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OPTIMISING LIQUEFIED NATURAL GAS SUPPLY CHAINS
-A case study in China

By

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China

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Declaration

I certify that all the material in this dissertation that is not my own work has been identified, and that no material is included for which a degree has previously been conferred on me.

The contents of this dissertation reflect my own personal views, and are not necessarily endorsed by the University.

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Abstract

Title of Dissertation: **Optimising liquefied natural gas supply chains – A case study in China**

Degree: **MSc**

The dissertation is a study of optimising liquefied natural gas (LNG) supply chains based on total cost analysis. One case study in China is completed to demonstrate the optimisation procedures and applications.

A brief look is taken at worldwide gas market, and at gas gaps in China. Imports strategies and LNG projects in China are investigated. In launching the LNG projects, the key issues are to optimise LNG chains including selection of gas resources, capacities of LNG carrier and re-gasification terminal facilities.

The definition, technical and economical features of the LNG chain are identified. FOB supply costs are investigated. More deep analyses and estimations are completed in the total cost structure, shipping costs and re-gasification costs.

As to the case study, Guangdong LNG project in China is selected and total costs analysis is introduced based on the investigations of previous studies in this area. Optimising is completed after costs calculations and the optimal LNG chains are suggested.

The estimations in this study were collated and evaluated comparing with the latest official decisions on this project and related research results.

The concluding chapters review main findings in this study and address the optimal LNG supply chains in the case study. They also identify the limitations of this research. Finally a number of recommendations and a mathematic model are suggested for further research.

Keywords: LNG, optimising, total costs, supply chain, LNG chain, China

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List of abbreviations

Bcf	Billion cubic feet
Bcm	Billion cubic meters
BTU	British thermal unit
CERA	Cambridge energy research associates
CIF	Cost, insurance and freight rate
CNG	Compressed natural gas
CNOOC	China national offshore oil corporation
CNPC	China national petroleum corporation
CO_2	Carbon dioxide
EIA	Energy information administration, U.S.A
FOB	Free on board
FPSO	Floating Production Storage and Offloading
FSRU	Floating storage and re-gasification unit
GTL	Gas-to-Liquids
HKSAR	Hong Kong special administrative region
IEA	International energy agency
LNG	Liquefied natural gas
LNGC	LNG carrier
LPG	Liquefied petroleum gas
MMBtu	Million British thermal unit
Mtpa	Million tons per annum
NG	Natural gas
NGH	Natural gas hydrate
ORV	Open rack vaporizer
PetroChina	PetroChina company limited

PRD	Pearl River Delta
SCV	Submerged combustion vaporizer
SDPC	State development planning commission, China
SETC	State economic and trade commission, China
SPA	Sales and purchase aggreement
TCE rates	Time charter equivalent rates
Tcf	Trillion cubic feet
Tcm	Tillion cubic meters

Introduction

1. Statement of purpose

Natural gas consumption will increase in the coming years in China as a clear energy. Currently natural gas is not used as a main source in the primary energy. However, the demands for natural gas are driven to increase significantly by some forces: energy security, environmental concerns and diversification of energy (Rand, 2001). Gas gaps will exist in China even more new gas fields were found and many projects were launched to exploit and develop natural gas. There will be a gas gap between demand and supply (Xiaojie, 1999). Therefore, gas imports are becoming key issues to support national energy policy and meet roaring demands for natural gas.

There are two key delivery options to import natural gas: by pipeline or in the form of liquefied natural gas (LNG). There is heavy investment in a natural gas imports project because far distances exist between gas resources and end-users, huge capital costs in infrastructures needs for both pipeline and LNG. Moreover, the selection between pipeline and LNG depends on their economic features to a specific project. Many researchers believed that LNG had more competitive advantages when the distance becomes longer. In addition to pipeline and LNG, some new technologies have been developed (Gudmundsson, 2001).

Optimising LNG supply chains is a key issue to a successful gas imports project. To a specific gas imports project, many options exits from gas resources to gas transport. For example, China can import natural gas from the Middle East, South East Asia or the Former Soviet Union (FSU), and these gas maybe transported by pipeline or sea transport (Rand, 2000). The selection depends on their economic features, but is also heavily influenced by political and other factors. In order to ensure success economic appraisals are necessary. Moreover, the appraisals should be conducted to the whole gas value chain broadly so as to find the optimal solution. However, the comparison and selection between pipeline and LNG transport exceeds this research; the aim of this research is to evaluate and optimising a supply chain of a specific LNG imports project.

This dissertation aims at optimising an LNG supply chain combining a case study based on total cost analysis (Douglas, 1998, p469). Some LNG projects in China have been launched and discussed, for example, the first LNG imports project in China will operate in 2005 and the selection of an LNG chain is in process (see Appendix F). The aim of this research is to set "total costs" (Douglas, 1998, p15) as criteria of appraisal and to analysis and evaluate economic features of the LNG supply chain, then to seek the best solution for the project. In this study one case as Guangdong LNG project is introduced so that this research becomes more reality. Moreover, this approach of economic analysis provides one general method which can be used to evaluate any LNG imports project.

2. Research procedure

This research is based on literature reviews, data collection and calculation approaches etc. The literature reviews focused on relevant economic theories, natural gas market, technical and economic features of an LNG chain, relationships between sections of the LNG chain and approach of appraisals. Data collection concentrated on natural gas imports in China, cost structure of an LNG supply chain, Free-on-board (FOB) supplying costs, shipping costs and terminal costs. Calculation approaches are included in financial appraisal approaches, optimising mathematic models and assumptions to an economic analysis.

2.1 Literature review

The literature review is an essential work for a research paper. The aims of literature reviews are to gather related works that have been written on the energy and LNG industry in the world and in China, to get awareness of current scenarios on the LNG industry, to understand limitations of what have been done on this subject, and to identify the objectives and approaches of the proposed research.

Literature reviews in this dissertation include review literature on economic and logistic theories, natural gas market, technical and economic features of an LNG chain, relationships between sections of the LNG chain and approach of appraisals. The resources on economic and logistic theories and approach of appraisals are mainly books, handouts, consulting reports and dissertations from libraries, courses and electronic publications on the web sites. The resources about technical and economic features of an LNG chain, gas market in the world and China are partly from books in World Maritime University (WMU) library, and are mainly from the reports published by Cambridge Energy Research Associate (CERA), Energy Information Administration (EIA), the proceedings issued by LNG gas conferences, as well as electronic publications on the websites. These were found with the help of Mr. Yeteghen and Mrs. Yan Li.

2.2 Collection of data

Collection of data is the key issue for estimate and evaluation. Data collection concentrated on natural gas imports in China, cost structure of an LNG supply chain, FOB supplying costs, shipping costs and terminal costs. The sources are statistical books issued by Chinese government and BP company, relevant research results about the LNG industry, conference reports on LNG in the world and China, consulting reports and articles from magazines, journals and web sites.

2.3 Calculation approach

Calculation approaches concentrated on financial appraisal approaches, optimising mathematical models and assumptions to an economic analysis. The main approach is based on present value analysis and calculations are based on spreadsheet (Excel developed by Microsoft, Ltd). The sources are books, handouts and consulting reports from libraries and courses at WMU. The approach was selected with the help of Mr. Yatagehen of GTT. Further, the mathematical modal was created with the help of professor Imai.

3. Organisation of the dissertation

The dissertation consists of five chapters, in addition to the introduction and conclusion. Chapter 1 concentrates on LNG imports in China. This begins with a description of current international gas trade and transport, further, discusses gas gaps in China. The following section of this chapter identifies imports strategies and LNG projects in China.

Chapter 2 identifies technical and economic features of an LNG chain, in addition to FOB supply costs. The first section defines concept and elements of the LNG chain; then commercial and business features of LNG chain are addressed; the following sections discusses cost structures of an LNG chain and shows FOB supply costs of some gas supplier states based on CERA research.

Chapter 3 discusses LNG shipping. This begins with description of LNG carriers (LNGC). The second section identifies cost structure of shipping costs and estimate typical shipping costs, then development in technology and markets of LNG shipping are discussed.

Chapter 4 focused on LNG receiving terminal and re-gasification facilities. The first section presents key issues in feasible study and risky analysis in the planning LNG receiving terminals, then technical features of receiving facilities are identified, the following section discussed cost structure of re-gasification costs.

Chapter 5 completed calculations and optimising LNG chains in a case study in China. In the first part optimising procedures and background of the case is introduced. The second part completes the calculation of total costs of LNG supply chains, the main results are listed in the third section. Then the results are analysed and the optimal LNG chains are recommended.

Finally in the section of conclusions and recommendations, the main conclusions of the research are summarised and limitations of this study are identified. The recommendations are suggested for the further study.

Chapter 1 Natural gas imports and LNG projects in China

Introduction

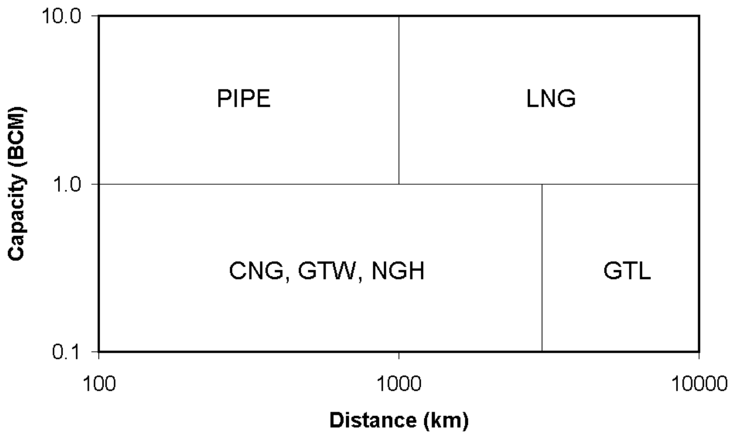
World natural gas reserves reached 1,235 trillion cubic feet and 77% was held by top 10 states in 2001 (EIA, 2002). The natural gas consumption worldwide accounted for 25 percent of the whole energy consumption in 2000, and it is projected to almost double between 1999 and 2020, growing from 84 trillion cubic feet to 162 trillion cubic feet (EIA, 2002). This is due to a number of factors, including price, environmental concerns, fuel diversification and/or energy security issues, deregulation of both natural gas and electricity markets and overall economic growth. China is the world's most populous county and the second largest energy consumer after the United States. Natural gas currently accounts for only slightly more than 3% of total energy consumption in China but is expected to more than triple by 2010. This will involve increases in domestic production and imports by pipeline and in the form of LNG.

In this chapter international natural gas trade and transport are briefly described, further, natural gas in China are identified, gas imports strategies and the major LNG projects are presented.

1.1 International natural gas trade and transport

With many natural gas resources located far from demand centers, no global gas market emerged and only three regional natural gas markets exist in Asia, Europe and U.S.A. In 2000, it is only about 23% of the natural gas consumed worldwide that was traded across international boards, 22 percent of that in the form of liquefied natural gas (LNG) and the others through pipelines (BP, 2002).

The expensive transport costs have been the main constrains since international natural gas trades were set up. Besides pipeline and LNG, the other non-pipeline technologies for gas transport have been developed to bring natural gas to the new markets, which include natural gas hydrate (NGH), compressed natural gas (CNG), gas-to-liquids (GTL) and gas-to-wire (GTW). The details about these technologies and their competitive advantages refer to Appendix B-1. Figure 1.1 shows the selection of these technologies to meet different gas demand and distance.



Source: Gudmundsson

Figure 1.1 Capacity-distance diagram of natural gas transport

With many natural gas resources located far from demand centers, LNG will become progressively more attractive as a method of transport.

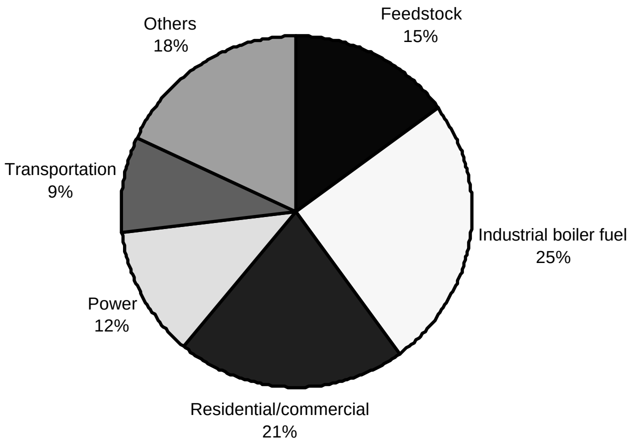
1.2 Natural gas imports in China

Historically, natural gas has not been a major fuel in China, currently gas accounts for only slightly more than 3% of total energy consumption in China. However, environmental concerns and energy diversification in China are prompting movement toward gas and away from coal and oil, the gas consumption is expected to more than triple by 2010 (Rand, 2000).

1.2.1 Natural gas demand in China

In 2001, China consumed approximately 30.2 billion cubic meters natural gas, including Hong Kong (BP, 2002). Most of it concentrated in four sectors (Figure 1.2):

- Chemical feedstock
- Industrial boiler fuel
- Residential/commercial
- Power generation



Source: Cambridge energy research associates (CERA)

Figure 1.2 Gas consumption in China in 2000

In term of the consumption regions, three coastal regions in particular to drive growth in gas consumption: the Guangdong coast, the Yangtze Delta, and Bohai Bay rim (CERA, 2002). More details about the energy consumptions in these regions see Appendix F.

Natural gas consumption in China is projected to increase by 6 percent per year from 1999 to 2020, raising the natural gas share of China's energy consumption to 9 percent by 2020 (EIA, 2002). **At least 67 Bcm in 2010 and 104 Bcm natural gas per year by 2020 will be demanded for consumption** (Table 1.1).

Table 1.1 Natural gas outlooks in China

Year		2001	2010		2020	
Scenarios		Actual	High	Low	High	low
Amount of natural gas (Bcm per year)	Demand	27.3	85.8	67.2	170.5	104.4
	Supply	30.3	65.0		105.5	
	Gas gaps	**-**	**20.8**	**2.2**	**65.0**	**1.1**

Source: BP, CERA

1.2.2 Gas supply and gas gaps

Total natural gas production in China in 2001 was 30.3 billion cubic meters (Bcm). CERA (2002) estimates that China's potential gas productive capacity may be as high as **65 Bcm per year in 2010 and 105.5 Bcm per year by 2020.** Therefore, **gas gap can be 20.8 Bcm in 2010 and 65.0 Bcm per year by 2020.**

1.2.3 Gas Import Patterns

Gas imports will increase to meet gas gap in the future. it is necessary to import gas in order to improve reach China's primary energy structure and aim to account for about 8 percent and 9 percent out of demand primary energy mix in 2010 and in the period of 2015-2020 (Xu,1997)**.** China has a two-pronged import gas strategy:

(1) ***Inland markets can be linked with domestic and international natural gas supplies by pipelines;***

(2) ***Southeastern coastal regional demand can meet growing energy needs by switching to LNG shipment by sea-lanes***.

1.3 LNG projects in China

Currently, gas supply to Shanghai from the Pinghu offshore gas field is US$5.00 per MMBtu delivered. The supply to Hainan from Yacheng-13 offshore gas is US$4.00 per MMBtu to US$4.45 per MMBtu. According to the research of CERA (2002), **the cost of LNG ex-regasification plant must be approximately US$3.50 per MMBtu in the initial southern markets in China.**

Imported LNG will be used primarily in China's southeastern coastal region. Now three LNG receiving terminals and landing delivery systems in China are in the process of planning, where on its coastal line on Yangtz Delta, Zhujiang Delta and E.S. Fujiang Triangle. Imports volume through these terminals can be ***equal to 3-5million tons in 2010 and rise to about 9-19 Mt (equal to 27.6-34.5 bcm) per year by 2020*** (CERA, 2002). These projects include:

1.3.1 Guangdong LNG project

In this project a "trial" terminal and re-gasification facility with capacity of 3 million tons per year (MTPA) will be built in Shenzhen, on China's dynamic Guangdong coast. Expansion would ultimately bring imports capacity to 6.0 MTPA by 2010. Expansion of the project through Phase II will depend on the smooth implementation of Phase I. More details refer to Appendix F.

1.3.2 Fujian LNG project

Another LNG import terminal is planned in Fujian province and the planning can be completed in 2005 or 2006. In addition to the Guangdong facility, CNOOC signed an agreement with the Fujian provincial government to build a 2 million metric ton LNG receiving terminal. CNOOC would take responsibility for the terminal and an attached trunk pipeline, and the Fujian government would take care of the provincial distribution network. A detailed study must be done and submitted to the State Development Planning Commission for approval, but CNOOC would like to begin operation by 2005 or 2006. Fujian province is located on the south China coast between the LNG facility planned for Guangdong and the West-East pipeline that is intended to extend to Shanghai.

1.3.3 Yangtze Delta

Depending on the performance of the Shenzhen facility, another 3.0 MTPA terminal would be built in Jiangsu or Zhejiang province in Southeast China to serve the Shanghai market, probably post-2010. The timing of this phase is uncertain given competition between several projects; Shanghai is the terminus for one existing subsea pipeline, one planned onshore line (the West-to-East project), and the proposed LNG terminal. The significant potential of the Shanghai market—perhaps 20 Bcm per year by 2010—indicates that multiple sources of supply are supportable. Nonetheless, West-to-East supplies will be “chosen” first and the LNG terminal will be delayed from current plans by several years.

Summary

In this chapter international natural gas trade and transport are described. Besides pipeline and LNG, more new technologies have been introduced to transport natural gas to new markets. Certainly transport distance and volume have impacts on selection on these technologies. Moreover, LNG trade will increase in coming years. Natural gas has not been a major fuel in China, but its consumption is expected to more than triple by 2010 and reach to 9 percent in the whole primary energy consumption because of environment concern, energy diversification. Three coastal regions in particular to drive growth in gas consumption: the Guangdong coast, the Yangtze Delta, and Bohai Bay rim.

Gas gaps will exist and are expected to be about 20 Bcm per year in 2010 and 65 Bcm per year by 2020. It is necessary to import gas by pipeline or in form of LNG. The imports strategies include: (1) inland markets can be linked with domestic and international natural gas supplies by pipelines; (2) southeastern coastal regional gas demand can be meet in form of LNG.

Now in China three LNG receiving terminals are in the process of planning, where on coastal line on Yangtz Delta, Zhujiang Delta and E.S. Fujiang Triangle.

Chapter 2 Economical and technical analysis of LNG chain

Introduction

In 2001 LNG imports/exports grew to 143 billion cubic meters (BP, 2002), LNGC stood at 127 ships, with 22 on order and 7 under option. More than 20 new LNG receiving terminals are either planned or proposed, and more than 10 are under either renovation or construction (EIA, 2001).

One factor contributing to the world growth in the LNG trade is the declining cost structure of all phases of the supply chain, which has allowed the cost at which LNG becomes economic to fall within the range of natural gas prices in market. Liquefaction costs between 1996 and 2000 averaged $230 per ton, compared with $560 per ton between 1986 and 1990. Between 1996 and 2000 the cost of a new tanker dropped by approximately 30 percent (Bamber, 2001). The construction costs for re-gasification terminals have seen similar decreases.

In this chapter, the LNG chain is identified from economical and technical points of view, the contractual characteristics and cost structure are discussed, further, the liquefaction costs of selected gas resources are listed.

2.1 Definition and technical analysis of the LNG chain

Liquefied Natural Gas (LNG) is produced from natural gas by the process of liquefaction, which cools the gas to minus 161 degrees centigrade (at which point it becomes a liquid) and reduces the natural gas to approximately 1/625th of its original volume, thereby allowing it to be transported over long distances efficiently by dedicated tankers, i.e. LNG carriers (LNGC). The complete liquefaction processing facilities are referred to an “LNG train”, after its arrival at destination LNG is regasified and used primarily for generation of electricity, as utility gas and as an industrial fuel. The whole process from gas production to the end-users is called the LNG chain.

2.1.1 Definition and elements of the LNG Chain

The physical steps in the production and use of LNG include (Figure 2.1):

1. Gas Production. Natural gas is extracted from the reservoir and piped to an onshore liquefaction plant.

2. Liquefaction Plant. At the liquefaction plant, the gas is turned into a liquid by cooling it to –161°C and is then stored in tanks to await shipping.

3. LNG shipping. The liquefied gas is transferred to a purpose-built double-hulled tanker and shipped at atmospheric pressure. The LNG is kept at –161°C by an auto-refrigeration process.

4. Receiving and re-gasification terminal. At the re-gasification terminal, LNG is pumped from the ship to onshore storage tanks. It can then be returned to its gaseous state and distributed onwards by pipeline for end use as a fuel (power generation, fertilizer industry, gas distribution, etc.)

Source: BP

Figure **2.1** **Scheme of LNG chain**

These steps are often called the "LNG Chain" because all these activities are linked (Figure 2.1). All these activities must take place simultaneously in order to ensure natural gas flow to all parties as planned. The first three activities are typically referred to as upstream activities while the last is referred to as downstream activities.

2.1.2 Process of the LNG chain

1. **Pre-treatment of natural gas**

   As shows in Figure 3.1, this chain begins with the natural gas source, which may require treatment for removal of constituents corrosive to equipment, such as sulphur, carbon dioxide and mercury, and the removal of water and heavier hydrocarbons which could freeze in the subsequent liquefaction process and block process plant.

2. **Liquefaction process**

   In the liquefaction process, the treated gas is cooled to –161°C, at which its main component, methane, forms a colorless, odorless, non-toxic liquid at atmospheric pressure. Several proprietary processes exist to achieve the production of LNG, but in essence these work much like a domestic refrigerator, whereby a pressurized mixture of gases, known as a multi-component or mixed refrigerant, is rapidly reduced in pressure to lower its temperature by being flashed through a partially open valve. This cooling process is known as the Joule-Thompson effect. The resulting refrigerant stream is then used to cool the incoming natural gas by passing the two streams through heat exchangers. The refrigerant gases are then recompressed, cooled and the cycle repeated.

3. **LNG Shipping**

   LNG, is stored at –161°C at atmospheric pressure in insulated cryogenic tanks, often more than 100,000m^3 in size and capable of maintaining the gas in liquid form, even in the world's hottest climates. Purpose-built ocean-going cryogenic tankers, with capacities ranging up to 145,000 m^3 convey the LNG to market, during which time a small quantity of the LNG is allowed to boil off as vapour, which is then used to power the ship's engines.

4. **Re-gasification**

   Once the tanker arrives at its destination – the import terminal – LNG is pumped ashore to storage tanks similar to those at the liquefaction plant. To convert LNG back to its gaseous state to meet local energy demand, LNG is vaporized, or regasified, by heat exchange – generally with seawater. The quality specification of the resulting gas is set by pipeline transmission companies and end users, and distributed by conventional gas pipelines.

