-02-01	29.350	2003-12-01	32.150
1992-07-01	21.759	1996-05-01	21.250	2000-03-01	29.890	2004-01-01	34.270
1992-08-01	21.350	1996-06-01	20.450	2000-04-01	25.740	2004-02-01	34.740
1992-09-01	21.902	1996-07-01	21.320	2000-05-01	28.780	2004-03-01	36.760
1992-10-01	21.688	1996-08-01	21.960	2000-06-01	31.830	2004-04-01	36.690
1992-11-01	20.342	1996-09-01	23.990	2000-07-01	29.770	2004-05-01	40.280
1992-12-01	19.407	1996-10-01	24.900	2000-08-01	31.220	2004-06-01	38.020
1993-01-01	19.075	1996-11-01	23.710	2000-09-01	33.880	2004-07-01	40.690
1993-02-01	20.053	1996-12-01	25.390	2000-10-01	33.080	2004-08-01	44.940
1993-03-01	20.347	1997-01-01	25.170	2000-11-01	34.400	2004-09-01	45.950
1993-04-01	20.270	1997-02-01	22.210	2000-12-01	28.460	2004-10-01	53.130
1993-05-01	19.940	1997-03-01	20.990	2001-01-01	29.580	2004-11-01	48.460
1993-06-01	19.070	1997-04-01	19.720	2001-02-01	29.610	2004-12-01	43.330
1993-07-01	17.866	1997-05-01	20.830	2001-03-01	27.240	2005-01-01	46.840
1993-08-01	18.009	1997-06-01	19.170	2001-04-01	27.410	2005-02-01	47.970
1993-09-01	17.514	1997-07-01	19.630	2001-05-01	28.640	2005-03-01	54.310
1993-10-01	18.145	1997-08-01	19.930	2001-06-01	27.600	2005-04-01	53.040
1993-11-01	16.699	1997-09-01	19.790	2001-07-01	26.450	2005-05-01	49.830
1993-12-01	14.510	1997-10-01	21.260	2001-08-01	27.470	2005-06-01	56.260
1994-01-01	15.000	1997-11-01	20.170	2001-09-01	25.880	2005-07-01	58.700
1994-02-01	14.780	1997-12-01	18.320	2001-10-01	22.210	2005-08-01	64.970
1994-03-01	14.660	1998-01-01	16.710	2001-11-01	19.670	2005-09-01	65.570
1994-04-01	16.380	1998-02-01	16.060	2001-12-01	19.330	2005-10-01	62.370
1994-05-01	17.880	1998-03-01	15.020	2002-01-01	19.670	2005-11-01	58.300
1994-06-01	19.070	1998-04-01	15.440	2002-02-01	20.740	2005-12-01	59.430
1994-07-01	19.650	1998-05-01	14.860	2002-03-01	24.420	2006-01-01	65.510
1994-08-01	18.380	1998-06-01	13.660	2002-04-01	26.270	2006-02-01	61.630
1994-09-01	17.460	1998-07-01	14.080	2002-05-01	27.020	2006-03-01	62.900
1994-10-01	17.710	1998-08-01	13.360	2002-06-01	25.520	2006-04-01	69.690
1994-11-01	18.100	1998-09-01	14.950	2002-07-01	26.940	2006-05-01	70.940
1994-12-01	17.160	1998-10-01	14.390	2002-08-01	28.380	2006-06-01	70.960
1995-01-01	17.990	1998-11-01	12.850	2002-09-01	29.670		
1995-02-01	18.530	1998-12-01	11.280	2002-10-01	28.850		
1995-03-01	18.550	1999-01-01	12.470	2002-11-01	26.270		
1995-04-01	19.870	1999-02-01	12.010	2002-12-01	29.420		
1995-05-01	19.740	1999-03-01	14.660	2003-01-01	32.940		

Source: Dow Jones & Company: http://www.forecast.org/index.htm

7.3 Appendix 7.3: World Events and Crude Oil Prices from 1947 to 2006



World Events and Crude oil prices from 1997 to 2003



Source: www.wtrg.com/oil_graphs (Retrieved: January, 2007)

