An Operational Model for Liquefied Natural Gas Spot and Arbitrage Sales

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(BSc, MSc)

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This work is dedicated to my parents

> “A new scientific truth does not triumph by convincing its opponents and making them see the light, but rather because its opponents eventually die and a new generation grows up that is familiar with it.”
>
> Max Planck

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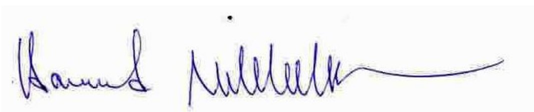
Declaration of Contribution

I hereby declare that the entire work described in this thesis has been carried out by myself, with advice from Prof Michael G. H. Bell (my supervisor) and that all material in this thesis which is not my own work has been properly acknowledged.



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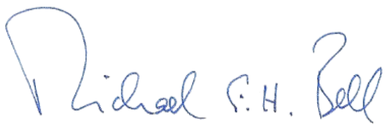

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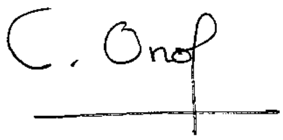

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(Dr Christian Onof)

Abstract

As more buyers become interested in the spot purchase of liquefied natural gas (LNG), the share of spot trade in LNG business increases. This means that the cash flowing into the upstream of LNG projects is a combination of that generated by deliveries to long-term contract (LTC) customers and uncommitted product and arbitrage spot sales. LTC cash flows are more predictable while uncommitted product and arbitrage cash flows, affected by the dynamics of supply and demand, are more volatile and therefore less predictable. In this research, we formulate an inventory routing problem (IRP) which maximizes the profit of an LNG producer with respect to uncommitted product and arbitrage spot sales, and also LTC deliveries at an operational level. Using the model, the importance of arbitrage, interest rates and compounding frequency in profit maximization, and also the significance of interest rates and fluctuation in spot prices in decision-making for spot sales of uncommitted product are studied. It is proven that writing traditional LTCs with relaxed destination clauses which assist in arbitrage is beneficial to the LNG producer. However, in contrast to what was predicted neither the interest rate nor the compounding frequency has any importance in profit maximization when no change of selling strategy is observed. Apart from these, it is shown that there is a trade-off between the expectation of higher spot prices and the inventory and shipping costs in decision-making for spot sales of uncommitted product in the LNG industry. Finally, it is observed that the interest rate can affect the set of decisions on spot sales of uncommitted product, although the importance of such changes in profit remains to be further explored.

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Glossary and Abbreviations

ADP	Annual delivery program, in tactical planning in the LNG industry, is a yearly plan that is formed by taking into account LNG seller's production profile and the long-term contract buyers' demand for LNG deliveries (both FOB and CIF/DES) and the dates these deliveries, in response to demands, should be carried out. Depending on the volume of a delivery several tankers together or just one may carry it out.
Alkane	Chemical compounds (C_nH_{2n+2}) that contains only hydrogen and carbon atoms. They have two main commercial sources: crude oil and natural gas.
bbl	An oil barrel equal to 159 liters
bcm	Billion cubic-meters
Branch-and-bound algorithm	A branch-and-bound algorithm is an algorithm that divides the set of candidate solutions into subsets and rejects the unrewarding subsets by using upper and lower estimated bounds of the problem objective function.
Branch-and-bound node limit	This is the maximum number of times that the dividing and rejecting process can occur in executing the branch-and-bound algorithm in IBM ILOG CPLEX Optimization Studio 12.3.
Branch-and-cut algorithm	This method is a hybrid of branch and bound and cutting plane methods. The algorithm solves the mixed integer programming problem as a linear program and finds an optimal solution (using the simplex method). If the solution found has a non-integer value, which should be integer, the cutting plane algorithm adds an inequality to the problem, and then the problem is solved again by the hope that the new solution will be less fractional. The process of adding inequalities and finding new solutions continues until an integer solution is found or no more inequalities can be added that may help in finding an integer solution.