2.2 Commercial features of the LNG chain

With respect to LNG trade, a lot of parties are involved in the LNG chain: the entities that sell LNG (each called a `seller'), the entities that buy LNG (each called a `buyer), service providers and vendors. A seller is often a consortium of several sponsors (`sponsor' or `sponsors').

The commercial activity takes place under long-term contractual arrangements. A seller is often owned by the nation where the gas reserves are located (host country). There is always a high involvement of the host country's government in the sale of gas as is typical in oil and gas production. There have traditionally been strong creditworthy electric/gas utilities or national gas utilities, on the buying side.

2.2.1 Ownerships of the LNG chain

1. Gas fields

The gas field is typically controlled by the government of the host country.

2. Liquefaction plant

The ownership pattern of some of the liquefaction plants, which are currently operating or are planned, is provided in Table 2.1. It can be observed that liquefaction facilities are also controlled by the national oil companies of the host country which export LNG or by trans-national companies which have substantial experience in the area of gas/LNG.

3. LNG Shipping

Traditionally, shipping has been arranged either by the seller or the buyer of LNG. In cases where shipping has been arranged by the buyer, the buyer has entered into a charter agreement with the shipping company and the contractual arrangements protect the interests of the buyer of LNG.

Table 2.1 Ownership of liquefaction plants

No.	Country	Plant	Ownership
1.	U.S.A	Kenai	Philips, Marathan Oil
2.	Libya	Marsha	Sirte Oil
3.	Abu Dhabi	Das Island	ADNOC, Mitsui, BP, Total
4.	Indonesia	Arun	100 % Ownership of liquefaction facility by Pertamina Operations: Pertamina, Mobil, JILCO
5.	Indonesia	Bontang	100 % Ownership of liquefaction facility by Pertamina Operations: Pertamina, Total, Unocal
6.	Brunei	Lumut	Brunei Govt, Mitsubishi, Shell
7.	Malaysia	Bintulu MLNG I & II	Petronas, Mitsubishi, Shell
8.	Australia	NWS	Woodside, BHP, BP, Chevron, MiMi, Shell
9.	Qatar	Qatargas	QGPC, Mobil, Total, Mitsui, Marubeni
10.	Qatar	Rasgas	QGPC, Mobil
Likely by year 2005			
1.	Oman	Bimmah	Oman Govt., Shell, Total, Mitsui, Marubeni, Partex
2.	Yemen	Yemen	Total, Yemen government, Yemen LNG Co., Exxon, Yukong
3.	Russia	Sakhalin	Marathon Oil, Mitsui, Shell, McDermott, Mitsubhishi

Source: Gujfuel. (2002).

4. Receiving and re-gasification terminal

The ownership pattern of some of the receiving and re-gasification terminals which are currently in operation is listed in Table 2.2. It can be observed that the end users of LNG such as power or gas utilities have taken sizeable stakes in the receiving terminal. For example, in Japan, Tokyo Electric along with

Tokyo Gas own the Negishi and Sodegaura terminal, Tokyo Electric owns the Futtsu terminal.

Table 2.2 Ownership of receiving and re-gasification terminals

No.	Terminal & Country	Owner	Source of supply
		Japan	
1.	Negishi	Tokyo Gas, Tokyo Electric	Alaska, Brunei
2.	Sodegaura	Tokyo Gas, Tokyo Electric	Brunei, Abu Dhabi, Malaysia, Indonesia
3.	Himeji	Kansai Elec.	Indonesia, Australia
4.	Futtsu	Tokyo Electric	Malaysia, Australia, US, Abu Dhabi
5.	Yokkaichi	Chubu Elec.	Australia, Indonesia
		Other Asia	
1.	Pyeong Taek (Korea)	Korea Gas Corp	Indonesia, Malaysia, Brunei, Australia
2.	Inchon (Korea)	Korea Gas Corp	Indonesia, Malaysia
3.	Yung - An (Taiwan)	Chinese Petroleum Corp	Indonesia, Malaysia
		Europe	
1.	Panigaglia, Italy	Snam	Algeria
2.	Barcelona, Spain	Enagas	Algeria / Libya
3.	Fos-sur-Mer, France	Gas de France	Algeria
4.	Monitor, France	Gas de France	Algeria
5.	Zeebrugge, Belgium	Distrigaz	Algeria
6.	Huelva, Spain	Enagas	Algeria
		U. S.	
1.	Everett, Mas	Distrigas	Algeria
2.	Lake Charles, La	Trunkline LNG	Algeria
3.	Cove Point, Md	Cove Point LNG	Algeria

Source: Gujfuel. (2002).

2.2.2 Contractual characteristics of LNG

There are some contractual characteristics to a LNG project, which can be summarized below:

1. **Long term contracts**

The long term of contracts are necessary in order to achieve a price acceptable to buyers and acceptable financing to build the project. The seller and buyer are closely linked by long term contracts, usually 20 to 25 years for each new sales transaction. Spot market and short-term relationships are not commonly observed even now, but it is changing and will be discussed later.

2. **Take-or-pay obligations**

There must be significant front end infrastructure investment for each ton of LNG delivery capacity. The critical mass of infrastructure and, therefore required financing for an LNG project must be very large, in order to achieve production quantities adequate for realization of economies of scale. This requires high levels of take-or-pay (TOP) obligations in the off take agreements to ensure adequate assured returns on these investments. TOP contracts are believed to facilitate the development of infant gas markets, on the other sides, their impacts on mature gas markets are argued (Henning, 2000).

2. 3 Cost structure of the LNG chain

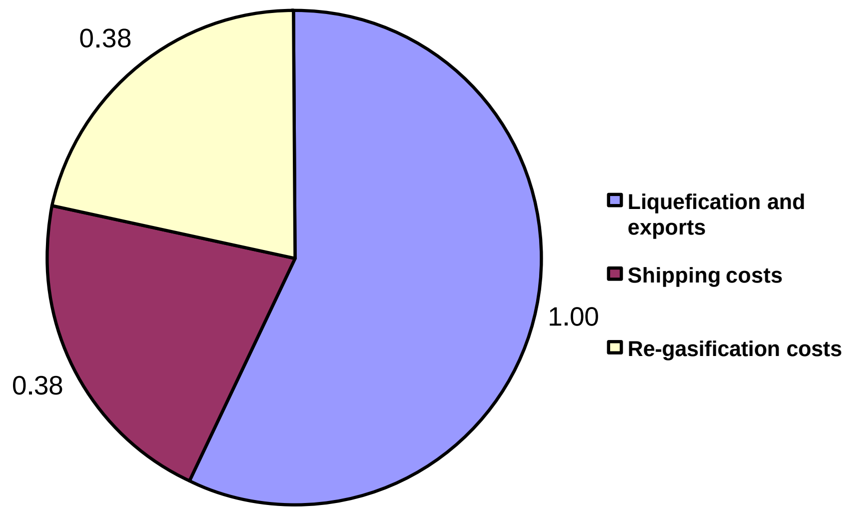
Developing an LNG chain is a high investment, long gestation activity. In a chain there are a large components, consisting of the liquefaction facility at the source of the gas, the LNG tanker, the receiving terminal and re-gasification facility at a location near a gas distribution network. To make the economics of the supply chain viable, its components must all be large scale.

The LNG chains costs consist of three main parts:

- FOB supply costs, which incurred in the process of gas exploitation and development, liquefaction and exports.
- Shipping costs, which stemmed from shipping transport
- Re-gasification costs, which occur in imports terminal and include handling costs and vaporization costs.

There were a lot of studies which reported cost structure about LNG chain (Anwar, 2001;Favennec, 2002). For example, BP (2002) presented cost structure of a typical LNG chain:

A typical single LNG process train producing 3 to 4 million tpa (ton per annum) of LNG requires a gas source of around 85-115 billion cubic metres – a very large gas field. The first LNG train may take up to five years to design and build, and could cost around $1 billion including its infrastructure; plus a further $200-300 million for the import terminal, and a fleet of three to six tankers – depending on the distance to market – each perhaps costing $175 million. For an LNG supply chain spanning 3200-4000km, the overall cost could typically be around $1.8 per million BTU (British thermal units) of energy supplied to the customer, on top of the price paid for natural gas at the receiving plant (see Figure 2.2).



Notes: The above graph shows indicative costs of each stage of the LNG supply chain. Basis: 4.5 million tonnes per year export and import, with 3200 km one way trip, over a 20-year period. Source: BP

Figure 2.2 LNG supply chain costs

(US$/MMBtu)

Table 2.3 Indicative investments in LNG value chain

Activity	Capital cost (in billion US $)	Build-up of costs of delivered LNG (US $/MMBtu)
Gas production	1 – 2	0.5 - 1.0
Liquefaction plant	2 – 3	1.7 - 2.4
LNG shipping	1 – 2	0.8 - 1.6
Receiving & re-gasification terminal	0.4 – 1	0.5 - 1.0
Total	**4 – 8**	**3.5 - 6.0**

Source: Gujfuel

Gujfuel (2002) showed a typical range of investment in the LNG chain for a two train grass-root project (typically 5 MMTPA) and their impact in terms of delivered LNG cost (Table 2.3).

Moreover, another study (Favennec, 2002) stated his findings in terms of LNG supply chain costs (Table 2.4).

Table 2.4 Transmission costs in a gas chain (US$/MMBtu)

Activity		Transmission costs
Exporting country	Wellhead price	0.6
	Transmission cost	0.2
Ocean transportation	LNG chain cost	2.5
Importing country	Transmission cost	0.7
	Distribution cost	2.7
Average delivered price		6.7

Source: Favennec

From the above studies it was observed that LNG chain costs varied from place to place. In BP’s report the supply chain cost is 1.8 US$/MMBtu excluding feed gas cost, but it is 2.5 and 3.5-6.0 US$/MMBtu from the others. One of the reasons why costs of LNG chain deviated largely is that they are determined and sensitive to all those factors such as gas resources, liquefaction plants, shipping voyages, destination and receiving terminals. Therefore they varied from place to place. Moreover, another main reason is that different assumptions and definitions of the LNG chain were used in their calculations of LNG chain costs. For example, in BP's calculation feed gas cost is excluded, so it seems lower. If only the range of chain from liquefaction to receiving terminal is considered, Favennec's result can be modified to 3.4 US$/MMBtu and Gujfuel's conclusion can be revised to 3.0-5.0 US$/MMBtu, which looks similar.

Their common findings are that liquefaction costs occupied more than half of the total costs.

2.4 Gas resources and FOB supply costs

2.4.1 Requirements to gas resources

In order to ensure the success of one LNG project, the natural gas reserves need to be adequate for many years of production of LNG at an annual rate large enough and at a cost low enough to attract the interest of both seller and buyer. Otherwise, any physical disadvantages of the gas in quantity of reserves, quality of reserves and location can jeopardize a proposed project.

- Quantity. Enough proven gas must be physically accessible and contractually dedicated to the LNG contract.
- Quality. The quality of gas present in the reserves affects the cost of production of gas as well as the price of the finished product. If the composition of the gas is high in Carbon-dioxide (CO_2), the additional processing cost to separate the CO_2 and re-inject it into the field or into separate reservoirs can render the production cost uneconomical. On the other hand, the presence of saleable heavier gas fractions such as ethane and propane in the gas enhances the market value of the gas.
- Location. If the location of the gas is remote from markets, the cost of transportation can be as much as one-third of the delivered cost of LNG. Profit of a long distance LNG supply project may be thin if it is forced to

engage in pricing competition with LNG produced closer to market. This impact will be discussed and shown in the case study in Chapter 5.

2.4.2 FOB supply costs

FOB supply costs of LNG refer to the cost of feed gas to LNG liquefaction facilities and the unit cost of liquefaction facilities on a green-field (where relevant), expansion, and marginal operating cost basis. Therefore, FOB costs consist of two components: the into-plant feed gas costs and the cost of liquefying the gas.

Table 2.5 Estimated Into-plant Feed Gas Costs

Country	Project	US dollars per MMBtu
Atlantic Basin		
Trinidad	Port Fortin	0.50
Norway	Snøhvit	1.00
Mediterranean		
Algeria	Skikda/Arzew	0.50
Middle East		
Qatar	**RasGas/QatarGas**	**0.50**
Iran		0.50
Pacific Basin		
Indonesia	Arun/Bontang	0.70
	Tangguh	**0.80**
Australia	**Northwest Shelf**	**0.30**
	Timor	0.70
	Scott Reef	0.80
	Gorgon	0.80

Source: Cambridge Energy Research Associates.

a) Feed gas costs

According to a study of CERA (2002), Table 2.5 represents their estimated cost of gas into liquefaction plants (including all taxes, royalties, and reasonable return on investment) at some selected LNG sources. As such they must be regarded as indicative cost averages for each location. In some cases profit margins could be reduced in order to improve the competitive position of specific projects.

b) LNG Liquefaction Costs

The second element of FOB supply costs is the cost of liquefaction. CERA (2002) estimated liquefaction costs (Table 2.6) on three different bases:

- **Greenfield project.** The amount needed per unit of output to earn a specified internal rate of return (IRR) on the development of a green field LNG project excluding upstream development and gas gathering and transmission costs.

Table 2.6 Estimated FOB LNG Costs (US$ per MMBtu)

Country	Project	Greenfield	Expansion	Marginal
Atlantic Basin				
Trinidad	Port Fortin	—	1.35	0.75
Norway	Snøhvit	2.25	—	1.30
Mediterranean				
Algeria	Skikda/Arzew	—	1.35	0.75
Middle East				
Qatar	**RasGas/QatarGas**	**—**	**1.25**	0.75
Iran		1.55	1.35	0.75
Pacific Basin				
Indonesia	Arun/Bontang	—	1.55	1.00
	Tangguh	2.00	**1.80**	1.10
Australia	**Northwest Shelf**	**—**	**1.35**	0.55
	Timor	2.05	1.75	1.00
	Scott Reef	2.15	1.85	1.10
	Gorgon	2.15	1.85	1.10

Source: Cambridge Energy Research Associates.

- **Expansion project.** The amount needed per unit of output to earn a specified IRR on the expansion of an existing LNG facility. As with greenfield cost estimates this excludes upstream development and gas gathering and transmission costs.

• Marginal cost. The amount needed per unit of output to cover variable operating costs of an existing facility.

Summary

In this chapter LNG chain and technical and economical features were identified, especially costs of LNG chain were discussed deeply.

The LNG chain includes gas production, liquefaction plant, LNG shipping, receiving and re-gasification terminal, and send-out pipeline to those end users. All these components link together and need to work simultaneously.

The ownership on those parts in LNG chain varied from place to place, normally gas production and liquefaction plant are owned by gas source government, receiving and re-gasification terminal and send-out pipeline are under control by the buyer such as gas company or electric industry, shipping is owned by either seller or buyer of LNG. However, there is a trend now that more buyers intend to control LNG chain from shipping to receiving terminals.

Total costs of LNG chains mainly consist of three parts: FOB supply costs, transportation costs, and re-gasification costs. The proportion of three parts varies from project to project, but it is found that FOB supply costs account for more than half of the total costs. Therefore, gas resource plays a key role in optimizing LNG chains.

Chapter 3 Economical and technical analysis of LNG shipping

Introduction

LNG tankers began operating in the mid-1960s. Today 130 ships are currently in service worldwide, The Lngoneworld web site gives further information (http://www.lngoneworld.com). LNG tankers are extremely complex vessels, and relatively few shipbuilders are capable of building them (the LNG shipyards see Appendix C.

The average construction time of LNG ships was around 36 months. As a result of improved efficiency in ship production techniques, the time to build a ship has been reduced to about 27 to 30 months.

This chapter focuses on economic and technical analysis of LNG shipping. The main objective in this chapter is to discuss the cost structure of shipping costs and to estimate shipping costs.

3.1 Capacity and containment systems of LNG ships

LNG carriers are generally classed or referred to by the volume of LNG they can load and by the type of containment system.

3.1.1 Capacity

Unless logistic limitations dictate the use of smaller vessels (e.g., deliveries to mid-size gas companies in Japan or to smaller terminals in the Mediterranean), the size of LNG ships has been steadily increasing. Improved technology has played a part, but by far the most influential factor has been the economic one of reducing the unit cost of delivering the product. However, the size has now reached a controlling parameter—the size of vessel most terminals have been designed to accept. Iversen (1992) investigated worldwide LNG terminals and found that “a maximum draft at arrival of 11.5 meter may be desirable from the point of view of terminal access”.

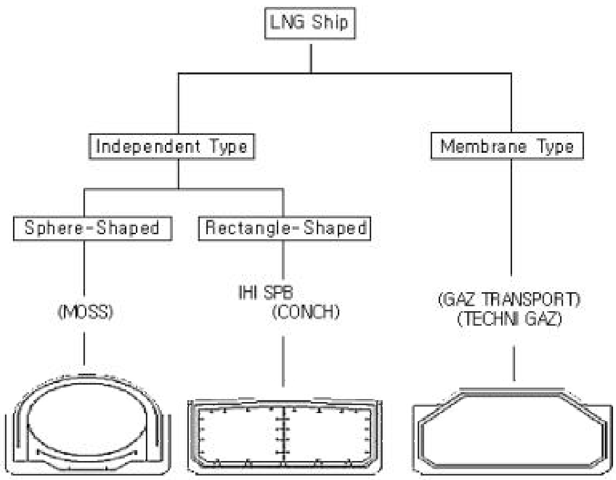
Then he argued that this draft limitation made it difficult to introduce an efficient LNG carrier with a capacity much above 165,000 m^3.

Table 3.1 shows the distribution of ship size of the 127 LNG ships in operation in mid-2001. In addition, as of August 1 there were 49 ships on order, all of which have capacities between 135,000 and 145,000 cubic meters.

Table 3.1 LNG Tankers in Operation

Type	Capacity (cubic meters)	Number in Service	Percentage (%)
Small	18,000 to 50,000	16	12.6
Medium	50,000 to 100,000	15	11.8
Large	Greater than 100,000	96	75.6
Sum		**127**	**100**

Source: Cambridge Energy Research Associates.



Source: CERA

Figure 3.1 Categories of LNG carrier

3.1.2 Containment systems

There are three basic types of containment systems in use today: Kvaerner Moss, membrane, and self-supporting prismatic (Figure 3.1). In each of the systems the LNG is carried at atmospheric pressure and is kept cold by the use of insulation and through some of the LNG boiling off. In the most modern ships boil-off is under 0.15 percent per day and is generally used to fuel the ships' engines. The characteristics of each of the containment systems are described below.

a) Kvaerner Moss design

The basic Kvaerner Moss design is a self-supporting spherical tank. Where the spheres penetrate the upper deck, a hemispherical steel tank cover is fitted and usually painted a light color to reduce boil-off.
There are 67 vessels (63 of over 124,000 cubic meters) in operation with the Moss design, representing just over 50 percent of the LNG fleet (CERA, 2002).

b) Membrane design

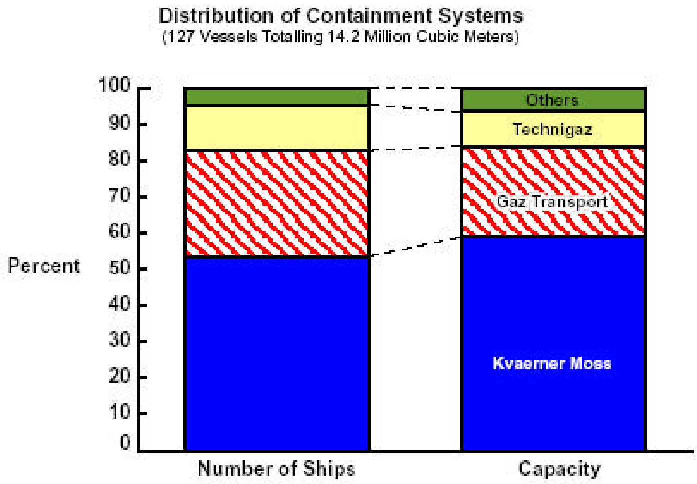
There are two techniques involved in the membrane containment system, the Gaztransport and the Technigaz designs. In each design the cryogenic lining of the membrane tank bears the cargo load and transmits it to the vessel's hull. Initially these two designs were in competition with each other, but the two companies merged in 1994 and a new company formed, known as Gaztransport & Technigaz (GTT). A ship owner can specify which of the two techniques he wishes to use since both are still available.
There are 54 membrane-type vessels in operation today, of which 34 are larger than 120,000 cubic meters (CERA, 2002).

c) Self-supporting prismatic design

The first LNG vessels built in the 1960s used a self-supporting system, known as the Conch system, and four of these vessels are still operating today. The modern self-supporting design was developed by IHI in Japan and was used in two 89,880 cubic meter ships built in 1993 and employed on the Alaska (Kenai)-to-Japan trade.

d) Division of LNG fleet by ship type

The 127-ship LNG fleet in operation in mid-2001 is divided by containment system as shown in Figure 3.2.



Source: Cambridge Energy Research Associates

Figure 3.2 Distribution of containment systems

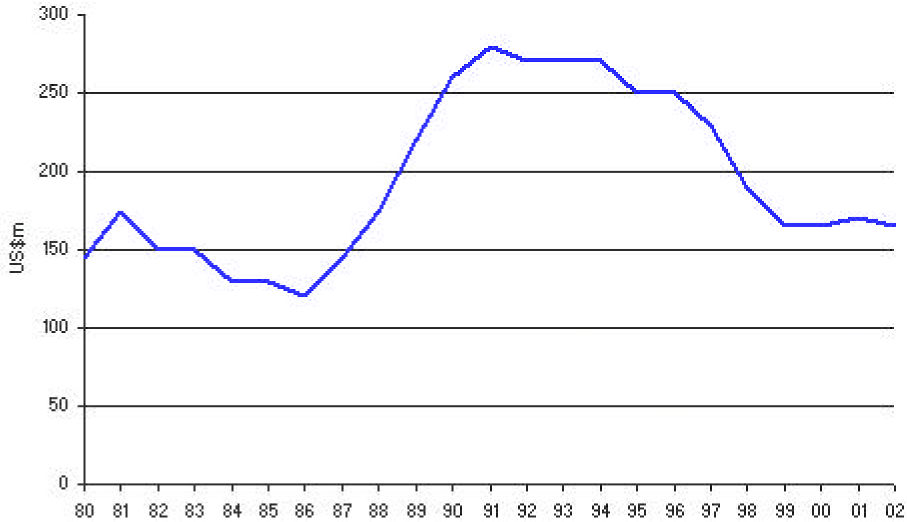
(127 Vessels Totaling 14.2 Million Cubic Meters)

Although over 50 percent of the ships in operation are of the Kvaerner Moss system, the order book tells a different story. Only about 26 percent of the 49 ships on order in mid-2001 were of this design, with the remainder being membrane design (CERA, 2002).