7.4 Appendix 4: TABLES OF EV MODEL SIMULATION RESULTS

BASE CASE SCENARIO ONE

BASE CASE ONE					
PC (MBPD)	CAPEX (M$/BPD)	NPV1 (MM$)	NPV2 (MM$)	NPV 3 (MM$)	NPV 4 (MM$)
10	26	443	216	100	35.2
20	20	974	515	276	141
30	17	1,530	834	472	266
40	15	2,100	1,170	680	402
50	14	2,660	1,490	882	532
70	12	3,820	2,190	1,330	828
100	11	5,530	3,190	1,960	1,240

Table 7.1: NPVs for varying Plant Capacities and CAPEXs

BASE CASE ONE					
PC (MBPD)	CAPEX (M$/BPD)	PI1	PI2	PI3	PI4
10	26	2.70	1.83	1.38	1.14
20	20	3.44	2.29	1.69	1.35
30	17	4.00	2.64	1.92	1.52
40	15	4.49	2.94	2.13	1.67
50	14	4.79	3.13	2.26	1.76
70	12	5.55	3.60	2.58	1.99
100	11	6.03	3.90	2.78	2.13

Table 7.2: PI values for varying Plant Capacities and CAPEXs

BASE CASE ONE			
PC (MBPD)	CAPEX (M$/BPD)	IRR	DPBP @15% DR(YRS)
10	26	0.30	4.38
20	20	0.36	3.13
30	17	0.41	2.58
40	15	0.46	2.23
50	14	0.48	2.05
70	12	0.54	1.74
100	11	0.57	1.58

Table 7.3: IRR and DPBP for varying Plant Capacities and CAPEXs

BASE CASE SCENARIO TWO

BASE CASE TWO					
PC (MBPD)	CAPEX (M$/BPD)	NPV1 (MM$)	NPV2 (MM$)	NPV 3 (MM$)	NPV 4 (MM$)
10	51	260	43.8	-60.5	-113
14.5	44	451	134	-22.7	-104
30	33	1,180	503	164	-19.1
40	29	1,690	781	322	69.5
50	27	2,180	1,050	466	146
70	23	3,260	1,660	832	371
100	20	4,870	2,570	1,380	708

Table 7.4: NPVs for varying Plant Capacities and CAPEXs

BASE CASE TWO					
PC (MBPD)	CAPEX (M$/BPD)	PI1	PI2	PI3	PI4
10	51	2.70	1.83	1.38	1.14
14.5	44	3.44	2.29	1.69	1.35
30	33	4.00	2.64	1.92	1.52
40	29	4.49	2.94	2.13	1.67
50	27	4.79	3.13	2.26	1.76
70	23	5.55	3.60	2.58	1.99
100	20	6.03	3.90	2.78	2.13

Table 7.5: PIs for varying Plant Capacities and CAPEXs

BASE CASE TWO (STATOIL)			
PC (MBPD)	CAPEX (M$/BPD)	IRR	DPBP @15% DR(YRS)
10	51	0.17	14.58
14.5	44	0.19	10.08
30	33	0.24	6.11
40	29	0.27	5.06
50	27	0.29	4.60
70	23	0.33	3.73
100	20	0.36	3.13

Table 7.6: IRR and DPBP for varying Plant Capacities and CAPEXs

SENSITIVITY ANALYSIS RESULTS

FEEDSTOCK COST (FC): SENSITIVITY ANALYSIS (NPV @ 15% DR)				
FC ($/Bbl)	NPV_BC1A (million$)	NPV_BC2A (million$)	NPV_BC1B (million$)	NPV_BC2B (million$)
0	720	282	2,910	2,380
5	617	208	2,550	2,020
10	515	133	2,190	1,660
20	309	-15.3	1,470	938
30	104	-164	750	220
40	-101	-313	32.1	-498