CIF	Cost, insurance and freight is a term in trading that states the seller is responsible for delivering the cargo by sea to a destination port. He pays for the transport and insurance costs.
Commercial bank	A financial institution that lends money, accepts time deposits and offers accounts such as savings.
CPLEX	IBM ILOG CPLEX Optimization Studio (often informally referred to simply as CPLEX) is an optimization software package.
DES	Delivered ex-ship is a trade term by which the seller has to deliver the cargo to a buyer at an agreed destination port. The difference between CIF and DES terms is that the insurance in the CIF arrangement is issued in the name of the buyer (the seller pays for it) and the buyer should and can later claim for any damages against the insurance company. While in case of DES the insurance is in the name of the seller and he holds all the responsibilities until the goods are delivered to the buyer.
Direct delivery policy	A policy where a vessel only visits one and only one customer on each tour and delivers its whole cargo to that customer.
EBRD	European bank of reconstruction and development
Feasible solution space	The feasible solution space - also known as the set of candidate solutions - is the space that contains all the possible solutions to the problem. A possible solution is a solution that satisfies all the constraints in an optimization problem.
FERC	The Federal Energy Regulatory Commission (FERC) is the United States federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, and oil pipeline rates. FERC also reviews and authorizes liquefied natural gas (LNG) terminals, interstate natural gas pipelines and non-federal hydropower projects.
FOB	Free-on-board is a trade term that states that the seller delivers the goods on board a ship named by the buyer at the specific port of shipment. Seller passes all the risks and costs to the buyer when the cargo crosses the ship rail.
FSRU	Floating storage and regas unit in the LNG industry

Heuristic algorithm	The term heuristic is used for algorithms which find solutions among all possible ones, but they do not guarantee that the best will be found, therefore they may be considered as approximately and not accurate algorithms. These algorithms, usually find a solution close to the best one and they find it fast and easily.
Inter-regional pipeline	International/intercontinental gas pipelines
IOC	An international oil company
IRP	Inventory routing problem
JCC	Japan Customs-cleared Crude is the average price of customs-cleared crude oil imported to Japan.
Lagrangian relaxation method	A relaxation method that estimates a complicated optimization problem with a simple one. The solution to the simple problem can provide insights to the difficult problem. Sometimes the simple problem solution is the solution to the hard problem too.
LNG	Liquefied natural gas
Local search procedure	Local search algorithm moves from a solution to the other one in the feasible solution area with small changes. The moving continues until an optimized solution is found.
LP	Linear programming
LTC	Long-term contracts in the LNG industry which has two main types self-contracts and traditional contracts
MIP	Mixed integer programming
MMBtu	One million British thermal unit. A Btu is a traditional unit of energy equal to about 1.055 Kilo Joules.
MMscf/d	Million standard cubic feet per day
MT	Million tonnes
MTPA/mmtpa	Million tonnes per annum
Multilateral lender	An institution created by several countries that finances the projects often for the purpose of development. The finance is carried out in the form of long-term loans
NBP	National balancing point

NGL	Natural gas liquids are naturally occurring elements found in natural gas, and include propane, butane and ethane, among others. NGL are valuable as separate products and it is therefore profitable to remove them from the natural gas. The liquids are first extracted from the natural gas and later separated into different components
NOC	A national oil company
OFGEM	The Office of Gas and Electricity Markets is the government regulator for the electricity and downstream natural gas markets in Great Britain.
OPEC	Organization of the petroleum exporting countries
OTC	Over-the-counter trade is the direct trade of commodities (or other financial instruments) between the seller and buyer.
Partial delivery	A policy where a vessel visits several customers on each tour and delivers a portion of its cargo to each one.
Peak shaving LNG facilities	Peak shaving LNG facilities are typically small units often located close to major market demand areas. This type of LNG facility typically takes already processed gas from the grid in low demand periods, liquefies it and then stores it ready for the peak demand periods.
Permeability	In fluid mechanics and the earth sciences, permeability is a measure of the ability of a porous material to allow fluids to pass through it
Price risk	Risk resulting from the possibility that the price of a commodity may decline
RCPSP	A resource constrained project scheduling problem considers resources of limited availability and activities of known durations and resource requests, linked by precedence.
Regas terminal	Regasification terminal