For many ship operators both the Kvaerner Moss and the membrane systems are considered acceptable designs, with the decision often being dictated by the price and the availability of the berth spaces to build the ships. The difference in distribution of ships on order and those in operation results from two factors. First, Samsung and Daewoo in Korea have been successful in capturing about 50 percent of the new orders, and these yards only offer the membrane design. Second, membrane ships can provide more flexibility in a trading environment than a Moss design. A membrane tank can usually be cooled down more rapidly than a Moss tank. As a result, the trader has the option of unloading the entire cargo. Normally some LNG (referred to as the heel) is left in the tanks to keep them cold on the return voyage since the time taken to cool down on return to the loading port is thereby minimized. In addition, the LNG terminals in Boston (United States) and Montoir (France) are upstream of bridges that can restrict access to Moss ships, which have a much higher superstructure than membrane ships.

3.2 LNG Shipping Costs

An LNG tanker typically costs $165 million (Figure 3.3), or three times the cost of a crude oil carrier of similar tonnage. The high cost and complexity of LNG tankers is a result of the advanced containment systems necessary to transport liquefied natural gas.



Source: Drewry shipping consultants

Figure 3.3 New building price of 125,000/138,000 m^3 LNG tanker

(million US$)

3.2.1 Capital costs

The prices charged by shipyards for LNG ships has varied considerably over time, reaching a peak of US$300 million in the early 1990s but declining to less than half that price for ships ordered in the first quarter 2000 (Figure 3.2). One of the main factors in the price level has been the degree of competition both between yards and in the demand for all types of bulk carriers, since the hulls for LNG ships are built in the same docks.

The price of LNG ships has risen from the low level reached in 2000, and in mid-2001 was around $170–$180 million for the typical 138,000 cubic meters ship for delivery in 2004–05. It is possible that prices could increase further since the order books in many yards are now close to being full. Furthermore, it is expected that orders for VLCCs will increase as a result of global oil flows and new regulations forcing ship owners to replace aging vessels.

Source: Mokrane,Yataghene, GTT

Figure 3.4 The relationship between shipbuilding price and ship capacity

Figure 3.4 shows the relationships between shipbuilding prices and ship capacities (Mokrane, 2002) based on 2001/2002 shipbuilding contract prices. The equation is:

$$\text{Price}_{\text{capA}}=\text{Price}_{\text{CapB}} \times (\text{CapA}/\text{CapB})^{0.623}$$

Packer (1993) also ever gave the similar equation: a +30% increase in gross capital cost for a 200,000 m^3 ship and +15%increase in gross cost for a 160,000 m^3 ship versus the basis 130,000 m^3 ship. This estimation is in line with the research result of Mokrane (2002), as shown in Figure 3.4.

Based on Figure 3.3 and following this equation, the shipbuilding prices of typical ships are estimated and shown in Table 3.2.

Table 3.2 Estimated shipbuilding price and charter rate

Ship capacity (cubic meters)	125,000	138,000[§]	147,000	160,000	200,000
Shipbuilding price (million US$)	155	165[§]	172	181	208
Bareboat charter rate (US$ per day)	51,926	54,822	57,261	60,354	69,333
Operating costs (US$ per day)	11,071	11,786	12,286	12,929	14,857
Time charter rate (US$ per day)	**63,209**	**67,313**	**70,158**	**73,825**	**84,568**

Notes: §-actual price of a ship and as a benchmark

The translation of the capital cost into a daily charter rate (bareboat charter) for the vessel depends on the rate of return that a ship owner requires to service debt and to earn a profit, the cost of capital, and the period over which the owner expects to recover his investment. Given the assumptions as shown in Table 3.3, the daily charter rates of typical ships are estimated and shown in Table 3.2.

Table 3.3 LNG carriers cost assumptions

Days available	350	per year
Cost per ship (millions US$)	165	for 138,000 cubic meters ship; costs for other ships see Table 3.2
Operating cost (non-crew percent ship cost)	1.00%	of ship cost annually
Crew cost (percent ship cost)	1.25%	of ship cost annually
Percent financed	75%	
Interest rate	6%	interest during construction is capitalized
Debt period	10	Years
Depreciation period	20	years straight line
Construction period (years)	3	
Target internal rate of return on equity	10%	

The estimations are conducted based on internal rate of return (IRR) analysis (Drewry, 1996, p9-10). Moreover, all these calculations are conducted by the programs developed by Drewry Consultant and details of calculations see Appendix G.

CERA (2002) estimated that:

> For a vessel costing $175 million, a ship owner charging a bare boat daily hire charge of $55,300 plus operating costs would earn around 10 percent on his investment over a 20-year period.

Comparing the daily hire charge estimated by CEAR, the estimated results shown in Table 3.2 can be acceptable.

3.2.2 Operating costs

The operating costs for a vessel include:

- crew costs
- maintenance: routine engineering, dry docking
- fabric maintenance
- insurance: hull, P&I, loss of hire, etc.
- administration
- regulatory costs
- management fee

CERA(2002) estimated that these costs could vary widely between ship owners from a low of under $4 million to as high as $6 million per year ($10,000 to $16,500 per day).

In this study operating costs are assumed as 2.25% of ship cost annually and operating costs are shown in Table 3.3. Therefore, according to the assumptions, the annual operating costs are in the range from 3.9 to 5.3 million US$, which also can be acceptable.

Based on capital costs and operating costs, the time charter equivalent (TCE) rates of LNGC are estimated and shown in Table 3.3 too. These estimated TCE rates are also similar to the estimated value by CERA.

3.2.3 Voyage costs

Normally, the charter rate for a vessel will cover the capital costs and the operating costs listed above. In addition, the party chartering the vessel will have to pay the costs of fuel, port charges and canal fee if the voyage involves transit through the Suez Canal (Golar,2001).

Fuel costs consist of boil off cost and bunker cost, which will depend on the way in which the ship is operated. Most ships are able to use gas that is boiled off naturally from the cargo as a fuel. Although the technology also exists to re-liquefy the boil-off gas, but only one ship currently in operation has these facilities fitted. However, the boil off gas will not normally provide sufficient fuel to meet all the ship's needs. Some ships have the facility to boil off additional LNG, which allows the operator to choose between this option and using fuel oil to meet the vessel's fuel requirements. The decision will be dictated by the comparative costs of fuel oil and LNG and the convenience of loading fuel oil at the loading port, the discharge port, or at an intermediate port during the voyage.

Port charges are port specific and vary widely among locations, ranging from $30,000 per visit to in excess of $100,000. Currently the canal fees which is the equivalent of about $0.15 per MMBtu to the cost of delivering LNG for a 138,000 cubic meter vessel is added as ship transiting the canal on both its laden and ballast voyages.

3.3 Development in technology and market

3.3.1 Technology development

The main change in LNG ship design over the past 30 years has been the increase in the capacity of the vessels, from the initial ships with capacities of 27,400 cubic meters to ships now on order with capacities of 145,000 cubic meters. Designs for larger ships with capacities of 200,000 cubic meters or more have been developed, which is likely to occur only if a new project dictates that the economies of scale associated with larger vessels is sufficient to offset the potential drawback of the lack of flexibility inherent in trading with larger vessels. Therefore, the need for ships to have the flexibility to trade LNG into as many terminals as possible is making 145,000 cubic meters popular.

It is unlikely that there will be any major new developments in the containment system in the immediate future, but it is possible that the propulsion systems could change. LNG ships are some of the only vessels still using steam turbines. A change to diesel turbines would bring the fleet more closely into line with the rest of the world's shipping fleets. The ease of using boil-off gas in steam turbines has been one reason for diesel turbines not being used, but the technology now exists to use boil-off gas in gas turbine engines.

3.3.2 Market changes

a) Charter market for LNG ships

There is not yet an open market for chartering LNG ships. Projects that have chartered ships in the past have negotiated a deal with ship owners based on the project's specific requirements. Charter rates have generally been kept confidential between the ship owner and the project. The information available suggests that rates have been closely related to the cost of new ships and may have been as high as $50 million per year ($130,000 per day) when the cost of new ships reached $300 million.

At present charter rates are with a linkage to U.S. natural gas prices. Some of the elements of a charter market have developed over the past three years as projects and companies have sought to charter the few ships not committed to a project on a long-term basis. The rates agreed for these ships have shown some correlation with US gas prices. In 1999, when Henry Hub prices averaged around $2.25 per MMBtu, secondhand vessels were chartered out at around $40,000 per day (which still gave the owners a good return on vessels that had long been amortized). As Henry Hub natural gas prices rose through 2000 and into early 2001 to a peak of over $9.00 per MMBtu, charter rates are reported to have increased to nearly $150,000 per day. Indeed, some charter rates were negotiated with a linkage to US natural gas prices.

As new ships have come into service since mid-2002 onwards, it is possible that an open market for chartering LNG ships could develop, as many of the new vessels do not yet have a long-term commitment. The level of prices in the various LNG markets and the opportunities for arbitrage between them are expected to be important factors in the setting of charter rates.

b) Shipping control and sales contract

The question whether to sell LNG on an FOB[1] or ex-ship basis has been addressed since the first LNG trades started in the 1960s. Selling on an ex-ship basis gives the gas project control of the shipping and facilitates the optimization of plant output with the shipping. It also provides the project with confidence that the ships will be available and will be operated in its best interests. However, it exposes the project and its shareholders to additional capital expenditure, or if the ships are chartered, it commits them to revenue payments for the 20-year or more life of the project. In an FOB sale the costs of the ships are transferred to the LNG buyer, but it can be argued that the risks to the project are increased when it does not have control of the shipping.

In the past few years, as short-term trading has increased, there has been an additional consideration for both buyers and sellers. Control of shipping has become important in allowing players to take advantage of short-term market opportunities. For LNG sellers, control of shipping can position them to sell surplus LNG cargoes. For LNG buyers, it can provide flexibility to help manage variations in demand or to resell surplus cargoes.

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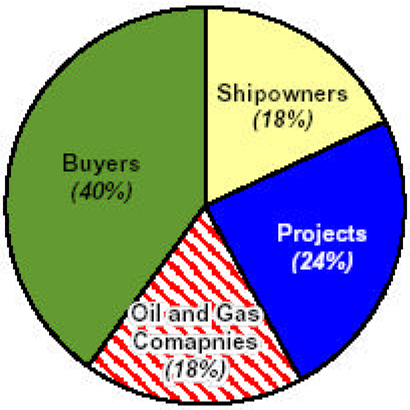
[1] *Ex-ship and cost-insurance-and freight (CIF) sales are essentially the same in terms of control of the shipping. The main difference is the point at which ownership of the cargo changes hands. In an ex-ship contract this is when the LNG is discharged. In a CIF contract, ownership transfers on loading or at an agreed point on the voyage. Under a CIF contract, the seller's price includes cost of product plus the cost of marine insurance and transportation to the foreign port.

**In a free-on-board (FOB) deal, the seller quotes the buyer a price that covers all costs up to and including delivery of goods aboard a vessel at a named port. Once the goods are delivered, the seller's responsibility ends.

The LNG business has developed with a mixture of FOB and ex-ship sales. Japanese buyers, who still represent over 50 percent of the LNG market, tended in the past to favor ex-ship purchases (which accounted for about 80 percent of their LNG purchases in 2000), whereas in the Atlantic Basin and Mediterranean buyers have tended to prefer FOB purchases. Overall, in 2000 around 65 percent of LNG was sold under ex-ship arrangements and 35 percent on an FOB basis. However, the position is reversed for LNG contracts signed since 1995, with about 60 percent on an FOB basis and 40 percent on an ex-ship basis (CERA, 2002). This reflects the increased importance LNG buyers (especially gas companies such as Korea Gas) are placing on control of the shipping.

CERA (2002) addressed that LNG will continue to be marketed on a mixture of ex-ship and FOB bases, but FOB sales are likely to continue to represent the majority of new contracts. The order book for new ships (see Figure 3.5) supports this expectation.

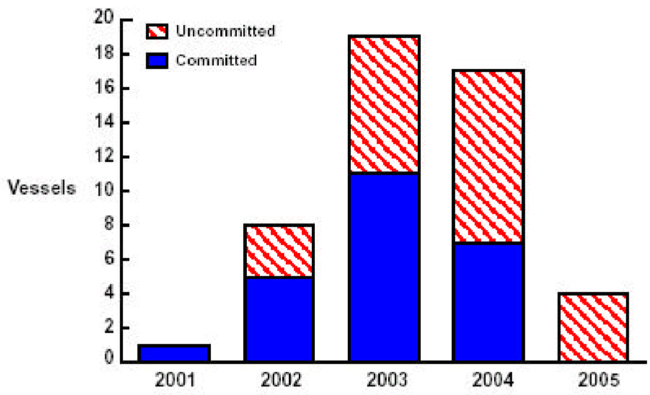


Source: Cambridge Energy Research Associates.

Figure 3.5 Distribution of ships on order by type of buyer

c) Available ships for short-term LNG trading

The short-term trading of LNG can take place only if ships are available to move the LNG to market. As a result, the availability of ships has become the main constraint on the expansion of short-term trading, and there has been strong competition to secure these few uncommitted vessels when they have become available. This constraint will be eased over the next few years as new ships currently on order are delivered into service.



Source: Cambridge Energy Research Associates.

Figure 3.6 Vessels on Order as of September 2001

(Total=49 Vessels)

Figure 3.6 shows the number of ships to be delivered over the next four years divided into those that are committed to a specific project or trade route with long term contracts and those that currently have no fixed employment. The former category includes ships ordered by projects (Malaysia Tiga, Nigeria LNG, Australia North West Shelf, and Qatargas) and those ordered by buyers for specific trades (e.g., Trinidad to Spain, Qatar to Korea). The uncommitted ships include those ordered by oil and gas companies and by ship owners plus some of the ships ordered by buyers, which have not been allocated to a specific project.

By the end of 2002 there will be 3 additional uncommitted ships available, and the number will grow to over 20 by 2005. It is likely that some of these ships will eventually be committed on a long-term basis as new projects are developed and new contracts signed. However, a further 34 options have been announced that will, if confirmed, add to the number of ships available by 2005 (CERA, 2002).

Summary

This chapter focuses on LNG shipping. It is found that:

- There are 3 main designs in LNG tankers. Nowadays membrane design ships dominate the order book because they can provide more operational flexibility to the LNG trader, dominate the order book.
- Although there is not yet an open market for chartering LNG ships, TCE rates can be estimated by net cash-flow analysis and discounting techniques, such as Internal rate of return (IRR) used in this study.
- Based on 2001/2002 shipbuilding contract prices, the relationship between ship capacities and prices can be reflected by the equation:

$$Price_{capA}=Price_{capB}x(CapA/CapB)^{0.623}$$

- The building price of LNGC decreased. The price of a 138,000 cubic meter new ship reached close to $300 million in the early 1990s before falling to around half this level by early 2000. Now the price is 165 million US$. Therefore, at current level, a ship owner would need a charter rate of between $63,000 and $84,000 per day to cover financing and operating costs.
- Although over 60 percent of existing LNG contracts are on an ex-ship basis, there is an increasing trend toward free-on-board (FOB) deals as buyers seek more flexibility. Over 60 percent of the LNG contracted since 1995 has been on an FOB basis (CERA, 2002). Moreover, the pattern of ship ownership are changing, more buyers (directly or indirectly) order new ships instead of LNG project consortia.
- Safety remains of paramount importance to all the players in the LNG business. Continued vigilance will be required as ships age and new operators become involved in the business.

Chapter 4 Economical and technical analysis of LNG terminal

Introduction

The primary elements of the LNG receiving facility itself are berths for unloading the LNG tankers, storage tanks to receive the ship's cargo, and vaporizers to regasify the LNG for distribution to market centers through natural gas pipelines. The actual construction time of LNG imports terminals averages about 3 years.
When a new project of LNG receiving terminal is launched , the major factors that must be considered as following:

- Capacities of handling, storage and re-gasification must meet imports volume, send out requirements and logistics variability capacity, the of LNG
- Terminal location and marine situations to accommodate ship size, such as water depth, especially the depth of the channel to the jetty and the potential for silting
- Availability of onshore area and a right-of-way for the pipeline
- Safety

In this chapter planning of LNG receiving terminals and operation processes are identified. After that some new technical developments are described, then the re-gasification costs are discussed.

4.1 LNG terminal planning

4.1.1 Feasibility study

In the planning of LNG receiving terminals, a feasibility study (Bechtel enterprises and Shell gas & power, 2002) will be conducted to evaluate a wide range of regulatory, environmental, technical, community, economic, and social factors associated with building and operating an LNG import project at site, i.e. assessment of the STEEP factors (Social, Technological, Ecological, Economical and Political) (Schröder, 2002). Some activities during the feasibility study will involve field works, such as drilling for geo-technical reasons, taking soil and water samples, and conducting environmental site assessments. Others will involve consulting with the community and reviewing regulations and previous environmental studies. The key issues include:

- **Safety and security** of transportation, site operations, and emergency planning (the details are discussed in the next section).
- **Economics**, including the market for natural gas and electricity, financing and costs.
- **Technical suitability** of the LNG unloading, storage and Re-gasification system; and connections to the existing gas distribution systems. Related subjects include site acquisition, plant layout and configuration, thermal efficiency and cold utilization, water intake and discharge, and seismologic investigations.
- **Environmental impact assessment (EIA)**, including land use, air and water quality, endangered and threatened species, sensitive habitats (e.g., wetlands), dredging, visual impact, and environmental justice (Irving oil limited [IOL], 2002, pp 1-18).
- **Social impact**, including creation of jobs during construction and operation.

4.1.2 Risk analysis and site selection

It is important to keep in mind that public health and safety and property protection are important issues and must be appropriately addressed at the initial stages of an LNG project. The magnitude and extent of any damage from an LNG spill can depend on the proximity of the terminal and storage sites to other industrial and residential areas.

The risk analysis considers the major events which might cause an LNG spill, such as ship collision, grounding, or ramming; failure of the unloading arms or other major pieces of equipment; and damage to the facility from natural phenomena or unusual accidents. The risk analysis determines the extent of damage and the number of deaths and injuries which may result from a disaster and the probability that certain types of disasters would occur. The death probabilities from natural disasters are typically about 1 in 10 million (NTIS, 1977). The three main aspects of this analysis include:

- Fire radiation analysis—Addresses ignition of the pool of LNG and levels of radiation at specified points. This is used to determine the minimum separation distances and the amount of water needed to cool the adjacent equipment.
- Gas dispersion analysis—Determines the dispersion of vaporized LNG for various climatic conditions. The extent of a vapor cloud is used to determine the minimum distance to sources of possible ignition.
- Detonation analysis—Addresses the resultant blast from unconfined vapor explosions. This determines blast protection requirements and the safe distance for structures and equipment.

The results of these analyses are used to determine the *exclusion zone*—the area outside of which is considered safe for public access. They are also used to determine in-plant separation distances.

The hazards study must be conducted before finalizing the relative locations of storage tanks, vaporization facilities, and other power plant facilities. From a capital cost viewpoint, these facilities should be kept as close as possible to each other; however, safety considerations mandate minimum safe distances of anywhere from 200 to 800 meters. Enlarging the exclusion zone by 1 to 2 km from any public facility (such as a school, a hospital, or a highway) may be necessary.

4.1.3 Safety guidelines and regulations for LNG terminals

The risk analysis with equipments selection and operation procedures can comply with guidelines developed by Society of International Gas Tanker and Terminal Operators (SIGTTO), who urges the LNG industry to accept a wide range of equipment and procedures for the reduction of operational risk. The main publications include (Marc, 1998):

- Site selection and design for safety at LNG ports and jetties – Information paper No.14 SIGTTO, 1997
- Guidelines for hazard analysis as an aid to management of safe operations – ISBN 1 85609 054X, SIGTTO, 1992
- A guide to contingency planning for the gas carrier alongside and within port limits – ISBN 0 948691, SIGTTO/ICS/COIMR, 1987
- Dangerous goods in port. Recommendations for pot designers and port operators – Permanent international Association of Navigation Congresses (PIANC), 1985

In addition to SIGTTO guidelines, local regulations must be followed as applicable because safety requirements may vary from country to country.

4.2 Elements of LNG terminals

LNG is unloaded only in specialized terminals, which typically include a jetty and unloading equipment, where the tanker is connected to pipelines by articulated unloading arms and the cargo is pumped to ashore storage tanks, then vaporized to natural gas and sent out into commercial pipelines.
The marginal cost of either utilizing excess capacity at an existing Re-gasification plant with excess capacity or expanding the capacity of an existing plant would be far lower than the cost of building a new green-field facility (EIA, Dec, 2001). Therefore, most facilities are constructed with an initial operating capacity and built-in expansion potential that can be obtained by increasing any one of a number of factors that limit throughput, including number of berths, size of the receiving tanks, capacity of the vaporizers, and capacity of the send-out lines.

4.2.1 Berths and unloading jetties

a) Number of berths and time in port

A typical ship unloading requires about a 24-hour turnaround time, broken down as follows (Jeffrey, 2000):

- 4 hours for customs, immigration, custody transfer measurements, connecting the unloading arms, and cool down
- 12 to 14 hours unloading
- 6 to 8 hours for final custody transfer measurements and calculations, disconnecting unloading arms, provisioning, and deberthing.

Therefore, in an economic analysis, a reasonable scheduling assumption for one berth is one ship every 3 days. On the other side, the reasonable assumption for the time in each port of a LNG ship is one day.

There will be times when there will be delays such that the shipping, inventory, and send-out logistics must be flexible to accommodate occasional delays. Alternative mooring availability is also a consideration (EIA, Dec, 2001).

b) Jetties designs

All the unloading jetties today use very similar designs including:

- A trestle between the jetty and the shore, which supports the liquid and vapours lines
- An unloading platform often with two or three levels, which supports the unloading arms and the fire protection
- Two to four breasting dolphins for berthing the ships
- Six to eight mooring dolphins for mooring the ships

4.2.2 Storage tanks

The LNG is stored in large insulated tanks on shore only briefly, later pumped to Re-gasification facilities before it enters the distribution system.

a) Capacity

The capacity of storage tanks is roughly equivalent to twice the capacity of a single LNG ship (Energy Information Administration [EIA], December, 2001, p34). The receiving tankage must have the capacity to take the ship's cargo and must also be additional volume to accommodate schedule and send-out variability. EIA (December, 2001) estimated that ship storage costs is about 5 or 6 times of the equivalent on-shore storage, the best overall economic result is achieved by buffering logistic variability with additional tankage at the receiving terminal. Moreover, additional storage also facilitates erratic ship scheduling and spot cargos in responding to peak demand markets and general logistics management. Today the largest capacity of aboveground LNG storage tank is 180,000 m^3, which located at the Senboku LNG terminal, Japan (Takeyoshi 2001).

b) Types and structures

In either type of facility, the storage tanks represent a significant portion of the costs, and the gas industry has spent much time and money in research to develop effective storage systems. Storage tanks can be constructed as aboveground and underground. Aboveground tanks that were built today, the majorities are of the double wall, double bottom design with an outer pre-stressed concrete tank or an outer concrete wall. In terms of containment system, there are three main types of LNG storage tanks:

- Single containment tank
- Double containment tank
- Full containment concrete tank Single membrane tank

The double containment tank has the inner double wall tank and an outer concrete wall lined with 9% nickel steel designed to be able to contain the liquid but not the vapour.