Table 7.7: NPV sensitivity to variations in Feedstock Cost

FEEDSTOCK COST (FC): SENSITIVITY ANALYSIS (IRR)				
FC ($/Bbl)	IRR_BC1A	IRR_BC2A	IRR_BC1B	IRR_BC2B
0	0.44	0.23	0.64	0.39
5	0.40	0.21	0.59	0.36
10	0.36	0.19	0.54	0.33
20	0.29	0.15	0.43	0.26
30	0.20	0.09	0.31	0.18
40	0.10	0.03	0.16	0.08

Table 7.8: IRR sensitivity to variations in Feedstock cost

OPERATING COST (OC): SENSITIVITY ANALYSIS (NPV @ 15% DR)				
OC ($/Bbl)	NPV_BC1A (MM$)	NPV_BC2A (MM$)	NPV_BC1B (MM$)	NPV_BC2B (MM$)
5	545	156	3,990	1,760
10	443	81.4	1,940	1,410
15	340	6.99	1,570	1,050
20	238	-67.4	1,220	687
30	32.1	-216	499	-31.3
40	-173	-365	-219	-750

Table 7.9: NPV sensitivity to variations in Plant Operating Cost

OPERATING COST (OC): SENSITIVITY ANALYSIS (IRR)				
OC ($/Bbl)	IRR_BC1A	IRR_BC2A	IRR_BC1B	IRR_BC2B
5	0.38	0.20	0.55	0.34
10	0.34	0.17	0.50	0.30
15	0.30	0.15	0.45	0.27
20	0.26	0.13	0.39	0.23
30	0.17	0.07	0.26	0.15
40	0.05	0.00	0.09	0.04

Table 7.10: IRR sensitivity to variations in Plant Operating Cost

PRODUCT PRICE (PP): SENSITIVITY ANALYSIS (NPV @ 15% DR)				
PP ($/Bbl)	NPV_BC1A (MM$)	NPV_BC2A (MM$)	NPV_BC1B (MM$)	NPV_BC2B (MM$)
20	-204	-387	-327	-857
30	1.59	-239	391	-139
40	207	-89.7	1,110	579
50	412	59.1	1,830	1,300
60	617	208	2,550	2,020
70	822	357	3,260	2,730

Table 7.11: NPV sensitivity to variations in Product Price

PRODUCT PRICE (PP): SENSITIVITY ANALYSIS (IRR)				
PP ($/Bbl)	IRR_BC1A	IRR_BC2A	IRR_BC1B	IRR_BC2B
20	0.02		0.06	0.01
30	0.15	0.06	0.24	0.13
40	0.24	0.12	0.37	0.22
50	0.33	0.17	0.49	0.29
60	0.40	0.21	0.59	0.36
70	0.47	0.25	0.68	0.42

Table 7.12: IRR sensitivity to variations in Product Price

7.5 Appendix 7.5: Conversion Rates

Energy

Unit	Equivalent to
Gigajoule (GJ)	10^9 joules 0.95 million Btu 0.95 thousand cubic feet of natural gas at 1000 Btu/cf 0.165 barrels of oil 0.28 megawatt hour of electricity