Relative MIP gap tolerance	The relative MIP gap tolerance in IBM ILOG CPLEX Optimization Studio 12.3 is the acceptable difference where the search for the solution stops, between the LP bound and the best integer solution found for the MIP model in the course of branch-and-bound algorithm application. LP problem is a relaxed version of the MIP problem where all the decision-variables are relaxed to continuous. Solving the continuous problem is much easier than the MIP problem and the solution to that provides a limit/bound to the MIP problem.
Rolling horizon	To update and extend an existing plan in each period where the set of periods make the problem scope.
Routing	Routing is the process of selecting paths in a network along which to send network traffic.
SIRP	Strategic inventory routing problem
Toe	Tonne of oil equivalent is a unit of energy and it is equal to the amount of power released in burning one tonne of crude oil.
VMI	Vendor managed inventories
Volume risk	Risk resulting from possibility of not finding a buyer for a commodity
VRP	Vehicle routing problem

Chapter 1

Introduction

1.1. Background

Natural gas is an important resource and the world's third largest source (about 20%) of primary energy (EIA, 2011). It is a fossil fuel that is formed from the remains of plants and animals that lived 200 to 400 million years ago (NEED, 2004).

Natural gas, which is mainly methane, is odourless, colourless and tasteless. Upon combustion, it emits the lowest carbon dioxide per unit of generated energy among the fossil fuels. It burns clear and produces very few non-carbon emissions and, unlike oil, requires very limited processing before usage. These features make natural gas suitable for many markets including heating, industrial processes and electricity generation (Moniz et al., 2011).

The ancient Greek, Persian and Indian civilizations discovered natural gas about 3 000 years ago, in the form of burning springs of gas emanating from the ground. Unable to explain the phenomenon, they often built temples around the flames to worship the deities to which they attributed the event. The first intentional usage of natural gas was 2500 years ago in China, when locals constructed pipes to transport natural gas from shallow wells for burning under seawater pots used in salt extraction (Mokhatab et al., 2006).

Britain was the first country to commercially exploit natural gas, in 1785, with the earliest applications being in house and street lighting. The arrival of electricity at the beginning of the 20th century signalled the start of the search for other uses for natural gas. However, it was only after World War II that, due to progress in welding techniques, pipe rolling and metallurgical advances the extensive supply and usage of gas in houses and industry became possible (Natural Gas, 2004).

1.1.1. Establishment of the natural gas market

Natural gas, historically, has been extracted from conventional sources, i.e. associated and non-associated gas reservoirs; in associated gas reservoirs oil and gas are found together, whereas in non-associated deposits there is only gas (Mokhatab et al., 2006). Conventional sources are found in distinct, well-defined subsurface accumulations (reservoirs), with permeability rates larger than a specified lower limit. These reservoirs are trapped under an impermeable rock formation, known as seals. Conventional sources can usually be developed/extracted using vertical wells (Moniz et al., 2011).

The main unconventional sources of natural gas are tight sand, coal bed and shale gas. In contrast to conventional sources, unconventional sources are found in accumulations where permeability is low (Moniz et al., 2011). In tight sand sources, gas is trapped in a relatively impermeable sandstone formation. In coal beds, gas is trapped in the pores of the coal (also known as a coal matrix). Finally shale gas, refers to accumulations of gas trapped in a fine grained sedimentary rock named shale (McGlade et al., 2012).

It should be noted that unconventional accumulations are distributed over a larger area than conventional reservoirs and usually require advanced technology such as horizontal wells to aid extraction (Moniz et al., 2011). Figure 1.1 shows different sources of natural gas.