The full containment concrete tank is lined with an inner shell of carbon steel to take up the liquid and provide a vapour-tightness barrier of the concreter container in case of a leakage. The outer concrete tank is also a protection against external impact. Normally the inner self-supporting “open top” tank is made of 9% nickel steel thermally insulated and covered with a suspended aluminium roof.

The inner tank is reinforced with several ring stiffeners. There is no pressure except the hydrostatic pressure from the liquid height and the wall thickness of the tank needs to be largest at the bottom and can successively be smaller. The bottom shell course may be 25-30 mm and the top shell course may be 10 mm depending upon the height and design.

Stainless steel, aluminium and 9% nickel steel can be used because they do not have a ductile/brittle transition temperature (Jörgen, 2001). All pipes for the loading or unloading the tank is through the roof and there are no other openings for access into the tank once the tank is completed.

c) Selection of types

Sham (2001) addressed that the type of LNG tank for the terminal has been selected based on safety analysis to evaluate the effect of a major LNG spillage due to an accident on a storage tank.

Table 4.1 Safety evaluation of different types of LNG tank

Type of tank	Scenario considered
Single containment tank	Collapse of the tank, spillage of the whole capacity in the impounding basin
Double containment tank	Collapse of the tank roof, the LNG remains in the secondary concrete container but evaporates
Full containment tank	No collapse is considered

Source: European standard EN 1473

In any type of tank, the one hazard most often mentioned in connection with the storage of LNG is a phenomena known as "roll over.' Rollover refers to the convection or motion of fluid which occurs when liquids of different densities exist in a storage tank. If different densities or stratification do occur within a tank such that a denser and warmer liquid is at the bottom of the tank and subject to heat leak, that liquid can ultimately become heated to the point that it is less dense than the liquid above it, and it will be rapidly moved by buoyant forces up the tank side walls to the surface. At this point, it experiences a sudden decrease in pressure and being above its normal boiling point vaporizes very rapidly in large quantities causing a significant pressure rise in the tank. As a result of this rapid expansion, cracks or even tank rupture can occur. Peak shaving plants have a greater potential for rollover due to weathering of the LNG and/or introduction of new LNG into a partially filled tank.

However, industry research on rollover has been extensive, resulting in deliberate controlled mixing of the tank contents, selected top, side, or bottom filling, careful monitoring of the temperature of the LNG contents throughout the tank, higher design tank pressures combined with low normal operating pressures, and improved venting. In addition, the potential of the phenomena occurring at a base-load plant is further reduced by an operational practice of unloading tankers into empty tanks, not partially filled tanks as can occur at peak-shaving plants.

4.2.3 Re-gasification and vaporizer

From the storage tanks, LNG is pumped to the Re-gasification plant where it is vaporized by heating it. Frequently, the LNG is heated in systems using the naturally occurring heat in nearby seawater. Other systems use process heat from other equipment or have heat ex-changers fueled with oil, electricity, gas, or ambient air. None of the vaporizer systems is obviously the most economical or technically superior. The choice depends primarily on the location and design of a specific terminal and operating regulations.

a) Vaporization capacity and options

The send-out pumps and vaporizers must meet the maximum contractual send-out rate. It is common practice to have at least one spare unit for reliability and maintenance functions.

Various commercially proven methods are available for LNG vaporization. These include open rack vaporizer (ORV), submerged combustion vaporizer (SCV), and shell-and-tube heat exchange.

The ORV uses seawater as the heat source to vaporize the LNG. An ORV consists of two horizontal headers connected by a series of vertical tubes. LNG enters the bottom header and moves up through the vertical tubes. Seawater is either sprayed or cascaded on the vertical tubes. Vaporized gas is collected and removed from the top header. In an SCV, the LNG is vaporized in a bath of hot water, which is indirectly heated by combusting natural gas. The maximum water bath temperature is approximately 40 °C.

SCV needs less capital cost than ORV, but operating costs are more expensive than ORV. Normally, ORV is used in base operation and SCV as peak shaving and spare equipment.

The shell-and-tube exchanger is suitable for LNG vaporization over a wide range of temperatures and pressures. Various heating mediums are employed as the heat source for vaporization. These include:

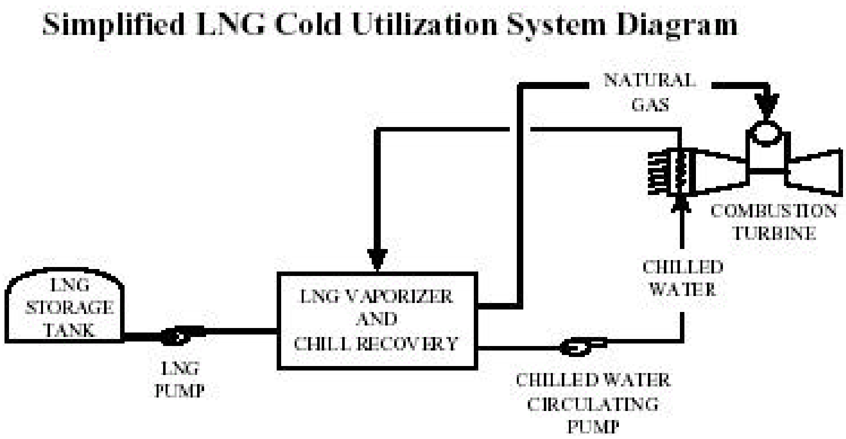
- Seawater
- Low pressure (LP) steam
- Closed loop glycol/water systems

High pressure vaporization is better option to vaporize LNG. In the high pressure vaporization, the LNG is pumped to the desired pressure and then vaporized. In another option that is referred to as low pressure vaporization, the LNG is vaporized and then compressed to the desired pressure. In his study Ram (1998) recommended high pressure vaporization option is preferred because of the better overall performance and lower capital cost.

b) LNG cold utilization options

A number of options are available for LNG cold utilization (Figure 4.1). The following is a brief description of some of the options that can be used to integrate LNG cold utilization into the operations of a power plant (Ram, 1998).

- Condenser Circulating Water Cooling
- Cryogenic Power Generation
- LNG-Assisted Air Liquefaction and Separation
- Gas Turbine Combustion Air Cooling



Source: Ram, 1998

Figure 4.1 Simplified LNG cold utilization system diagram

c) Capacity of send-out lines

The send-out pipelines must have the capacity to take away the maximum sendout rate consistent with maintaining the nominal throughput. Pipeline capacity can be increased by compressor stations and line looping, but these functions may not be within the control of the terminal operator. Moreover, the local and regional areas served by the terminal need to absorb the throughput.

4.2.4 New developments in LNG terminals

a) Unloading system

Bertrand (2001) pointed out that traditional unloading system presented several drawbacks that included:

- Proximity of the coast is necessary
- The site has to be sheltered
- The breasting dolphins have to be dimensioned so that one dolphin only has to absorb all the berthing energy of the ship
- A limited depth

Moreover, Iversen (1992) ever addressed that "the present state of the jetty/harbour facilities of the LNG terminals of the world represent the strongest restraint on the introduction of large LNG carriers.

New concepts of unloading system are introduced and developed. These jetties necessitate a very large number of piles and a lot of civil work, the cost of which becomes rapidly prohibitive when the distance to the cost increases. David, Haynes (2001) addressed that "the key to reducing jetty costs is therefore in the design of the trestle"; argued that LNG carrier can be unloaded using single point mooring (SPB); and introduced a trestle-less jetty with sub-sea LNG pipeline for cost reduction. Further, Bertrand, L. (2001) introduced a radically new concept of unloading system based on a rotating quay that not only allowed to be at some distance from the coast and the use of flexible hoses for gas transfer, but also could serve non dedicated ships and reduce the overall cost significantly.

b) Floating receiving terminal

A floating storage and Re-gasification unit (FSRU) has been developed after the successful completion of the AZURE R&D project (Marinelog, 2001). This shows that it is possible that some LNG ships can be fitted with facilities for the onboard Re-gasification of LNG. A ship with such facilities could deliver LNG without the need for an LNG receiving terminal. The ship would become floating storage with regasified LNG being delivered directly from the ship into the customer's pipeline system. Such a system could be a short-term measure to accelerate development of a market in advance of the construction of a receiving terminal. It might also be used on a long-term basis if the market size did not justify the construction of an LNG receiving terminal. However, it would require a ship to be moored for several days while its cargo is discharged and hence would be an inefficient use of shipping capacity, although it would preclude investment in receiving facilities. In addition, there would be an interruption in gas supply as the ship went to lift another cargo. Therefore, at least two ships would be required to provide an uninterrupted supply of gas to the market.

4.3 Re-gasification costs

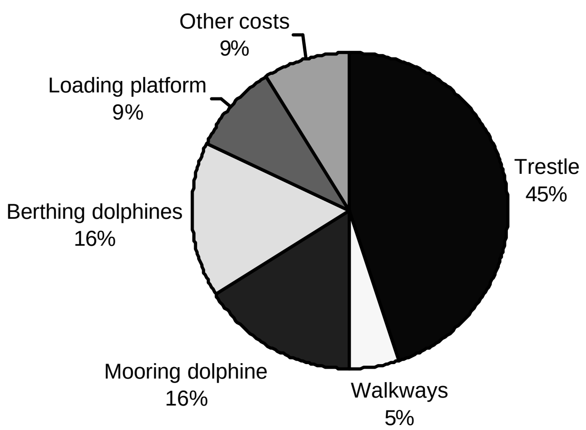
Re-gasification costs refer to costs incurred in imports terminal and vaporization, which can be divided into capital costs in Re-gasification facility and operating costs incurred in operation.

4.3.1 Capital costs

The costs for an LNG import terminal depend on several significant variables, which include:

- Storage capacity installed
- Geology of the area (soil stability and seismic activity)
- Labor and construction costs for the area
- Marine situations including proximity to deep water, need for dredging and/or breakwater, the trestle length

For example, the capital cost of a jetty ranges from 3.3 million US$ (Iversen, 1993, p8) to 4.2 million US$ (EIA, 2001, p33). David Haynes (2001) showed the cost of a typical jetty facility (Figure 4.2), excluding topsides.



Source: David, Haynes.

Figure 4.2 Cost breakdown for a traditional piled jetty

Moreover, Iversen (1993, p9) estimated that a unit cost of storage capacity was 580 US$ per cubic meter.

4.3.2 Operating costs

In addition to capital costs of a terminal, the main operating costs of the facility can be divided into fixed and variable costs. The fixed costs are payroll, maintenance, insurance, and taxes, which varied from place to place. Variable costs include fuel, electricity, chemicals, and other consumables. For example, EIA (2001) ever estimated that in U.S.A the base operating costs can be broken down as following:

- Payroll is estimated at $2.8 million per year for approximately 22 employees
- Maintenance costs account for an additional $2.8 million per year
- Taxes and insurance are estimated at $5.7 million
- Electricity consumption is estimated to be approximately 480 kilowatthours per day

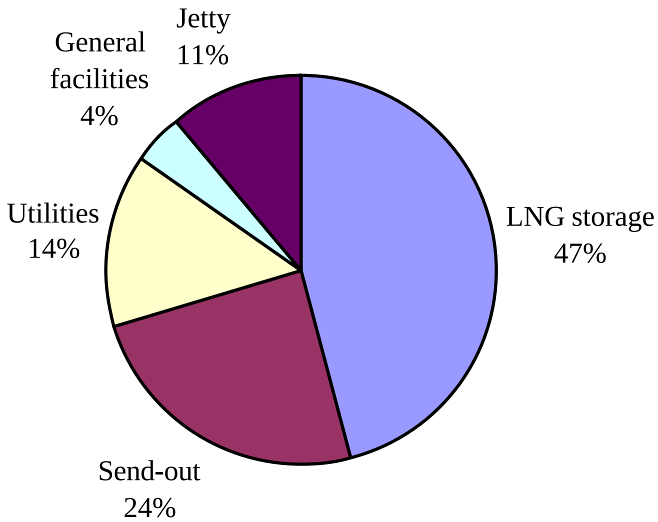
4.3.3 Cost structure of Re-gasification

Re-gasification costs are typically considerably lower than liquefaction plant costs (Table 4.2). Moreover, Re-gasification energy requirements consume a further 1.5-2.5 percent of the delivered LNG (CERA, 2002).

Table 4.2 Investment of some LNG terminals

Country	Terminal's name	Type	Capacity	Year of start up	Price (US$)	Observations
Angola		Liquefaction	3MTA	2007	1 billion	
Norway	Snovhit	Liquefaction	3MTA	2006	2.8 billion	
Oman		Liquefaction	2x3.3MTA	2001	2.5 billion	
Spain	Regasona	Regas	2.5bcbm	2004	€230 millions	Possible extension to 5bcbm
China	Guangdong LNG project	Regas	3MTA	2005	870 millions	Including 509km of pipe distribution
Portugal	Sines	Regas	2.4*10^9 cbm/year	2006	N.A	Ext; to 4.8 by 2010

Source: GTT, values gathered by Mr. Yatagen in various specialized papers of the industry



Source: John

Figure 4.3 Receiving terminal cost breakdown

The main part of costs is storage costs because heavy capital cost in construction of storage tank. John (2001) estimated that cost of LNG storage accounts for 47% of the total receiving terminal cost. Figure4.3 shows cost structure of LNG receiving terminal. Moreover, Iversen (1993, p9) estimated that a unit cost of storage capacity was 580 US$ per cubic meter. The inflation factor is (Robert, 2002):

$$1 \text{ US\$ (1993)} = 1.225 \text{ US\$ (2001)}$$

Considering the inflation factor, the unit cost of storage capacity can be revised:

$$580 \times 1.225 = 710 \text{ US\$ (2001)}$$

Based on their study the relationship between capital cost of Re-gasification and ship size can be concluded at below table (Table 4.3).

The estimated results seems reliable comparing with the investment of Gongdong LNG project in China (see Appendix F).

Table 4.3 Relationship between capital cost of Re-gasification and ship size

Ship size (cubic meter)	125000	138000	147000	160000	200000
Necessar storage capacity (cubic meter)	250000	276000	294000	320000	400000
Unit cost of storage (US$ per cubic meter)	710	710	710	710	710
Capital cost of storage (million US$)	178	196	209	227	284
Percentage of total caiptal cost	47%	47%	47%	47%	47%
Total capital cost of receiving terminal (million US$)	378	417	444	483	604

Note: Source: based on research of Iversen (1993)

Summary

Nowadays, LNG terminals have become the main constraints against increase of ship capacity, introduction a bigger vessel to a new project must consider the terminal situations. Some new technologies have been developed in terminals.

Safety is the first priority in the design and operation of LNG imports terminal. Exclusive zones are needed. A typical ship unloading requires about a 24 hours turnaround time.

The main facilities in a LNG terminal consist of jetties, storage tanks and vaporizers. The capacities of the storage tank are roughly equivalent to twice of size of a single LNG ship because the ship storage cost is about 5 or 6 times of the onshore storage cost, and flexibility requirements.

As to re-gasification costs, storage costs dominated the LNG re-gasification costs. Therefore, the re-gasification costs mainly are influenced by both imports volume and ship size

Chapter 5 Optimising LNG chains and a case study

Introduction

The fundamental objective for a successful LNG project is to select the best supply chain to meet market demand. It should be bear in mind that all those sectors in a LNG chain interactive each other and need to operate simultaneously in order to get the scale of economic not only from one sector but also from all parts. In fact it is found that these factors are difficult to match together, constraints or bottleneck always existed in LNG supply chains (Iversen, 1993), which resulted in overcapacity of some sectors and total costs increase.

Total costs can be the criteria to evaluate and optimise LNG supply chains (Douglas, 1998, p469). There have been a lot of researches that tried to optimise the whole chain or only one part. For example, Packer (1993) focused his research in the one part: LNG shipping, and examined the extent of impacts on shipping costs resulted from ship size, service speed and financing. He found that better solutions for cost saving are to introduce larger LNG ships particularly for LNG projects with longer delivery distance and to use 20-21 knots service speed. However, in his research the relationships between shipping cost and total costs were not mentioned, and impacts on receiving terminal costs caused by changes of ship size were ignored. Iversen (1993) expended his research from shipping to the overall transportation costs. He agreed with Packer, and pointed out “larger and faster LNG carriers will give reduced costs of transportation”. Further, he estimated the related costs incurred by the terminal storage increase in an LNG project, and found “When including the costs of such additional storage we find that the differences between the use of ships of different sizes are reduced. Still the conclusion is valid, larger ships will offer reduced costs of transportation and storage.” In his report a function between capital cost of storage and ship size was described, but the total costs of LNG supply chains were not recognised. Recently, CERA (2002) did a valuable research to estimate total costs for LNG projects that covered the whole supply chain, and acceptable supply chains are recommended to imports countries, including China. However, ship size was fixed as 130,000 cubic meters, optimisation of these supply chains were not completed.

This chapter tries to optimise supply chains for an LNG imports project based on total cost analysis. In order to examine the research method and results, one case (Gongdong LNG project in China) is selected. Moreover, the factors in a LNG chain that have impacts on the total costs are also discussed.

5.1 Scenarios and procedure of calculation

5.1.1 Base case and scenarios

Guangdong LNG project will be the first LNG imports project in China as mentioned before. There will be two phases in this project. In phase 1 the scale of project will be 3 Mtpa and is estimated to be in operation in 2005 and Phase 2 is estimated to have a scale of 5 Mtpa (more details see Appendix F).

According to news of People’s Daily (23, Jan, 2002), there are three candidate states to attend bids and got qualification to supply gas: Australia, Indonesia and Qatar. The project will be conducted in terms of FOB contract and “under current plans, the China Ocean Shipping Company will carry out transportation activities jointly with foreign partners” (Poten, 2002).

Based on these information, two scenarios are given in this case study.

- Scenario 1: To import 3 million tons of LNG per annum (Mtpa)
- Scenario 2: 5 Mtpa

The aim to set two scenarios is to compare the impacts on total cost and optimization resulted from imports volume. Through two scenarios differences can be found in optimizing LNG chains and relationship between total cost and imports volume can be reflected.

5.1.2 Procedure of optimizing

Total costs in a supply chain include three components: FOB supply costs (including gas feed costs, liquefaction and export costs), shipping costs and re-gasification costs. Based on the concept of total costs, the optimizing procedures include:

- To identify objectives and Scenarios. The aim is to find the best LNG supply chain with minimum total costs.
- Assumptions to make the calculations simple and meaningful.
- Identify LNG supply chains. To estimate sea transport distance and voyage days, to get the FOB supply costs of these potential gas suppliers.
- Calculations shipping costs and re-gasification costs based on IRR discounting methods.
- To get the total costs and compare the results.
- To find the best supply chain.
- To examine the results.

5.2 Cost calculation and assumptions

5.2.1 Main assumptions

In order to conduct calculations and optimizing, the main assumptions include:

- Gas is traded on FOB basis
- The gases are only supplied by one gas resource who comes from either Australia, Indonesia or Qatar
- The gas qualities are assumed same (see Appendix A)
- To each supply chain only one type of LNG carrier is chartered by buyer in form of time charter
- Only five types of ship are available in chartering market: 125,000, 138,000, 147,000, 160,000 and 200,000 cubic meters
- The capacity of LNG fleets can meet the demands for the project
- The capacity of storage tank in receiving terminal is two times of ship size

5.2.2 FOB supply costs

FOB costs refer to liquefaction and exports costs. As mentioned before, the costs varied according to gas resource. In this study there are there alternative gas resource to support Chain LNG project: Australia, Indonesia and Qatar.

FOB cost are given in this case study based on research results of CERA (2002). The distances between Shenzhen of China and these places are listed in Table 5.1.

Table 5.1 Information and FOB costs of gas resources

Country	Indonesia	Australia	Qatar
Project	Tangguh	Northwest Shelf	RasGas/QatarGas
Estimated FOB LNG Costs (US$/MMBtu)	1.80	1.35	1.25
Distance to China (miles)	1,900	2,773	5,068
Sea transport days	8.2	10.9	19.9
Round voyage days	11.2	13.9	22.9

The calculations of sea transport days are based on “Veson distance table calculation (2000)” developed by Fairplay Ltd. Assumptions are:

- The service speed of all the ships is 19.5 knots (22.5 miles) per hour
- Time in ports: 1 day at each port and 2 days totally
- Waiting time for one round voyage: 1 day totally

Table 5.2 Ship number needed

Gas resource		Indonesia	Australia	Qatar	Indonesia	Australia	Qatar
Ship size	125000	2	2	4	3	4	6
	138000	2	2	3	3	3	6
	147000	2	2	3	3	3	5
	160000	2	2	3	2	3	5
	200000	1	2	2	2	2	4

5.2.3 Shipping costs

Shipping costs consist of capital cost, operating cost and voyage cost. Here assuming buyer charter LNG carrier in form of time charter, and there are three types of fleet for chartering: 138,000, 160,000 and 200,000 cubic meters carrier. Currently 138,000 cubic meters is the popular size of LNGC, and 160,000 and 200,000 cubic meters fleet were thought available in technical side and world emerge in the future by Iversen (1993), Packer (1993) and other researchers. Table 5.2 lists the number of ships needed each shipping route.

a) Time charter costs

Time charter costs of LNGC are estimated and showed in Table 3.2, and assumptions are showed in Table 3.3. As explained in Chapter 3, those calculations are conducted based on IRR discount analysis and by the program developed by Drewry Consulting (1996). The details about calculation of time charter rate refer to Appendix G.

b) Voyage costs

Voyage costs include boil off cost, bunker cost and port cost, which is also determined by voyage distance and ship speed etc. Table 5.3 shows voyage costs between different gas resources, details of calculations refer to Appendix G.

Table 5.3   Ship voyage costs (US$ per round voyage)

Ship size (m^3)	Gas resource		
	Indonesia	Australia	Qatar
125000	395430	457007	662263
138000	412094	477688	696335
147000	423630	492006	719923
160000	440294	512687	753995
200000	491568	576321	858831

In term of value of boil-off gas (BOG), both Hamilton (1996) and Mokrane (2002) pointed out that the assumption of value of the BOG is “indeed arguable” because values ranging from zero to CIF price have been considered by players in the gas industry. The author agrees to value boil-off gas as CIF price because it represents a direct loss of cargo to be sold. Therefore, the BOG value is assumed 3.5 US$/MMBtu, the acceptable CIF price in South China (CERA). Other assumptions include:

- Receiving port is Port of Shenzhen
- Average bunker cost is 8,500 US$ per voyage day after boil off
- Sea margin is 5%

c) Shipping costs

Shipping costs are estimated based on estimated time charter costs and voyage costs and showed in Table 5.8.