Table 7.13: Energy Conversion rates/factors

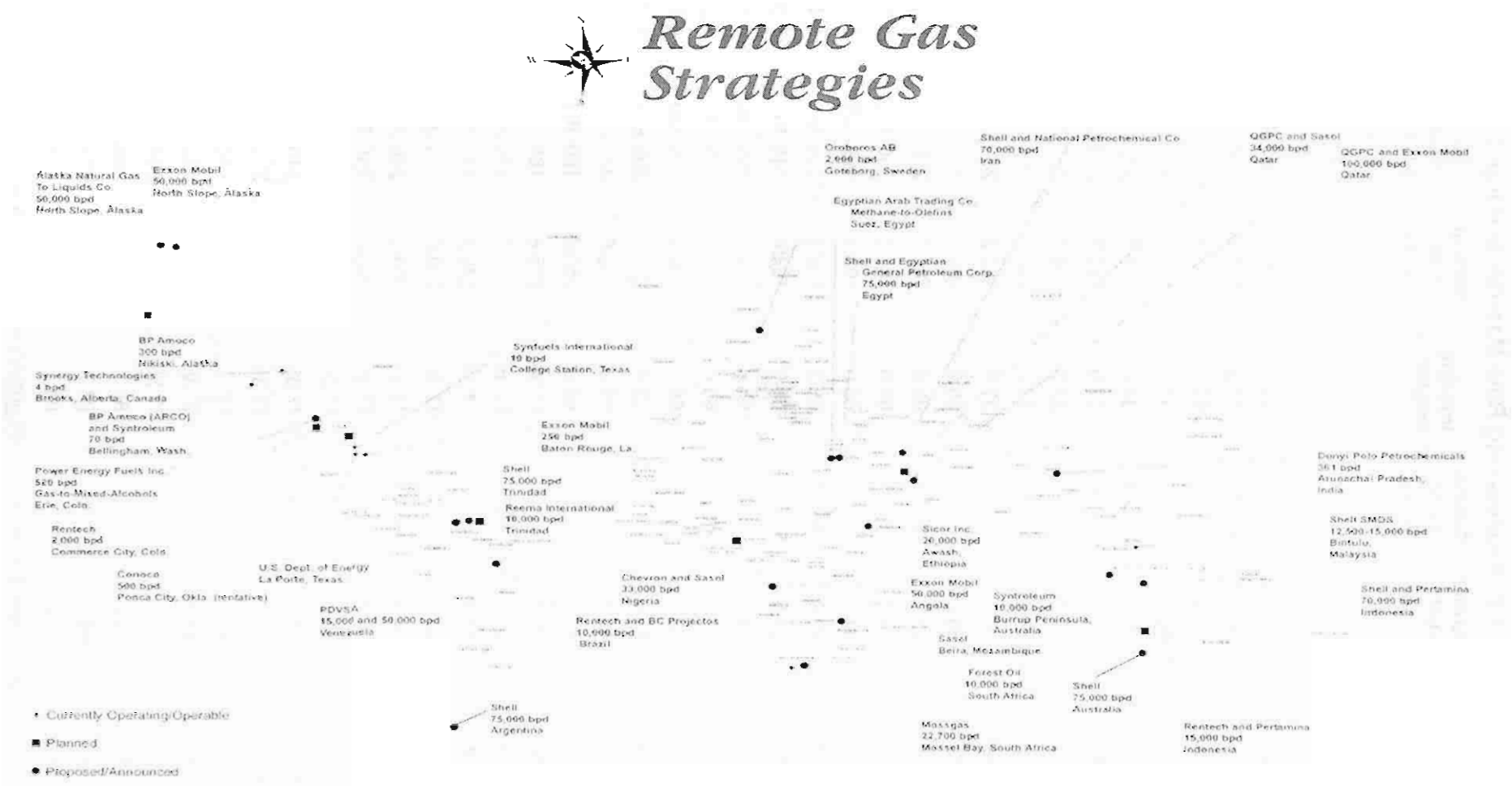
Natural Gas

Unit	Equivalent to
1 cubic metre (m^3)	35.301 cubic feet @ 14.73 psia and 60°F
Thousand cubic feet (MCF)	1.05 GJ
Million cubic feet (MMCF)	1.05 TJ
billion cubic feet (BCF)	1.05 PJ
trillion cubic feet (TCF)	1.05 EJ

Table 7.14: Natural gas conversion factors/rates

Source: http://www.neb-one.gc.ca/Statistics/EnergyConversions_e.htm
Retrieved: August, 2006