5.2.4 Re-gasification costs

Re-gasification costs refer to terminal costs and vaporizing costs. Normally re-gasification costs is a function of import volume (gas demand) and ship size. Capital costs of receiving terminal increase as increase of ship size. This point is line with what Hamilton (1996) addressed "It is recognized that larger ships require larger jetties and an increase in storage capacity at the production plant end."

Table 5.4 Estimated re-gasification costs

Ship size (cubic meter)		125000	138000	147000	160000	200000
Full Regas Cost (in US$ per MMBtu Output)	Scenario 1	0.51	0.57	0.60	0.66	0.82
	Scenario 2	0.31	0.34	0.36	0.39	0.49

Table 5.5 LNG re-gasification costs assumptions

Construction period (years)	3
Conversion Loss	2.5% of input gas
Operating and maintaining costs	3.0% facilities investment
Leverage	70%
Debt Term (years)	10
Interest Rate	8%
Depreciable Life (years)	20
Target IRR (on equity)	15%
Conversion Loss	2.5% of input gas
Working days per year	365

The capital costs of the LNG terminals have been estimated and shown in Table 4.3.The re-gasification costs are estimated based on IRR discounting method and Table 5.4 shows the estimated value under each scenario. Table 5.4 lists the main assumptions. The details of calculations refer to Appendix G.

Comparing with research of CERA (2002) the estimated re-gasification costs are believed acceptable. Other assumptions are showed at Table 5.5.

5.3 Results of estimation

Based on above assumptions and calculations, the total unit costs of LNG chains are estimated and given in Table 5.6 and Table 5.7 for Scenario 1 and Scenario 2 respectively.

Table 5.6 Total unit costs of LNG chains under Scenario 1

(US$ per MMBtu)

Gas resource	Indonesia					Australia					Qatar				
Ship size (cubic meters)	125,000	138,000	147,000	160,000	200,000	125,000	138,000	147,000	160,000	200,000	125,000	138,000	147,000	160,000	200,000
FOB supply costs	1.8	1.8	1.8	1.8	1.8	1.35	1.35	1.35	1.35	1.35	1.25	1.25	1.25	1.25	1.25
Shipping costs	0.47	0.48	0.49	0.50	0.33	0.49	0.50	0.51	0.52	0.56	0.89	0.75	0.76	0.79	0.63
Re-gasification costs	0.51	0.57	0.60	0.66	0.82	0.51	0.57	0.60	0.66	0.82	0.51	0.57	0.60	0.66	0.82
Total unit cost	**2.78**	**2.85**	**2.89**	**2.95**	**2.95**	**2.35***	**2.41**	**2.46**	**2.53**	**2.73**	**2.66**	**2.57**	**2.62**	**2.69**	**2.70**

*Note: *- the minimum total unit costs.*

Table 5.7 Total unit costs of LNG chains under Scenario 2

(US$ per MMBtu)

Gas resource	Indonesia					Australia					Qatar				
Ship size (cubic meter)	125,000	138,000	147,000	160,000	200,000	125,000	138,000	147,000	160,000	200,000	125,000	138,000	147,000	160,000	200,000
FOB supply costs	1.8	1.8	1.8	1.8	1.8	1.35	1.35	1.35	1.35	1.35	1.25	1.25	1.25	1.25	1.25
Shipping costs	0.44	0.45	0.45	0.35	0.37	0.56	0.47	0.48	0.49	0.39	0.83	0.86	0.77	0.78	0.72
Re-gasification costs	0.31	0.34	0.36	0.39	0.49	0.31	0.34	0.36	0.39	0.49	0.31	0.34	0.36	0.39	0.49
Total unit cost	**2.55**	**2.59**	**2.61**	**2.55**	**2.66**	**2.21**	**2.16***	**2.19**	**2.23**	**2.23**	**2.39**	**2.45**	**2.38**	**2.43**	**2.46**

*Note: *-the minimum total unit costs*

5.4 Findings

Based on estimated results there are some findings. These findings are listed sequentially according to the scenarios, then the integrated findings are addressed.

5.4.1 Scenario 1 - 3 Mtpa

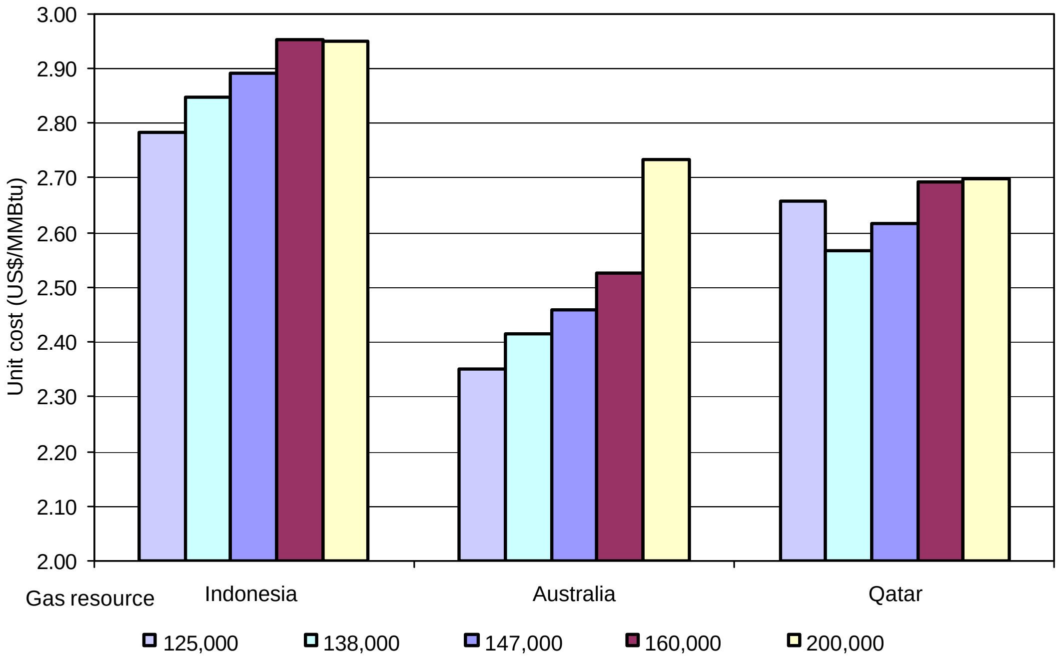


Figure 5.1 Total costs of LNG supply chains – Scenario 1

In Figure 5.1 it is found:

- The total costs of all supply chains are less than market price of natural gas (3.5 US$/MMBtu), which means that all supply chains are acceptable.
- The minimum total unit costs of LNG chains is 2.35 US$/MMBtu.
- Therefore, the optimal LNG supply chain is:

  Importing LNG from Australia by 125,000 m^3 LNG tanker, the corresponding capacities of storage in receiving terminal at least are 250,000 m^3.

Figure 5.2 shows the cost structure of LNG supply chains from Australia to China. It is observed that shipping costs and re-gasification costs increase as the ship size increase. Moreover, the increase of re-gasification costs indicates the offset of larger vessels. This means that larger ships do not have any advantages in this supply chain.

The utilization ratios of ship capacities decrease as bigger ships are introduced in the route Australia-China (Table 5.8 and Figure 5.2), which indicates that shipping capacities are beyond the demand when bigger ships are chartered and more costs are incurred. This finding also corresponds to the flexibilities of LNGC and can explain why 125,000-138,000 m^3 LNG tank become popular in market today.

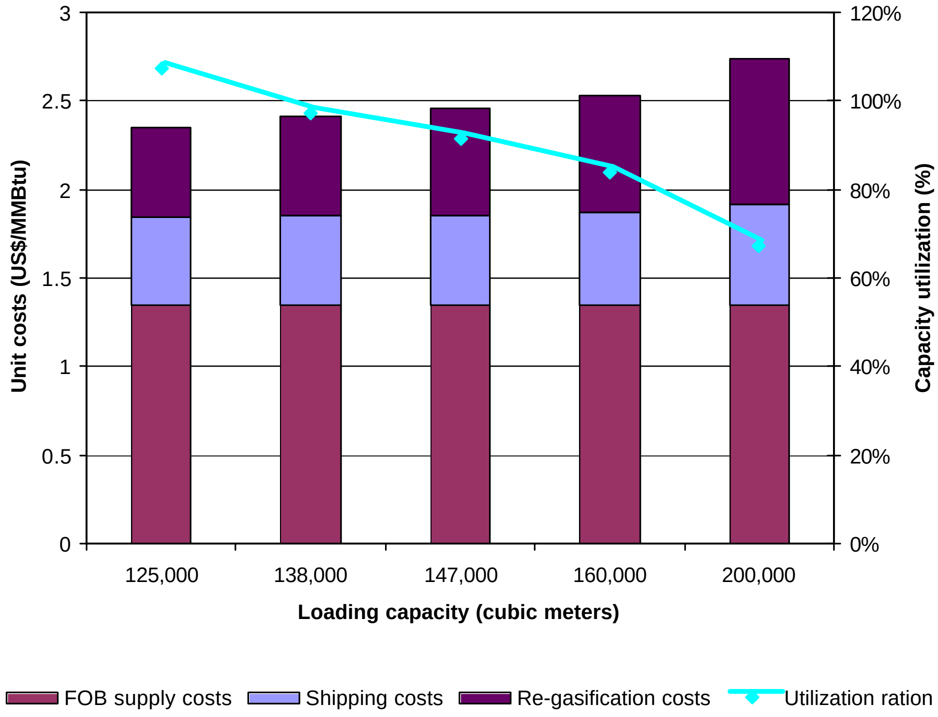


Figure 5.2 Breakdown of total costs in LNG chains (Australia-China)

Table 5.8 Utilization of ship capacities (Australia-China)

Ship size (m^3)	Numbers needed	Numbers chartered	Utilization ratio (%)
125000	2.1	2	**107%**
138000	1.9	2	**97%**
147000	1.8	2	**91%**
160000	1.7	2	**84%**
200000	1.3	2	**67%**

Note: ration that is larger than 100% means the delivery capacities are less than gas imports volume

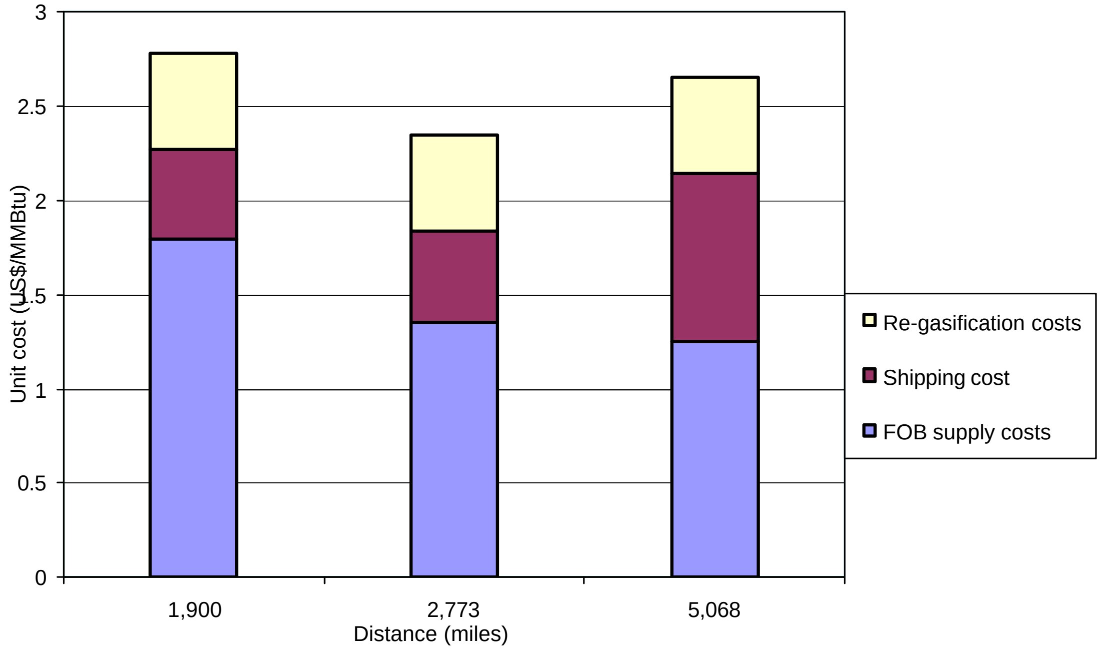


Figure 5.3 Relationship between total costs and distance (125,000 m^3 LNGC)

Figure 5.3 shows how the total costs are influenced by gas resources, even the chain is carried out by the same LNG tanker. It is observed that FOB supply costs account for more than half of the total costs in three gas resources. Findings are:

- The proportion of the FOB supply costs indicates that gas resource play a key role in a LNG supply chain.

- Cost structure varied when gas resources are changed. When distances increase, the shipping cost accordingly increase because more ships need to be chartered, the tradeoff comes from the cheaper natural gas. This figure shows how the elements of a LNG chain interact and why optimization is necessary.

5.4.2 Scenario 2 - 5 MTPA

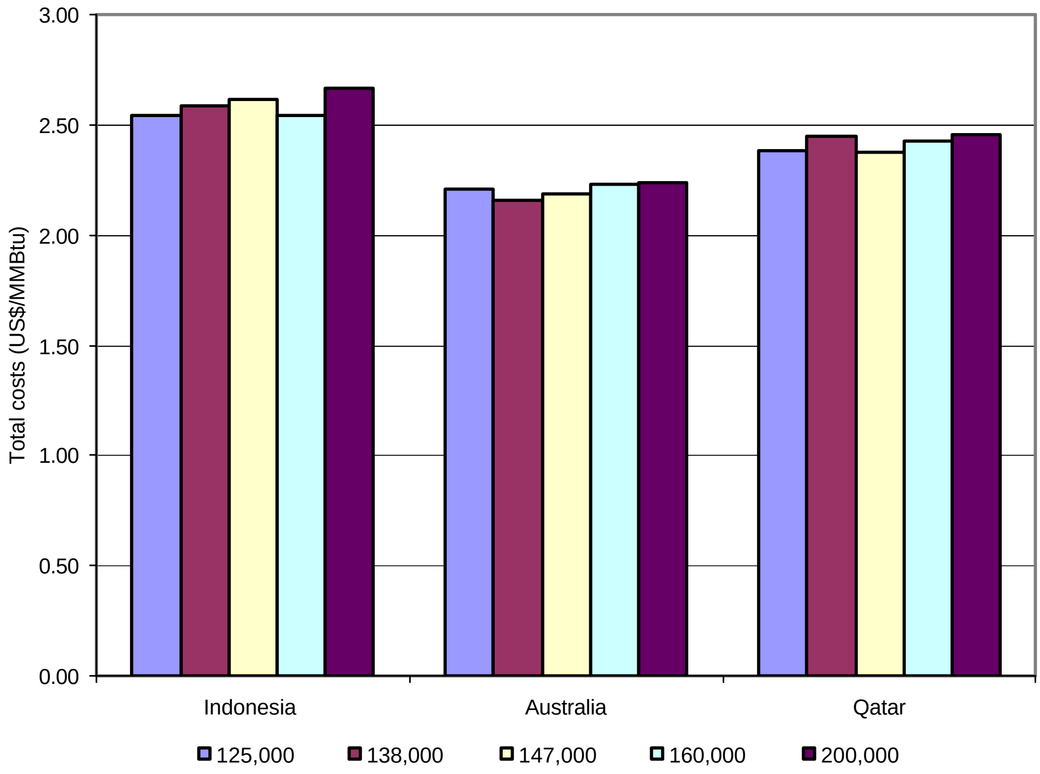


Figure 5.4 Total costs of LNG supply chains – Scenario 2

Findings in Figure 5.4 are:

- The total costs of all supply chains are less than market price of natural gas (3.5 US$/MMBtu), which means that all supply chains are acceptable.
- The minimum total unit costs of LNG chains is 2.16 US$/MMBtu.
- Therefore, the optimal LNG supply chain is:

  Importing LNG from Australia by 138,000 m^3 LNG tanker, the corresponding storage capacities in receiving terminal at least are 276,000 m^3.

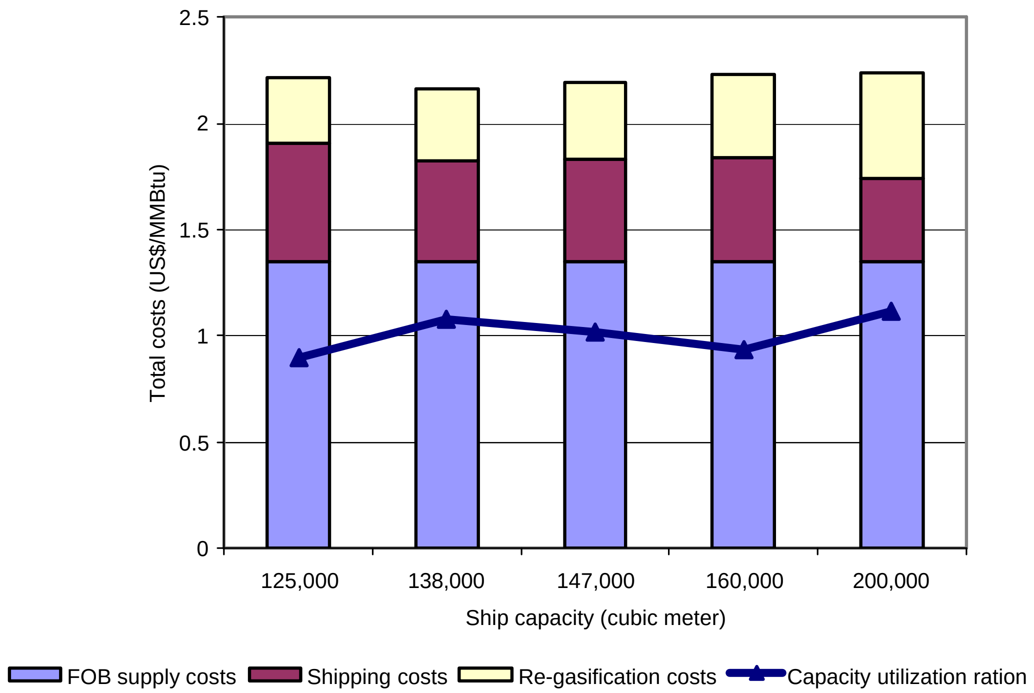


Figure 5.5 Breakdown of total costs in LNG chains (Australia-China)

Figure 5.5 shows cost structure of LNG chains from Australia to China, which is carried out by different type of ships. The findings that are observed in this figure include:

- The larger LNGC has advantage in shipping. The minimum shipping costs come from 200,000 m^3 LNGC. The reason is more ships are needed for smaller ship so as to increase capital costs. For example, 4 vessels needed for 125,000 m^3, only 2 tanks for 200,000 m^3. As to the other three types, the shipping costs are almost the same.
- The cost saving of 200,000 m^3 LNGC in shipping are offset by the increase of re-gasification costs, therefore, the minimum total costs come from 138,000 m3 LNGC

Table 5.9 Utilization of ship capacities under Scenario 2 (Australia-China)

Ship size (m^3)	Numbers needed	Numbers chartered	Utilization ratio (%)
125000	3.6	4	90%
138000	3.2	3	108%
147000	3.0	3	102%
160000	2.8	3	93%
200000	2.2	2	112%

Note: ration that is larger than 100% means the delivery capacities are less than gas imports volume

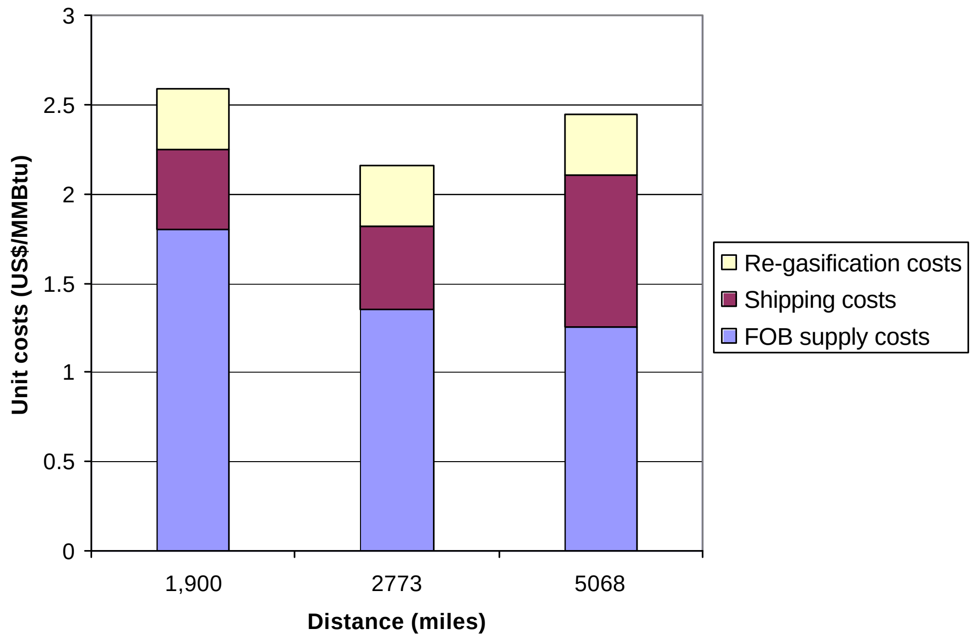


Figure 5.6 Relationship between total costs and distance (138,000 m^3 LNGC)

Figure 5.6 is similar to Figure 5.3, which indicates the cost structure of LNG chains are similar in spite of changes in transport volume. The findings are similar to Scenario 1 too.

5.4.3 General findings

Figure 5.7 combines the total costs of all the LNG supply chains with two scenarios, and shows 10 alternative solutions. Figure 5.8 shows the relationships between LNGC capacities and re-gasification costs. Moreover, Table 5.10 presents 6 optimal ship capacities with each shipping route.

Comparing with two scenarios based on the figures and table, the findings are:

- Economy of scale. In Figure 5.7 it is found that all curves that stand for total costs of 5 MTPA project are below all those curves that represent total cost of 3 MTPA project. This indicates that all the total costs in Scenario 2 are less than Scenario1 because of the economy of scale.
- Ship capacity. From Table 5.10 it is observed that optimal ship capacities increase as the imports volume up, this trend not only occurs in route of Austria-China, but also emerges in other both routes. This finding points that larger LNGC has more competitive advantage as transport volume increase.

- Large vessels and offset. Figure 5.7 also shows that total costs that are carried out by the largest tanks are the highest among all those options in both scenarios. The reason is that larger ships require larger jetties and bigger storage capacities. These additional investments offset the advantages of large vessels. This point is clearly supported in Figure 5.8: as ship size increase, both curves move up.
- Therefore, the economy of larger ships is offset by more capital costs in the terminals. These findings are similar to what Hamilton (1996) addressed:

  > The use of larger ships in a project is not seen as a technical issue either. The issue is one of persuading the market to accept larger ships and for various elements in the supply chain to accept that the size of ship can affect cost of transportation.

- It is necessary to observe all the sectors in a LNG chain and to evaluate the advantages and disadvantages in the process of optimizing.

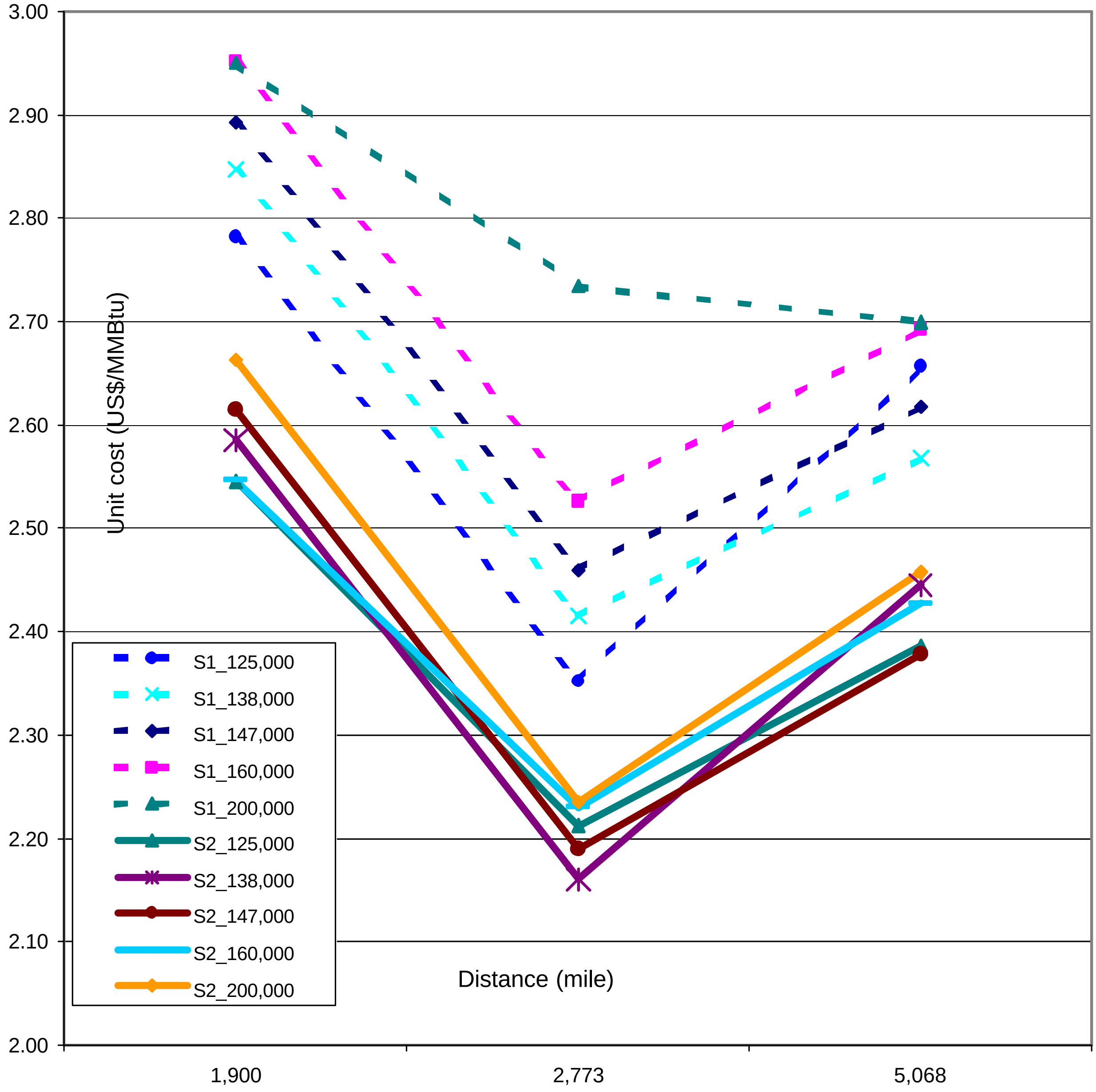


Figure 5.7 Comparison total costs under two scenarios

Table 5.10 The optimal ship capacity with routes

(cubic meters)

Routes	Distance (miles)	Scenario 1	Scenario 2
Indonesia-China	1,900	**125,000**	**125,000/160,000**
Australia-China	2,773	**125,000**	**138,000**
Qatar-China	5,068	**138,000**	**147,000**

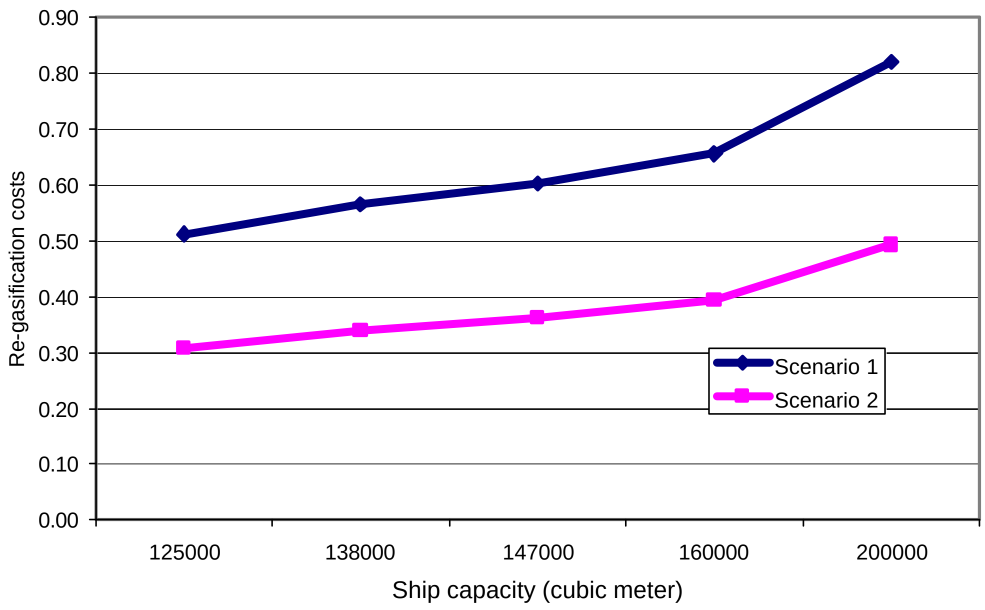


Figure 5.8 Relationship between re-gasification costs and ship capacity

Summary

In this chapter the case study of optimizing LNG supply chains in China is completed. The key issues include:

- Optimizing procedures are identified and the two scenarios of the case are given.
- Total costs of LNG chains are calculated and evaluated.
- It is observed that all LNG chains are acceptable.
- However, the optimal LNG chains are:

- Scenario 1: Importing LNG from Australia by 125,000 m^3 LNG tanker, the corresponding receiving storage capacities at least are 250,000 m^3
Scenario 2: Importing LNG from Australia by 138,000 m3 LNG tanker, the corresponding receiving storage capacities at least are 276,000 m3

Conclusions and recommendations

1. Conclusions of the study

From the preceding chapters it can be concluded that:

- The demand for natural gas is growing rapidly as a clean energy with environmental concerns, energy security and diversification in China; the consumption is expected to more than triple by 2010 and to be 11% of energy consumption in 2020.
- The deficits of natural gas are expected to be about 20 billion cubic meters per year in 2010 and 65.0 billion cubic meters per year by 2020, which make it compulsory to import natural gas.
- Therefore, the Chinese government has launched 3 LNG projects in Southeast China, where are the most developed coastal areas: Guangdong LNG project that will operate in 2005; and two other projects located in Fujin province and Shanghai that are in pilot plan.
- However, Developing an LNG project and create an LNG chain is a high capital consuming activity of about 4-8 billion US$. Therefore, buyer and seller are bound by a long-term take-or-pay contract for each project. Now the situations are changing: the short term LNG trading are increasing; about 60% of LNG contracts that were signed since 1995 are on FOB because buyer want to control ships.
- Through the cost structure of the LNG supply chain varies from project to project, it can be estimated that FOB supply costs account for about half of the total cost, which indicates gas resource plays a key role in selecting a LNG chain.
- As to the shipping systems design in an LNG chain, there is no definitive answer as to which one is better; it depends on the project preference and cost sensitivity. Nowadays, all the vessels on order have capacities between 135,000 and 145,000 cubic meters. Indeed there is no practical reason to increase ship size to 200,000 m^3; however, up to now no port worldwide is equipped to berth and handle such large vessels.
- Shipbuilding price varies according to ship capacity. An LNG tanker typically cost 165 million US$, which costs high because of the complexity of LNG tanker. The

building prices declined sharply during 1990s mainly due to high competitions between shipyards but even stand high anyway.

- At last, the storage cost represents about 50% of the total LNG terminal investment.
- To evaluate the best alternative supply chains for LNG imports in China, the author has used the following methodologies:
- Total cost analysis has been conducted to optimise LNG supply chains, which minimize overall logistics costs, rather than attempt to minimize the cost of individual activities. Therefore, 2 scenarios are selected to evaluate the alternative solutions:
  - Scenario 1 is a LNG project with capacity of 3 MTPA
  - Scenario 2 is a 5 MTPA project
  - For each scenario, 3 gas resources are given: Australia, Indonesia and Qatar; 5 types of ship are proposed: 125,000, 138,000, 147,000, 160,000 and 200,000 cubic meters
- From the analysis, it concludes that:
  - **For a 3MTPA LNG imports project, the best supply chain is to import natural gas from Australia by 125,000m^3 ship, at least with 250,000 m^3 storage capacities in the receiving terminal.**
  - **For an LNG imports project of 5 MTPA, the best supply chain is to import gas from Australia by 138,000 m^3 ship, at least with 276,000 m^3 storage capacities in the receiving terminal.**

These results can be realistic since it was reported some days ago that Australia won the bid and would become the sole supplier of gas for the first LNG project in China (CNN). This news corresponded to the conclusion of this research.

2. Recommendations for further research

This research applied to the case study of China has tried to provide a concept and method that can be referred to other LNG projects. However, the limitations exist in this research and further research can be conducted with the availabilities of time and data.

2.1 Limits of this investigation

In this study, data mainly came from literature reviews due to confidentialities of data and limit of time though data were estimated by experience with the help of experts or authoritative reports.

Gas resources

In this study the natural gases that come from the three gas resources are assumed to be the same quality.

FOB supply costs

These data are quoted from CERA research results, and further details about cost structure need to be collected.

Ship costs.

Shipbuilding prices vary according to capacities and types, the one used in this research represents only the present situation.

Marine situations.

In this study it is assumed that all the ship sizes can be accommodated in loading and unloading ports and no additional costs for that.

Re-gasification terminal.

Unit cost of storage tank and the proportion of terminal cost structure are assumed to keep the same.

2.2 Future research fields

In this case study the numbers of options are definite as the number of gas resources and ship capacity are assumed to be certain. The optimisation programme that are employed in this research are conducted based on Excel sheet and has been proved reliable.

However, if the number of gas resources increase and ship capacities are not certain, the optimisation will be more complicated, and the linear programming (LP) methods could be more useful.

Therefore, the author has created, in collaborations with Professor Imai from the WMU, a mathematical model (see Appendix E) that generalizes the process of optimising LNG supply chains and can be used to resolve more complicated problems.

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Appendix A Table of gas conversion factors

CONVERSION FACTORS

Natural gas physical conversion factors

Equals	Million BTU	Bbls of Oil Equiv.	Tons of Oil Equiv.	Cu.ft Gas	Cu.m Gas	Cu.m LNG	Tons LNG (SG=0.425)	Tons LNG (SG=0.475)
1 Million BTU	1	0.172	0.0235	1,000	28.3	0.0459	0.0195	0.0218
1 Bbl of Oil Equivalent	5.80	1	0.136	5,800	164.2	0.266	0.113	0.126
1 Ton of oil equiv.	42.5	7.33	1	42.5	1,200	1.95	0.828	0.925
1 Cu.ft Gas	0.001	0.000172	0.0000235	1	0.0283	0.0000458	0.0000195	0.0000218
1 Cu.m Gas	0.0353	0.000608	0.000830	35.3	1	0.00162	0.0000688	0.000796
1 Cu.m LNG	21.8	3.76	0.513	21,824	618	1	0.425	0.475
1 Ton LNG (SG = 0.425)	51.3	8.85	1.207	51,350	1,450	2.353	1	-
1 Ton LNG (SG = 0.475)	45.9	7.91	1.081	45,950	1,300	2.105	-	1

NOTES:
Basic Cubic Metre = 35.315 Cu.ft
Gas Liquid Ratio = 618.1
Natural Gas at 1,000 Btu/Cu.ft (1m Btu = 1,000 Cu.ft)
Specific Gravity (SG) of LNG at 0.425/0.475

Natural gas conversion factors: rates of flow

Equals	100m Cu.ft/ Day Gas	M Cu.m/ Day Gas	Bn Cu.ft/ Year* Gas	M Cu.m/ Year* Gas	M Cu.m/ Year* LNG	SG = 0.425 Million Tons LNG per Year*	SG = 0.425 Million Tons Oil Equiv. p.a.	SG = 0.475 Million Tons LNG p.a.*	SG = 0.475 Million Tons Oil Equiv. p.a.*
100m cu.ft/day Gas	1	2.83	36.5	1030	1.67	0.711	0.858	0.795	0.858
1m cu.m/day Gas	0.353	1	12.9	365	0.591	0.251	0.303	0.281	0.303
1bn cu.ft/year* Gas	0.0274	0.0776	1	28.3	0.0458	0.0195	0.0235	0.0218	0.0235
1m cu.m/year* Gas	0.000968	0.00274	0.0353	1	0.00162	0.000688	0.00083	0.000769	0.00083
1m cu.m/year* LNG	0.598	1.69	21.8	618	1	0.425	0.513	0.475	0.513
SG = 0.425									
1m tpa* LNG	1.41	3.98	51.3	1450	2353	1	1.207		
SG = 0.425									
1m tons oil equiv. p.a	1.17	3.3	42.6	1,200	1.95	0.828	1		
SG = 0.475									
1m tpa* LNG	1.26	3.56	45.9	1,300	2,105			1	1,081
SG = 0.425									
1m tons oil equiv. p.a*	1.17	3.3	42.6	1,200	1.95			0.925	1

NOTES:
SG = Specific Gravity.
* Assumes 365 days per annum.

Appendix B-1 Non-pipeline gas transport technologies

Some reports pointed that economic transport distance between pipeline and LNG shipping varied according to volume delivered. Competitive advantages of pipeline falls in increasing volumes and that of LNG are in distance (Gi, Kyoung,). For example, given volume delivered of natural gas is 10 and 20 billion cubic meters, economic distance for pipeline is 3,200 and 5,600 kilometers respectively, which means beyond this distance LNG transport is more economy.

Natural gas reserves that would be extremely expensive to transport through pipelines to potential markets are commonly referred to as “stranded reserves.” It has been estimated that stranded reserves make up about 50 percent of the natural gas reserves held by the top 10 countries and between 2,755 and 3,350 trillion cubic feet worldwide (ZDC, 2001). Stranded reserves are expected to be a major source of natural gas for world LNG trade.

According to the research of Norwegian University of Science and Technology (Gudmundsson, 2001), there exited some other non-pipeline technologies for gas transport, especially for stranded gas fields. These technology include:

- Hydrate technology which concerns the making, moving and melting of natural gas hydrate (NGH) that contain 150-180 Sm^3 of natural gas per m^3 of solid, depending on the pressure and temperature of production. Feasibility studies show that hydrate technology for large-scale and long-distance transport of natural gas will cost about one-quarter less than established liquefied natural gas technology.
- Compressed natural gas (CNG) technology is widely used to store energy in cars and buses. Such small-scale use of CNG is expanding world-wide.
- Gas-to-Liquids (GTL) technologies are used to convert natural gas to hydrocarbon liquids. Several GTL technologies and projects existed and are being developed that have been presented by Knott (1997), Skrebowski (1998) and Thomas (1998).
- In addition, a full floating LNG chain technology has been developed by a French project. This LNG chain is based upon a permanently-moored Floating Production Storage and Offloading (FPSO) barge containing gas treatment, liquefaction and utilities units that is designed to receive, process and liquefy natural gas and to store and export the LNG, LPG and condensates. An offshore LNG transfer system to LNG shuttle carriers is therefore needed. On the other side the LNG carrier feeds the steel

Floating Storage and Regasification Unit (FSRU) which receives, stores, vaporises and exports to an onshore gas distribution grid. (see Figure B5.)

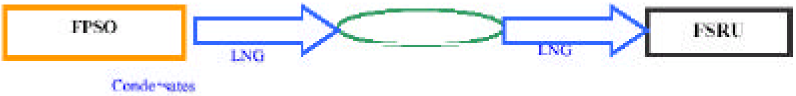


Figure B1 A floating LNG supply chain

- In addition to the above technologies, Gas-to-Wire (GTW) can be used to transport stranded gas to market. In GTW technology the natural gas is used to generate electric power at the site where natural gas is available, and then transported by cable (direct current) or wire (alternating current) to market.

Diagrams to illustrate the relationship between economic transport distance and different technologies, such as CNG, GTL, LNG and NGH have been presented by some researchers, who included Vareide (2000), BG Group (Fitzgerald and Martin 2000) etc. Here the capacity-distance diagram conducted by Gudmundsson and Mork (2001) for the transport of stranded natural gas is shown in Figure 1.1. The diagram illustrates what stranded gas technologies may be appropriated with respect to distance and capacity.

- LNG is generally considered appropriate for large-volumes for long-distances
- GTL is generally considered appropriate for medium-to-low volumes for long-distances
- Offshore pipelines in Norway are less than 1000 km in length are generally considered appropriate for large-volumes, for example above 1 BCM
- CNG, GTW and NGH technologies are considered appropriate for medium-to-low volumes and medium-to-short distances
- An overlap region is shown in Figure 1.1, to reflect the wide range of conditions that affect the stranded gas technology selected for a particular application

The economics of transporting natural gas to demand centers currently depend on the market price, and the pricing of natural gas is not as straightforward as the pricing of oil. More than 50 percent of the world's oil consumption is traded internationally, whereas natural gas markets tend to be more regional in nature, and prices can vary considerably from country to country. In Asia and Europe, for example, LNG markets are strongly influenced by oil and oil product markets rather than by natural gas prices. As the use and trade of natural gas continue to grow, it is expected that pricing mechanisms will continue to evolve, facilitating international trade and paving the way for a global natural gas market.

Appendix B-2 Natural gas pipeline projects in China

The gas reserve base is spread across China's various regions, although major concentrations exist in several basin areas, including the Tarim (holding 21.9 percent of China's total gas reserves), Sichuan (19.4 percent), Ordos (11 percent), Junggar (3.2 percent), and offshore (20 percent) basins (see Figure 2.11).

Environmental concerns in China are prompting movement toward gas and away from coal and oil, and energy security concerns are promoting the development of domestic gas supplies and the expansion of China's gas infrastructure (Figure B2).

1. The main domestic pipeline projects include:

a) West-to-East Pipeline

In early 2001, China's State Council approved a huge $12 billion pipeline project to develop gas reserves in the remote western part of the country and move the gas east by pipeline to Shanghai and other Yangtze Delta cities.

b) Other Inland projects

- Changqing-Beijing Pipeline: 864 km
- Changqing-inner Mongolia pipiline: 471 km
- Sebei-Xining-Lanzhou pipeline: 935 km
- Sichuan-Wuhan pipeline: 1,600 km
- Xi'an-Weinan Pipeline

c) Offshore gas projects

- Sanya-Qionghai pipeline: 700 km

2. Imports natural gas pipeline projects which are in discussion include:

a) Sino-Russian gas pipeline

The proposed pipeline project would link the Russian natural gas grid in Siberia to China and possibly South Korea via a pipeline from the Kovykta gas fields near Irkutsk, which hold reserves of more than 50 Tcf. The cost of the project has been estimated at $12 billion, and a feasibility study is underway.

The pipeline would have a planned capacity of 2.9 billion cubic feet per day (Bcf/d), of which China would likely consume about 1.9 Bcf/d and South Korea 1 Bcf/d.

b) Asian transnational gas pipeline

- Western Siberia-Shangshan: 1865 km
- Kazakhstan – Shanshan:
- Turkmenistan – Shanshan: 2150 km

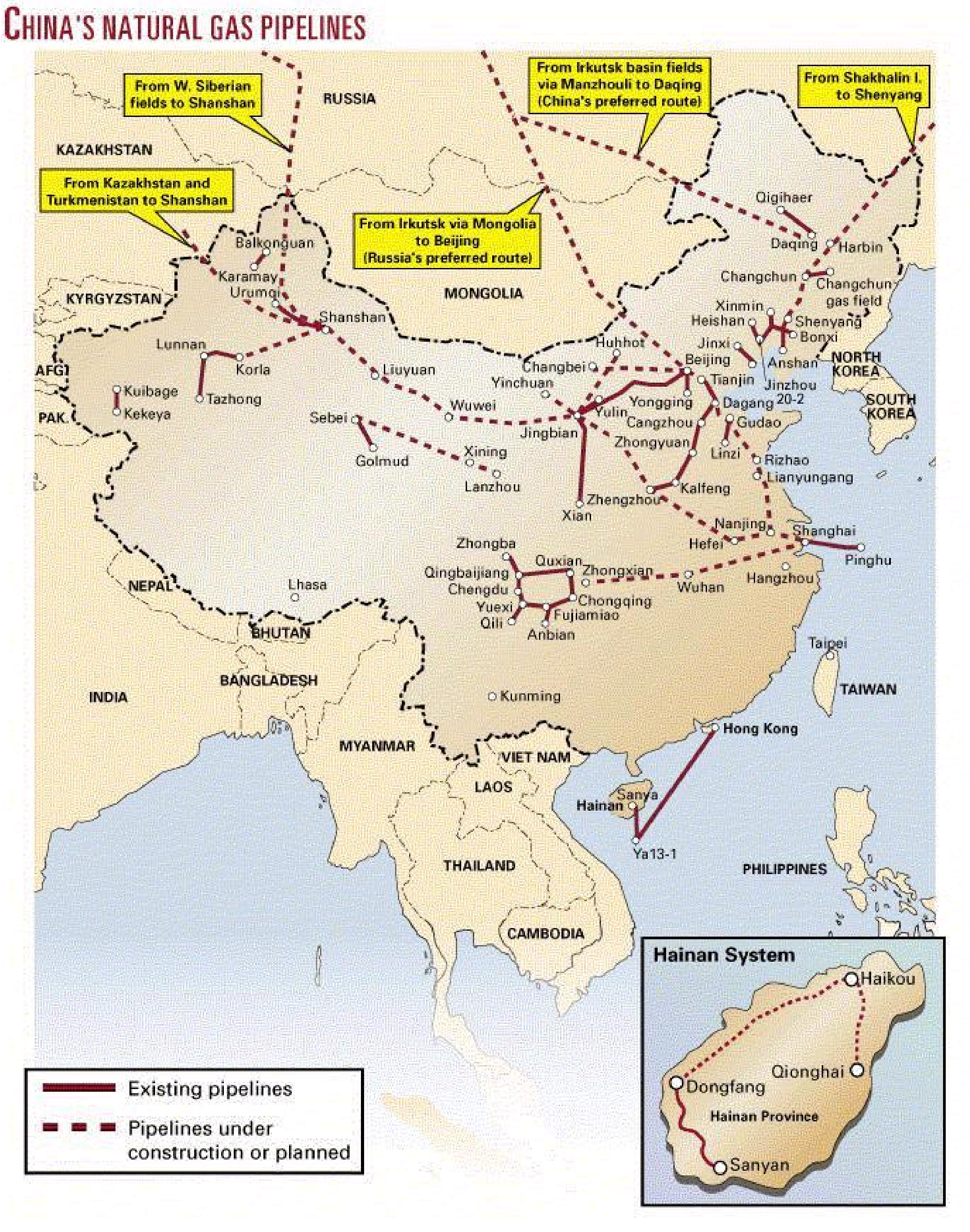


Figure B2 China's natural gas pipelines

Appendix B-3 The structure of natural gas industry in China

The main players in Chinese gas industry include:

1. The Chinese "majors"

- PetroChina (formerly China National Petroleum Corporation [CNPC]), who controls 70 percent of onshore gas resources
- Sinopec who holds the faster-growing energy markets of the south
- China National Offshore Oil Corporation (CNOOC), has nearly total control of offshore resource development; and is the monopoly lead-developer of LNG projects by central government choice in China.