7.6 Appendix 7.6: Global Distribution of Proposed and Existing GTL Plants



Source: www.Ingexpress.com

7.7 Appendix 7.7: Steelmaking Raw Material and Input Costs

Year/ Month	Thermal Coal $/tonne	Coking Coal $/ton	Iron Ore Cents/dmtu	Natural Gas $/1000m3	Steel Scrap $/tonne	Electricity Cents/KwH
2004 M1	40.4		37.9	122.0	225-230	5.01
2004 M2	44.7	53.81	37.9	122.0	255-260	5.04
2004 M3	52.4		37.9	122.0	220-225	5.04
2004 M4	57.1		37.9	125.3	200-205	5.09
2004 M5	60.5	59.46	37.9	125.3	150-160	5.18
2004 M6	63.8		37.9	125.3	170-175	5.46
2004 M7	65.8		37.9	137.2	225-235	5.63
2004 M8	63.5	64.18	37.9	137.2	240-250	5.65
2004 M9	59.3		37.9	137.2	220-225	5.41
2004 M10	60.7		37.9	156.2	235-240	5.25
2004 M11	56.6	68.87	37.9	156.2	250-265	5.09
2004 M12	56.0		37.9	156.2	200-210	5.14
2005 M1	56.8		65.0	182.2	200-210	5.23
2005 M2	53.5	82.67	65.0	182.2	200-205	5.26
2005 M3	54.6		65.0	182.2	200-205	5.30
2005 M4	54.9		65.0	198.4	195-205	5.31
2005 M5	55.0	84.71	65.0	198.4	155-165	5.42
2005 M6	54.6		65.0	198.4	145-150	5.86
2005 M7	54.5		65.0	220.7	195-200	6.14
2005 M8	52.6	85.68	65.0	220.7	225-235	6.20
2005 M9	48.5		65.0	220.7	235-240	6.17
2005 M10	45.5		65.0	250.6	205-210	6.03
2005 M11	40.8	83.24	65.0	250.6	200-205	5.83
2005 M12	41.0		65.0	250.6	180-190	5.94
2006 M1	46.3		77.35	275.8	185-190	5.79
2006 M2	51.1	90.22	77.35	275.8	215-220	5.87
2006 M3	53.3		77.35	275.8	210-215	5.82
2006 M4	56.7		77.35	293.0	220-225	5.85
2006 M5	56.4	94.23	77.35	293.0	240-250	5.91
2006 M6	56.1		77.35	293.0	255-260	6.35
2006 M7	56.5		77.35	302.4	250-255	6.50
2006 M8	54.6	94.83	77.35	302.4	245-250	6.56
2006 M9	50.5		77.35	302.4	230-235	6.27
2006 M10	47.2		77.35	311.4	230-245	6.12
2006 M11	49.3	n/a	77.35	311.4	230-245	5.97
2006 M12	53.3		77.35	311.4	245-250	5.96
2007 M1	55.0		84.7	302.0	264-270	n/a
2007 M2	56.7	n/a	84.7	302.0	275-280	n/a
2007 M3	n/a		84.7	302.0	n/a	n/a

Source: http://www.steelonthenet.com/commodity_prices.html

7.7.1 Appendix 7.7A: World Carbon Steel Transaction Prices

World Steel Prices US $/tonne	Hot Rolled Steel Coil	Hot Rolled Steel Plate	Cold Rolled Steel Coil	Steel Wire Rod	Medium Steel Sections
Jan 2006	510	649	613	446	602
Feb 2006	503	646	607	447	602
Mar 2006	516	651	620	462	612
Apr 2006	538	670	636	480	631
May 2006	569	717	668	495	666
Jun 2006	599	741	703	513	685
Jul 2006	597	736	702	517	703
Aug 2006	599	737	704	519	705
Sep 2006	591	755	691	521	716
Oct 2006	569	740	664	507	701
Nov 2006	560	743	658	501	718
Dec 2006	558	757	665	499	734
Jan 2007	549	747	647	495	735

All steel prices are in $/metric tonne. *Steel price information updated April 2007. Source: MEPS Steel Prices On-line. To obtain current steel prices including forecasts, please visit http://www.meps.co.uk/world-price.htm. (Retrieved on April 12 2007)*

7.8 Appendix 7.8 General Information

The data used for the validation of this research work and all other information regarding the Meren 1 field cannot be referenced due to certain conditions relating to the use of the field information.