2. The State development planning commission (SDPC)

The SDPC is charged with economic and energy planning, energy pricing decisions, and the preliminary approval of energy projects—including all gas projects.

3. State economic and trade commission (SETC)

Regulatory authority for existing gas projects is vested in the Petroleum and Chemical Bureau of the SETC. Although SETC is involved in project planning and evaluation and must "sign off" on new projects, it is mainly concerned with regulation and management of operating facilities.

4. **City governments**

City governments hold the key to the implementation of environmental regulation and taxation that will level the playing field and close the price gap between natural gas and other fuels, especially coal. City governments also will hold the key to encouraging large industrial users to sign new contracts for natural gas supply.

Chinese regulators and firms are increasingly open to foreign equity participation in gas projects, including segments previously restricted to outside investment such as transportation and distribution. Pronouncements of greater access have lately coincided with the West-to-East megaproject, but there is some optimism that a change in practice might lead to a formal, permanent revision of investment rules.

5. Natural gas pricing in China

China's natural gas prices are determined by the SDPC. Typically, price determination involves a balance between the price required to support the investment and a price that will be acceptable to end users. It is an iterative process, subject to bargaining.

Natural gas remains generally expensive for most end users, especially in the industrial sector: factories wishing to convert to natural gas have to absorb the cost of burner conversion in addition to the cost of connecting. Only manufacturers that are convinced that greater fuel efficiency and a cleaner production process are worth the capital layout will endeavor to convert.

Residential customers are more captive to networking efforts by city gas companies and receive heavily subsidized prices.

Appendix C LNG shipyard

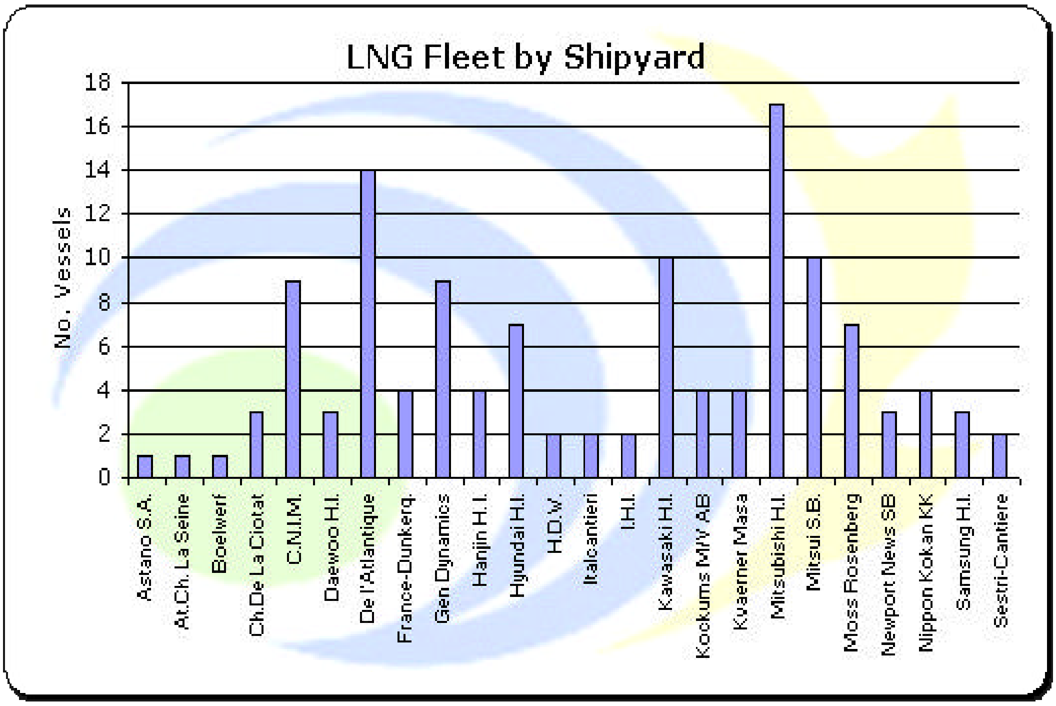
The following yards have the facilities to build LNG carriers.
In Europe

- Finland: Kvaerner Masa
- Germany: Howaldtswerke (HDW)
- France: Chantiers de l’Atlantique
- Italy: Fincantieri
- Spain: Izar

In Asia

- Japan
  - Mitsubishi Heavy Industries (MHI)
  - Mitsui Engineering and Shipbuilding (MES)
  - Kawasaki Heavy Industries (KHI)
  - Ishikawajima Harima Heavy Industries (IHI)
  - NKK
- Korea
  - Hyundai Heavy Industries (HHI)
  - Hanjin Heavy Industries
  - Samsung Heavy Industries
  - Daewoo Shipbuilding and Marine Engineering (DSME)

Figure C1 shows ship yares building LNG tankers



Source: LNGoneworld

Figure C1 LNG fleet by shipyard

Appendix D Technical features of LNG terminal system

The technical features of one typical LNG receiving terminal is list below (Table D).

Table D Example of Status of Main Facilities for a LNG terminal

- *PYEONGTAEK LNG TERMINAL (Korea) (As of Apr. 2001)*

Facilities		Unit	Capacity(Total Capacity)
Unloading Arm	LNG	7	4,200m3/hr/unit (29,400m3/hr)
	BOG	2	12,600Nm3/hr/unit
	LN2	2	BOG 2 12,600Nm3/hr/unit
	B.C.	2	680m3/hr/unit
	D.O.	2	
LNG Storage Tank	Aboveground	10	100,000kl/unit (1,000,000kl)
BOG Facilities	BOG Compressor	6	12,000Nm3/hr/unit (72,000Nm3)
	Flare Stack	1	95,000m3/hr/unit
LNG Pump	Low Pressure	22	150t/hr/unit (3,300t/hr)
	High Pressure	6	80t/hr/unit (480t/hr)
		14	110t/hr/unit (1,540t/hr)
Vaporization	LP ORV	3	90t/hr/unit (270t/hr)
	HP ORV	2	130t/hr/unit (260t/hr)
		7	180t/hr/unit (1,260t/hr)
	HP SMV	2	68t/hr/unit (136t/hr)
		4	90t/hr/unit (360t/hr)
Vaporization Sea Water Pump		11	10,000m3/hr/unit (110,000m3/hr)
Re-condensor		1	60t/hr
Metering System	Low Pressure	4	27-270t/hr
	Middle Pressure	2	14-72t/hr
		2	2-72t/hr
	High Pressure	2	38-800t/hr
		2	70-1,400t/hr

Appendix E Formulation of the optimisation of LNG chains

Linear programming (LP) has been developed to resolve problems in operational research, such as transportation, assignment, sequencing and routing problems etc. (French, 1986, p5). The optimisation of LNG chain can be formulated and resolved by LP method.

It is clear that objective of the problem in this paper can be described how to minimise the total costs or unit cost of LNG chain. As discussed before, the decision variables include gas demand, place of gas resource, LNG shipping costs and re-gasification costs.

The fatal factor to plan LNG chain is demand of end-users. Whether a LNG import project get success or not depends on the deviation and uncertain of LNG demand. Forecasting LNG demand or market analysis exceeds this research. However, the impact of change of demand will be born into mind.

One of the main assumptions is that only one type of ship is used and only one place of gas resource is selected each time in LNG import project. This assumption is based on the LNG projects conducted now.

It can be described that there are a set i of ships and a set j of gas resource places, only one type of ship s in i has to be exactly to delivery gas from only one place in j at each solution. All those alternative places of gas resources are assumed to have sufficient amount of natural gas to meet buyer's demand. This assumption is based on characteristics of contract of LNG projects.

The optimising process can be described as the following:

$$\text{Minimise } M = \sum_i \sum_j x_{ij} \times (n_{ij} \times tc_i + voy_{ij} \times vc_{ij} + de \times fob_j + de \times pc_i)$$

Subject to

$$\sum_i x_{ij} = 1, \text{ for all i (i.e. i is assigned to exactly one j)}$$

$$\sum_j x_{ij} = 1, \text{ for all j (i.e. j has exactly one I assigned to it)}$$

$$x_{ij} = 0 \text{ or } 1, \text{ for all i and j}$$

$$\sum_i \sum_j x_{ij} voy_{ij} \times s_i \geq de$$

$$n_{ij} \times 350 / vd_j \geq voy_{ij} \text{ , for all i,j}$$

$voy_{ij} \geq 0$

$n_{ij} \geq 0$

de- LNG demand per annum

fob_j- FOB price of LNG in place j

pc_i- re-gasification costs of LNG for ship i

tc_i- T/C rate of i ship

n_{ij}- numver of ship i needed for place j

voy_{ij}- ship calls of ship i for place j

vc_{ij}- round voyage costs of ship i for place j

vd_j- round voyage days for place j

s_i- ship size of ship i

Appendix F Brief of Guangdong LNG terminal project

Guangdong LNG terminal will be built in Shenzhen, which import LNG to meet the energy requirements in Pearl River Delta (PRD), South China. There will be two phases in the project. Phase 1 of the Project, with a scale of 3mm ton/a, is estimated to be in operation in 2005 and Phase 2 of the Project is estimated to have a scale of 5mm ton/a (Alberta, 2002). The main scenarios include:

1. Investment and project structure

The total investment in the terminal and trunkline at Phase 1 is 5.1 billion Yuan (600 milliong US$). The total investment at Phase 2 will amount to 2.1 billion Yuan (250 million US$). China National Offshore Oil Corporation ("CNOOC") took the lead and organized the planning and studies. The Project is a Sino-foreign joint venture of which CNOOC taking up 33% of the interest, BP 30%, Guangdong sponsors 31%, and Hongkong Electric Holdings Limited and The Hong Kong & China Gas Company Limited each has 3%. As the wholesale LNG buyer, the joint venture will purchase LNG and sell pipeline gas to power plants and town gas users.

2. Main consumers

It supplies gas to the following users of 4 fields in the PRD and HongKong Special Administrative Region (HKSAR):

2.1 Town gas in the 9 cities in the PRD(including civil and industrial users)

The trunkline runs from Shenzhen to Dongguan, Guangzhou and Foshan in Phase 1 and extends to Huizhou, Zhaoqing, Jiangmen, Zhongshan and Zhuhai in Phase 2. In this project gas will be delivered to the gas receiving stations in every city.

2.2 New power plant

The construction of new power plants is subject to the feasibility study and the power supply situation in Guangdong. The project will supply gas to the new power plants.

2.3 Oil-to-gas power plant

In Phase 1 the Project will directly supply gas to Meishi Power Plant. Phase 2 includes Desheng Power Plant and Shakou Power Plant in Foshan, it is tentatively planned that gas will be delivered to them from the local town gas network.

2.4 Gas consumption in the HKSAR

It includes the power plant of HK Electric Co., Ltd. ("**HK Electric**") and town gas project of HK and China Gas Company.

3. Terminal

The terminal is located at Chengtoujiao, which lies on the eastern shore of Dapeng Bay in the east wing of Shenzhen. With favorable geological engineering conditions, the site has sufficient land for construction. With reliable conditions of water supply for construction and living, power supply and telecommunication, the natural conditions for jetty construction there are also ideal.

Jetty

There is a berth in the harbor to accommodate a LNG carrier of 135,000 m^3. The jetty is 450 meters long and the berthing water depth is –13.2 meters. Beside the main berth, there is also a barge berth.

Storage tanks

There will be two storage tanks of 135,000 m^3 in Phase 1 and another storage tank of about 100,000 m^3 in Phase 2.

Vaporizers

The terminal is equipped with an open rack seawater vaporizer and a high pressure submerged combustion vaporizer. The latter is for peak-shaving and standby use. The vaporization capacity is 1,200 m^3 LNG/h in Phase 1.

4. Trunkline

The trunkline runs 215.4 km from Chengtoujiao to Pingshan, Dongguan, Guangzhou and Foshan in Phase 1 and 181.7 km in Phase 2.

Appendix G-1 Estimation of total costs in Scenario 1

Table 1. Distance between gas resources and China

Export Port	Indonesia	Australia	Qatar
Receiving Port	China	China	China
Distance (miles)	**1900**	**2773**	**5068**

Table 2. Estimated FOB costs of LNG (US$/MMBtu)

Country	Indonesia	Australia	Qatar
Project/port	Tangguh	Northwest Shelf/	RasGas/QatarGas
FOB price	**1.8**	**1.35**	**1.25**

Table 3. Estimated shipping costs (US$/MMBtu)

Ship size	Indonesia	Australia	Qatar
125000	0.47	0.49	0.89
138000	0.48	0.50	0.75
147000	0.49	0.51	0.76
160000	0.50	0.52	0.79
200000	0.33	0.56	0.63

Table 4. Estimated re-gasification costs (US$/MMBtu)

Ship size (cubic meter)	125000	138000	147000	160000	200000
Total capital cost of receiving terminal (million US$)	378	417	444	483	604
Full Regas Cost (in US$ per MMBtu Output)	**0.51**	**0.57**	**0.60**	**0.66**	**0.82**

Table 5. Total LNG chain costs (US$/MMBtu)

Gas resource	Indonesia					Australia					Qatar				
Distance to China	1,900					2,773					5,068				
Ship size	125,000	138,000	147,000	160,000	200,000	125,000	138,000	147,000	160,000	200,000	125,000	138,000	147,000	160,000	200,000
Liquefication and export costs	1.8	1.8	1.8	1.8	1.8	1.35	1.35	1.35	1.35	1.35	1.25	1.25	1.25	1.25	1.25
shipping costs	0.47	0.48	0.49	0.50	0.33	0.49	0.50	0.51	0.52	0.56	0.89	0.75	0.76	0.79	0.63
Receiving and regas costs	0.51	0.57	0.60	0.66	0.82	0.51	0.57	0.60	0.66	0.82	0.51	0.57	0.60	0.66	0.82
Total unit cost	**2.78**	**2.85**	**2.89**	**2.95**	**2.95**	**2.35**	**2.41**	**2.46**	**2.53**	**2.73**	**2.66**	**2.57**	**2.62**	**2.69**	**2.70**

Appendix G-2 Estimation of total costs in Scenario 1

Table 1. Distance between gas resources and China

Export Port	Indonesia	Australia	Qatar
Receiving Port	China	China	China
Distance (miles)	**1900**	**2773**	**5068**

Table 2. Estimated FOB costs of LNG (US$/MMBtu)

Country	Indonesia	Australia	Qatar
Project/port	Tangguh	Northwest Shelf/	RasGas/QatarGas
FOB price	**1.8**	**1.35**	**1.25**

Table 3. Estimated shipping costs (US$/MMBtu)

Ship size	Indonesia	Australia	Qatar
125000	0.44	0.56	0.83
138000	0.45	0.47	0.86
147000	0.45	0.48	0.77
160000	0.35	0.49	0.78
200000	0.37	0.39	0.72

Table 4. Estimated re-gasification costs (US$/MMBtu)

Ship size (cubic meter)	125000	138000	147000	160000	200000
Total capital cost of receiving terminal (million US$)	378	417	444	483	604
Full Regas Cost (in US$ per MMBtu Output)	**0.31**	**0.34**	**0.36**	**0.39**	**0.49**

Table 5. Total LNG chain costs (US$/MMBtu)

Gas resource	Indonesia					Australia					Qatar				
Distance to China	1,900					2,773					5,068				
Ship size	125,000	138,000	147,000	160,000	200,000	125,000	138,000	147,000	160,000	200,000	125,000	138,000	147,000	160,000	200,000
Liquefication and export costs	1.8	1.8	1.8	1.8	1.8	1.35	1.35	1.35	1.35	1.35	1.25	1.25	1.25	1.25	1.25
shipping costs	0.44	0.45	0.45	0.35	0.37	0.56	0.47	0.48	0.49	0.39	0.83	0.86	0.77	0.78	0.72
Receiving and regas costs	0.31	0.34	0.36	0.39	0.49	0.31	0.34	0.36	0.39	0.49	0.31	0.34	0.36	0.39	0.49
Total unit cost	**2.55**	**2.59**	**2.61**	**2.55**	**2.66**	**2.21**	**2.16**	**2.19**	**2.23**	**2.23**	**2.39**	**2.45**	**2.38**	**2.43**	**2.46**

Appendix G-3 Calculation results of shipping costs in Scenario 1

1. Expected transport volume: 3 million tons LNG per annum.

2. Ship calls needed to China

	Gas resource		
Ship size (cubic meter)	Australia	Indonesia	Qatar
125000	55	54	55
138000	50	49	50
147000	47	46	47
160000	43	43	43
200000	34	34	35

3. Ship number needed

	Gas resource		
Ship size	Australia	Indonesia	Qatar
125000	2.1	1.7	3.6
138000	1.9	1.6	3.3
147000	1.8	1.5	3.1
160000	1.7	1.3	2.8
200000	1.3	1.1	2.2

4. Expected Number of chartered ships

	Gas resource		
Ship size	Australia	Indonesia	Qatar
125000	2	2	4
138000	2	2	3
147000	2	2	3
160000	2	2	3
200000	2	1	2

5. Utilization of ship capacity (%)

	Ship route		
Ship size	Australia-China	Indonesia-China	Qatar-China
125000	107%	86%	90%
138000	97%	78%	108%
147000	91%	73%	102%
160000	84%	67%	94%
200000	67%	108%	112%

Note: The percentage that is larger than 100% means the ships' transport capacities are less than expected gas imports volume.

6. Estimated time charter costs of LNGC (million US$ per annum)

		Gas resource		
Ship size	TCE rate (US$ per day)	Australia	Indonesia	Qatar
125000	63,222	44.3	44.3	88.5
138000	67,323	47.1	47.1	70.7
147000	70,002	49.0	49.0	73.5
160000	73,796	51.7	51.7	77.5
200000	84,799	59.4	29.7	59.4

7. Estimated ship voyage costs (US$ per round trip)

	Gas resource		
Ship size	Australia	Indonesia	Qatar
125000	457007	395430	662263
138000	477688	412094	696335
147000	492006	423630	719923
160000	512687	440294	753995
200000	576321	491568	858831

8. Total Unit shipping costs (US$ per MMBtu)

	Gas resource		
Ship size	Australia	Indonesia	Qatar
125000	0.49	0.47	0.89
138000	0.50	0.48	0.75
147000	0.51	0.49	0.76
160000	0.52	0.50	0.79
200000	0.56	0.33	0.63

Appendix G-4 Calculation results of shipping costs in Scenario 2

1. Expected transport volume: 5 million tons LNG per annum.

2. Ship calls needed to China

	Gas resource		
Ship size (cubic meter)	Australia	Indonesia	Qatar
125000	91	90	92
138000	82	82	83
147000	77	77	78
160000	71	71	72
200000	57	57	58

3. Ship number needed

	Gas resource		
Ship size	Australia	Indonesia	Qatar
125000	3.6	2.9	6.0
138000	3.2	2.6	5.4
147000	3.0	2.4	5.1
160000	2.8	2.2	4.7
200000	2.2	1.8	3.7

4. Expected Number of chartered ships

	Gas resource		
Ship size	Australia	Indonesia	Qatar
125000	4	3	6
138000	3	3	6
147000	3	3	5
160000	3	2	5
200000	2	2	4

5. Utilization of ship capacity (%)

	Ship route		
Ship size	Australia-China	Indonesia-China	Qatar-China
125000	90%	96%	100%
138000	108%	87%	90%
147000	102%	81%	102%
160000	93%	112%	94%
200000	112%	90%	94%

Note: The percentage that is larger than 100% means the ships' transport capacities are less than expected gas imports volume.

6. Estimated time charter costs of LNGC (million US$ per annum)

		Gas resource		
Ship size	TCE rate (US$ per day)	Australia	Indonesia	Qatar
125000	63,222	88.5	66.4	132.8
138000	67,323	70.7	70.7	141.4
147000	70,002	73.5	73.5	122.5
160000	73,796	77.5	51.7	129.1
200000	84,799	59.4	59.4	118.7

7. Estimated ship voyage costs (US$ per round trip)

	Gas resource		
Ship size	Australia	Indonesia	Qatar
125000	457007	395430	662263
138000	477688	412094	696335
147000	492006	423630	719923
160000	512687	440294	753995
200000	576321	491568	858831

8. Total Unit shipping costs (US$ per MMBtu)

	Gas resource		
Ship size	Australia	Indonesia	Qatar
125000	0.56	0.44	0.83
138000	0.47	0.45	0.86
147000	0.48	0.45	0.77
160000	0.49	0.35	0.78
200000	0.39	0.37	0.72

Appendix G-5 Calculation results of time charter rates of LNGC

Table 1 Estimated TCE rate of 125,000 m^3 LNG ship

VESSEL DETAILS

Name	*LNG_125000*
Dwt	0
Ldt	0
Built	1998
Age (years)	-
Economic Life	20
Remaining	22

FINANCE DETAILS

Price	: US$	155,136,579
Deposit/Price	:	25.00%
Deposit	: US$	38,784,145
Loan/Price Ratio	:	75.00%
Loan	: US$	116,352,435
Loan Term	:	10.0
Interest Rate	:	6.00%

RESIDUAL VALUES

Secondhand	
Resale Value : US$	-
Scrap Price	
US$/ldt :	-
Scrap Value : US$	-

COSTS AND REVENUES

TCE Revenue	: US$	63,222	per day
Escalation	:	0.00%	per annum
Trading Year	:	350	days
Operating Costs	: US$	11,081	per day
Escalation	:	0.00%	per annum

RESULTS

IRR	9.97%
Payback Period	
14	years

Year	NOMINAL VALUES - US$ MILLION: TCE Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow	Time Period	Discount Factor	PRESENT VALUES: US$ MILLION: Timecharter Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow
Initial Investment			-38.784		-38.784	-38.784	1	1.000			-38.784		-38.784	-38.784
1996			-2.580		-2.580	-41.364	2	0.909			-2.346		-2.346	-41.130
1997			-6.020		-6.020	-47.383	3	0.827			-4.978		-4.978	-46.108
1998	22.128	-4.045	-18.616		-0.533	-47.917	4	0.752	16.640	-3.041	-13.999		-0.401	-46.509
1999	22.128	-4.045	-17.918		0.165	-47.752	5	0.684	15.131	-2.766	-12.253		0.113	-46.396
2000	22.128	-4.045	-17.220		0.863	-46.889	6	0.622	13.760	-2.515	-10.708		0.537	-45.860
2001	22.128	-4.045	-16.522		1.561	-45.328	7	0.565	12.513	-2.287	-9.343		0.883	-44.977
2002	22.128	-4.045	-15.824		2.259	-43.069	8	0.514	11.379	-2.080	-8.137		1.162	-43.815
2003	22.128	-4.045	-15.126		2.957	-40.112	9	0.468	10.347	-1.891	-7.073		1.383	-42.432
2004	22.128	-4.045	-14.428		3.655	-36.457	10	0.425	9.409	-1.720	-6.135		1.554	-40.878
2005	22.128	-4.045	-13.730		4.353	-32.103	11	0.387	8.557	-1.564	-5.309		1.683	-39.195
2006	22.128	-4.045	-13.031		5.052	-27.052	12	0.352	7.781	-1.422	-4.582		1.776	-37.418
2007	22.128	-4.045	-12.333		5.750	-21.302	13	0.320	7.076	-1.293	-3.944		1.839	-35.580
2008	22.128	-4.045			18.083	-3.219	14	0.291	6.434	-1.176			5.258	-30.322
2009	22.128	-4.045			18.083	14.864	15	0.264	5.851	-1.070			4.782	-25.540
2010	22.128	-4.045			18.083	32.947	16	0.240	5.321	-0.973			4.348	-21.192
2011	22.128	-4.045			18.083	51.030	17	0.219	4.839	-0.884			3.954	-17.238
2012	22.128	-4.045			18.083	69.113	18	0.199	4.400	-0.804			3.596	-13.642
2013	22.128	-4.045			18.083	87.196	19	0.181	4.001	-0.731			3.270	-10.372
2014	22.128	-4.045			18.083	105.279	20	0.164	3.638	-0.665			2.973	-7.399
2015	22.128	-4.045			18.083	123.362	21	0.150	3.309	-0.605			2.704	-4.695
2016	22.128	-4.045			18.083	141.445	22	0.136	3.009	-0.550			2.459	-2.236
2017	22.128	-4.045		0.000	18.083	159.528	23	0.124	2.736	-0.500			2.236	0.000
2018							24	0.112						
2019							25	0.102						
2020							26	0.093						
2021							27	0.085						
2022							28	0.077						
2023							29	0.070						
2024							30	0.064						
2025							31	0.058						
Total	442.553	-80.893	-202.132	0.000	159.528				156.130	-28.538	-127.592	0.000	0.000	

Table 2 Estimated TCE rate of 138,000 m^3 LNG ship

THE INTERNAL RATE OF RETURN **BASE CASE**

VESSEL DETAILS		FINANCE DETAILS		RESIDUAL VALUES		COSTS AND REVENUES		RESULTS	
Name	*LNG_138000*	Price	: US$ 165,000,000	Secondhand		TCE Revenue : US$	67,323 per day	**IRR**	**10.00%**
Dwt	0	Deposit/Price	: 25.00%	Resale Value : US$	-	Escalation :	0.00% per annum		
Ldt	0	Deposit	: US$ 41,250,000					**Payback Period**	
Built	1998	Loan/Price Ratio	: 75.00%	Scrap Price		Trading Year :	350 days		
Age (years)	-	Loan	: US$ 123,750,000	US$/ldt :	-			**14**	**years**
Economic Life	20	Loan Term	: 10.0			Operating Costs : US$	11,786 per day		
Remaining	22	Interest Rate	: 6.00%	Scrap Value : US$	-	Escalation :	0.00% per annum		

Year	NOMINAL VALUES - US$ MILLION TCE Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow	Time Period	Discount Factor	PRESENT VALUES: US$ MILLION Timecharter Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow
Initial Investment			-41.250		-41.250	-41.250	1	1.000			-41.250		-41.250	-41.250
1996			-2.744		-2.744	-43.994	2	0.909			-2.494		-2.494	-43.744
1997			-6.402		-6.402	-50.396	3	0.826			-5.291		-5.291	-49.036
1998	23.563	-4.302	-19.800		-0.539	-50.935	4	0.751	17.704	-3.232	-14.877		-0.405	-49.440
1999	23.563	-4.302	-19.058		0.204	-50.731	5	0.683	16.095	-2.938	-13.017		0.139	-49.301
2000	23.563	-4.302	-18.315		0.946	-49.785	6	0.621	14.632	-2.671	-11.373		0.588	-48.714
2001	23.563	-4.302	-17.573		1.689	-48.096	7	0.565	13.302	-2.429	-9.920		0.953	-47.760
2002	23.563	-4.302	-16.830		2.431	-45.664	8	0.513	12.093	-2.208	-8.638		1.248	-46.512
2003	23.563	-4.302	-16.088		3.174	-42.491	9	0.467	10.994	-2.007	-7.506		1.481	-45.032
2004	23.563	-4.302	-15.345		3.916	-38.574	10	0.424	9.995	-1.825	-6.509		1.661	-43.370
2005	23.563	-4.302	-14.603		4.659	-33.915	11	0.386	9.086	-1.659	-5.631		1.797	-41.574
2006	23.563	-4.302	-13.860		5.401	-28.514	12	0.351	8.260	-1.508	-4.859		1.894	-39.680
2007	23.563	-4.302	-13.118		6.144	-22.370	13	0.319	7.510	-1.371	-4.181		1.958	-37.722
2008	23.563	-4.302			19.261	-3.109	14	0.290	6.827	-1.246			5.581	-32.142
2009	23.563	-4.302			19.261	16.152	15	0.263	6.206	-1.133			5.073	-27.068
2010	23.563	-4.302			19.261	35.414	16	0.239	5.642	-1.030			4.612	-22.456
2011	23.563	-4.302			19.261	54.675	17	0.218	5.130	-0.936			4.193	-18.263
2012	23.563	-4.302			19.261	73.936	18	0.198	4.663	-0.851			3.812	-14.451
2013	23.563	-4.302			19.261	93.198	19	0.180	4.239	-0.774			3.465	-10.986
2014	23.563	-4.302			19.261	112.459	20	0.164	3.854	-0.704			3.150	-7.835
2015	23.563	-4.302			19.261	131.720	21	0.149	3.504	-0.640			2.864	-4.971
2016	23.563	-4.302			19.261	150.982	22	0.135	3.185	-0.582			2.604	-2.367
2017	23.563	-4.302		0.000	19.261	170.243	23	0.123	2.896	-0.529			2.367	0.000
2018							24	0.112						
2019							25	0.102						
2020							26	0.092						
2021							27	0.084						
2022							28	0.076						
2023							29	0.069						
2024							30	0.063						
2025							31	0.057						
Total	471.262	-86.036	-214.984	0.000	170.243				165.819	-30.273	-135.546	0.000	0.000	

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Table 3 Estimated TCE rate of 147,000 m^3 LNG ship

VESSEL DETAILS

Name	*LNG_147,000*
Dwt	0
Ldt	0
Built	1998
Age (years)	-
Economic Life	20
Remaining	22

FINANCE DETAILS

Price	: US$	171,623,981
Deposit/Price	:	25.00%
Deposit	: US$	42,905,995
Loan/Price Ratio	:	75.00%
Loan	: US$	128,717,986
Loan Term	:	10.0
Interest Rate	:	6.00%

RESIDUAL VALUES

Secondhand	
Resale Value : US$	-
Scrap Price	
US$/ldt :	-
Scrap Value : US$	-

COSTS AND REVENUES

TCE Revenue	: US$	70,002	per day
Escalation	:	0.00%	per annum
Trading Year	:	350	days
Operating Costs	: US$	12,259	per day
Escalation	:	0.00%	per annum

RESULTS

IRR	9.99%
Payback Period	
14	years

Year	TCE Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow	Time Period	Discount Factor	Timecharter Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow
	NOMINAL VALUES - US$ MILLION								PRESENT VALUES: US$ MILLION					
Initial Investment			-42.906		-42.906	-42.906	1	1.000			-42.906		-42.906	-42.906
1996			-2.854		-2.854	-45.760	2	0.909			-2.595		-2.595	-45.501
1997			-6.659		-6.659	-52.419	3	0.827			-5.505		-5.505	-51.005
1998	24.501	-4.474	-20.595		-0.569	-52.988	4	0.752	18.413	-3.363	-15.478		-0.427	-51.433
1999	24.501	-4.474	-19.823		0.204	-52.784	5	0.683	16.741	-3.057	-13.544		0.139	-51.293
2000	24.501	-4.474	-19.050		0.976	-51.808	6	0.621	15.220	-2.780	-11.834		0.606	-50.687
2001	24.501	-4.474	-18.278		1.748	-50.060	7	0.565	13.838	-2.527	-10.323		0.987	-49.700
2002	24.501	-4.474	-17.506		2.521	-47.539	8	0.514	12.581	-2.298	-8.989		1.294	-48.405
2003	24.501	-4.474	-16.733		3.293	-44.246	9	0.467	11.439	-2.089	-7.812		1.537	-46.868
2004	24.501	-4.474	-15.961		4.065	-40.181	10	0.424	10.400	-1.899	-6.775		1.726	-45.142
2005	24.501	-4.474	-15.189		4.838	-35.343	11	0.386	9.455	-1.727	-5.861		1.867	-43.275
2006	24.501	-4.474	-14.416		5.610	-29.733	12	0.351	8.596	-1.570	-5.058		1.968	-41.307
2007	24.501	-4.474	-13.644		6.382	-23.351	13	0.319	7.816	-1.427	-4.352		2.036	-39.271
2008	24.501	-4.474			20.026	-3.324	14	0.290	7.106	-1.298			5.808	-33.463
2009	24.501	-4.474			20.026	16.702	15	0.264	6.460	-1.180			5.281	-28.182
2010	24.501	-4.474			20.026	36.728	16	0.240	5.874	-1.073			4.801	-23.381
2011	24.501	-4.474			20.026	56.754	17	0.218	5.340	-0.975			4.365	-19.016
2012	24.501	-4.474			20.026	76.781	18	0.198	4.855	-0.887			3.969	-15.048
2013	24.501	-4.474			20.026	96.807	19	0.180	4.414	-0.806			3.608	-11.440
2014	24.501	-4.474			20.026	116.833	20	0.164	4.013	-0.733			3.280	-8.159
2015	24.501	-4.474			20.026	136.860	21	0.149	3.649	-0.666			2.982	-5.177
2016	24.501	-4.474			20.026	156.886	22	0.135	3.317	-0.606			2.712	-2.465
2017	24.501	-4.474		0.000	20.026	176.912	23	0.123	3.016	-0.551			2.465	0.000
2018							24	0.112						
2019							25	0.102						
2020							26	0.093						
2021							27	0.084						
2022							28	0.076						
2023							29	0.070						
2024							30	0.063						
2025							31	0.057						
Total	490.016	-89.490	-223.614	0.000	176.912				172.544	-31.511	-141.033	0.000	0.000	

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Table 4 Estimated TCE rate of 160,000 m^3 LNG ship

VESSEL DETAILS

Name	*LNG_160,000*
Dwt	0
Ldt	0
Built	1998
Age (years)	-
Economic Life	20
Remaining	22

FINANCE DETAILS

Price	: US$	180,928,100
Deposit/Price	:	25.00%
Deposit	: US$	45,232,025
Loan/Price Ratio	:	75.00%
Loan	: US$	135,696,075
Loan Term	:	10.0
Interest Rate	:	6.00%

RESIDUAL VALUES

Secondhand	
Resale Value : US$	-
Scrap Price	
US$/ldt :	-
Scrap Value : US$	-

COSTS AND REVENUES

TCE Revenue : US$	73,796	per day
Escalation :	0.00%	per annum
Trading Year :	350	days
Operating Costs : US$	12,923	per day
Escalation :	0.00%	per annum

RESULTS

IRR	9.99%
Payback Period	
14	years

Year	NOMINAL VALUES - US$ MILLION: TCE Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow	Time Period	Discount Factor	PRESENT VALUES: US$ MILLION: Timecharter Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow
Initial Investment			-45.232		-45.232	-45.232	1	1.000			-45.232		-45.232	-45.232
1996			-3.009		-3.009	-48.241	2	0.909			-2.735		-2.735	-47.967
1997			-7.020		-7.020	-55.261	3	0.827			-5.803		-5.803	-53.770
1998	25.829	-4.717	-21.711		-0.600	-55.861	4	0.752	19.411	-3.545	-16.317		-0.451	-54.221
1999	25.829	-4.717	-20.897		0.215	-55.646	5	0.683	17.648	-3.223	-14.279		0.147	-54.075
2000	25.829	-4.717	-20.083		1.029	-54.617	6	0.621	16.045	-2.930	-12.476		0.639	-53.436
2001	25.829	-4.717	-19.269		1.843	-52.775	7	0.565	14.588	-2.664	-10.883		1.041	-52.395
2002	25.829	-4.717	-18.455		2.657	-50.118	8	0.514	13.263	-2.422	-9.477		1.364	-51.030
2003	25.829	-4.717	-17.640		3.471	-46.646	9	0.467	12.059	-2.202	-8.236		1.621	-49.410
2004	25.829	-4.717	-16.826		4.285	-42.361	10	0.424	10.964	-2.002	-7.142		1.819	-47.591
2005	25.829	-4.717	-16.012		5.100	-37.261	11	0.386	9.968	-1.820	-6.179		1.968	-45.623
2006	25.829	-4.717	-15.198		5.914	-31.348	12	0.351	9.063	-1.655	-5.333		2.075	-43.548
2007	25.829	-4.717	-14.384		6.728	-24.620	13	0.319	8.240	-1.505	-4.589		2.146	-41.401
2008	25.829	-4.717			21.112	-3.508	14	0.290	7.491	-1.368			6.123	-35.278
2009	25.829	-4.717			21.112	17.604	15	0.264	6.811	-1.244			5.567	-29.711
2010	25.829	-4.717			21.112	38.715	16	0.240	6.192	-1.131			5.061	-24.650
2011	25.829	-4.717			21.112	59.827	17	0.218	5.630	-1.028			4.602	-20.048
2012	25.829	-4.717			21.112	80.939	18	0.198	5.119	-0.935			4.184	-15.864
2013	25.829	-4.717			21.112	102.050	19	0.180	4.654	-0.850			3.804	-12.060
2014	25.829	-4.717			21.112	123.162	20	0.164	4.231	-0.773			3.458	-8.602
2015	25.829	-4.717			21.112	144.274	21	0.149	3.847	-0.703			3.144	-5.458
2016	25.829	-4.717			21.112	165.386	22	0.135	3.497	-0.639			2.859	-2.599
2017	25.829	-4.717		0.000	21.112	186.497	23	0.123	3.180	-0.581			2.599	0.000
2018							24	0.112						
2019							25	0.102						
2020							26	0.093						
2021							27	0.084						
2022							28	0.076						
2023							29	0.070						
2024							30	0.063						
2025							31	0.057						
Total	516.575	-94.341	-235.737	0.000	186.497				181.901	-33.220	-148.681	0.000	0.000	

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Table 5 Estimated TCE rate of 200,000 m³ LNG ship

VESSEL DETAILS

Name	*LNG_200,000*
Dwt	0
Ldt	0
Built	1998
Age (years)	-
Economic Life	20
Remaining	22

FINANCE DETAILS

Price	: US$	207,912,672
Deposit/Price	:	25.00%
Deposit	: US$	51,978,168
Loan/Price Ratio	:	75.00%
Loan	: US$	155,934,504
Loan Term	:	10.0
Interest Rate	:	6.00%

RESIDUAL VALUES

Secondhand	
Resale Value : US$	-
Scrap Price	
US$/ldt :	-
Scrap Value : US$	-

COSTS AND REVENUES

TCE Revenue : US$	84,799	per day
Escalation :	0.00%	per annum
Trading Year :	350	days
Operating Costs : US$	14,851	per day
Escalation :	0.00%	per annum

RESULTS

IRR	**9.99%**
Payback Period	
14	**years**

Year	NOMINAL VALUES - US$ MILLION: TCE Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow	Time Period	Discount Factor	PRESENT VALUES: US$ MILLION: Timecharter Revenue	Operating Costs	Capital Outflow	Capital Inflow	Annual Net Cashflow	Cumulative Net Cashflow
Initial Investment			-51.978		-51.978	-51.978	1	1.000			-51.978		-51.978	-51.978
1996			-3.457		-3.457	-55.436	2	0.909			-3.143		-3.143	-55.122
1997			-8.067		-8.067	-63.503	3	0.827			-6.669		-6.669	-61.790
1998	29.680	-5.421	-24.950		-0.690	-64.193	4	0.752	22.306	-4.074	-18.751		-0.519	-62.309
1999	29.680	-5.421	-24.014		0.245	-63.948	5	0.683	20.280	-3.704	-16.409		0.168	-62.141
2000	29.680	-5.421	-23.078		1.181	-62.767	6	0.621	18.439	-3.368	-14.338		0.734	-61.408
2001	29.680	-5.421	-22.143		2.117	-60.651	7	0.565	16.764	-3.062	-12.507		1.195	-60.212
2002	29.680	-5.421	-21.207		3.052	-57.598	8	0.514	15.242	-2.784	-10.891		1.567	-58.645
2003	29.680	-5.421	-20.271		3.988	-53.611	9	0.467	13.858	-2.531	-9.465		1.862	-56.783
2004	29.680	-5.421	-19.336		4.923	-48.687	10	0.425	12.599	-2.301	-8.208		2.090	-54.693
2005	29.680	-5.421	-18.400		5.859	-42.828	11	0.386	11.455	-2.092	-7.102		2.261	-52.432
2006	29.680	-5.421	-17.465		6.795	-36.034	12	0.351	10.415	-1.902	-6.128		2.384	-50.047
2007	29.680	-5.421	-16.529		7.730	-28.304	13	0.319	9.469	-1.729	-5.273		2.466	-47.581
2008	29.680	-5.421			24.259	-4.044	14	0.290	8.609	-1.572			7.037	-40.544
2009	29.680	-5.421			24.259	20.215	15	0.264	7.827	-1.430			6.398	-34.147
2010	29.680	-5.421			24.259	44.474	16	0.240	7.117	-1.300			5.817	-28.330
2011	29.680	-5.421			24.259	68.733	17	0.218	6.470	-1.182			5.289	-23.041
2012	29.680	-5.421			24.259	92.992	18	0.198	5.883	-1.074			4.808	-18.233
2013	29.680	-5.421			24.259	117.252	19	0.180	5.348	-0.977			4.372	-13.861
2014	29.680	-5.421			24.259	141.511	20	0.164	4.863	-0.888			3.975	-9.886
2015	29.680	-5.421			24.259	165.770	21	0.149	4.421	-0.807			3.614	-6.273
2016	29.680	-5.421			24.259	190.029	22	0.135	4.020	-0.734			3.286	-2.987
2017	29.680	-5.421		0.000	24.259	214.288	23	0.123	3.655	-0.667			2.987	0.000
2018							24	0.112						
2019							25	0.102						
2020							26	0.093						
2021							27	0.084						
2022							28	0.076						
2023							29	0.070						
2024							30	0.063						
2025							31	0.057						
Total	593.596	-108.412	-270.896	0.000	214.288				209.040	-38.178	-170.862	0.000	0.000	

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Appendix G-6 Estimated re-gasification costs in Scenario 1

1. Assumptions

Capacity (MTPA)	**3.0**	
Construction Period	3	years
Leverage	0.7	
Debt Term	10	years
Interest Rate	0.08	
Depreciable Life	20	years
Target IRR (on equity)	15%	
Conversion Loss	2.5%	input gas
Working days per year	365	
Total Gas Output (MMcf per day)	400	
(MMBtu per day)	384658	

2. Calculation results

Ship size (cubic meter)	**125000**	**138000**	**147000**	**160000**	**200000**
Necessar storage capacity (cubic meter)	250000	276000	294000	320000	400000
Unit cost of storage (US$ per cubic meter)	710	710	710	710	710
Capital cost of storage (million US$)	178	196	209	227	284
Percentage of total caiptal cost	47%	47%	47%	47%	47%
Total capital cost of receiving terminal (million US$)	378	417	444	483	604
Re-gasification O&M (US$ per day)	31041	34269	36504	39732	49665
Re-gasification costs					
(in US$ per day)	196,912	217,414	231,808	252,209	315,609
(in million US$ per year)	71.9	79.4	84.6	92.1	115.2
Unit cost (in US$ per MMBtu output)	**0.51**	**0.57**	**0.60**	**0.66**	**0.82**

Appendix G-7 Estimated re-gasification costs in Scenario 2

1. Assumptions

Capacity (MTPA)	**5.0**	
Construction Period	3	years
Leverage	0.7	
Debt Term	10	years
Interest Rate	0.08	
Depreciable Life	20	years
Target IRR (on equity)	15%	
Conversion Loss	2.5%	input gas
Working days per year	365	
Total Gas Output (MMcf per day)	667	
(MMBtu per day)	641096	

2. Calculation results

Ship size (cubic meter)	**125000**	**138000**	**147000**	**160000**	**200000**
Necessar storage capacity (cubic meter)	250000	276000	294000	320000	400000
Unit cost of storage (US$ per cubic meter)	710	710	710	710	710
Capital cost of storage (million US$)	178	196	209	227	284
Percentage of total caiptal cost	47%	47%	47%	47%	47%
Total capital cost of receiving terminal (million US$)	378	417	444	483	604
Re-gasification O&M (US$ per day)	31041	34269	36504	39732	49665
Re-gasification costs					
(in US$ per day)	196,912	217,414	231,808	252,209	315,609
(in million US$ per year)	71.9	79.4	84.6	92.1	115.2
Unit cost (in US$ per MMBtu output)	**0.31**	**0.34**	**0.36**	**0.39**	**0.49**