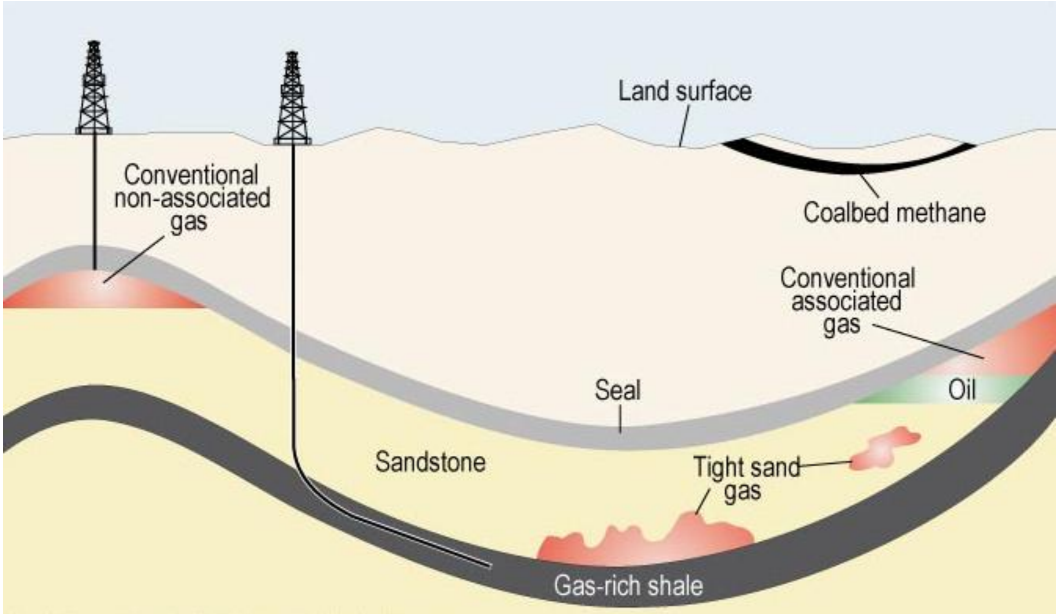

Figure 1.1 - Gas deposits (source: http:/bit.ly/15VV0hx)

Over the last two decades energy companies have started exploring specifically for natural gas and gas reserves have grown considerably. Before that the exploration target was almost always oil, and gas was found occasionally by accident (UBS, 2004). Figure 1.2 shows the distribution of gas sources and its increase over the past two decades.

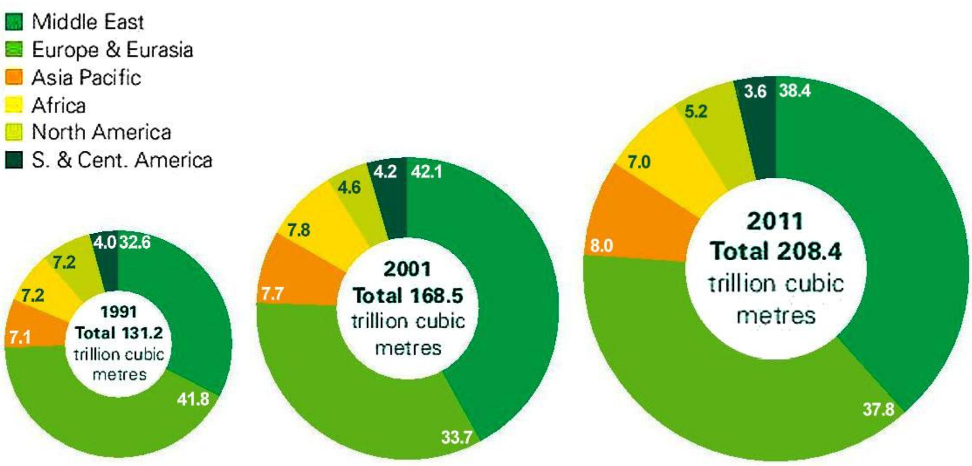

Figure 1.2 - Distribution of proved gas sources in 1991, 2001 and 2011 (source: BP, 2012)

Nevertheless, the global demand for natural gas (market expansion) has not kept up with the source discoveries. There exist considerable volumes, discovered over the past two decades, which have no immediately identifiable market (Ryan, 2004). These sources are known as ‘stranded gas’, and given their remote location and lack of economically feasible transport options cannot be exploited viably (Blikom and Danielsen, 2010).

Natural gas has been embraced by governmental policy makers as a favoured energy resource in recent years. A key reason for this is that only one-third of the world’s gas sources are in the politically unstable Middle East, whereas about two-thirds of the world’s oil reserves lie there (UBS, 2004).

Presently, the US and Russia are the biggest gas producers. Nevertheless, and due to high consumption, the US is a net-importer, while Russia is the biggest exporter (with about 180 bcm of export per annum) mostly through its pipelines to Europe (BP, 2012). Figure 1.3 shows the trade flows of natural gas in 2011. For a review of gas supply and demand see (Reymond, 2007).

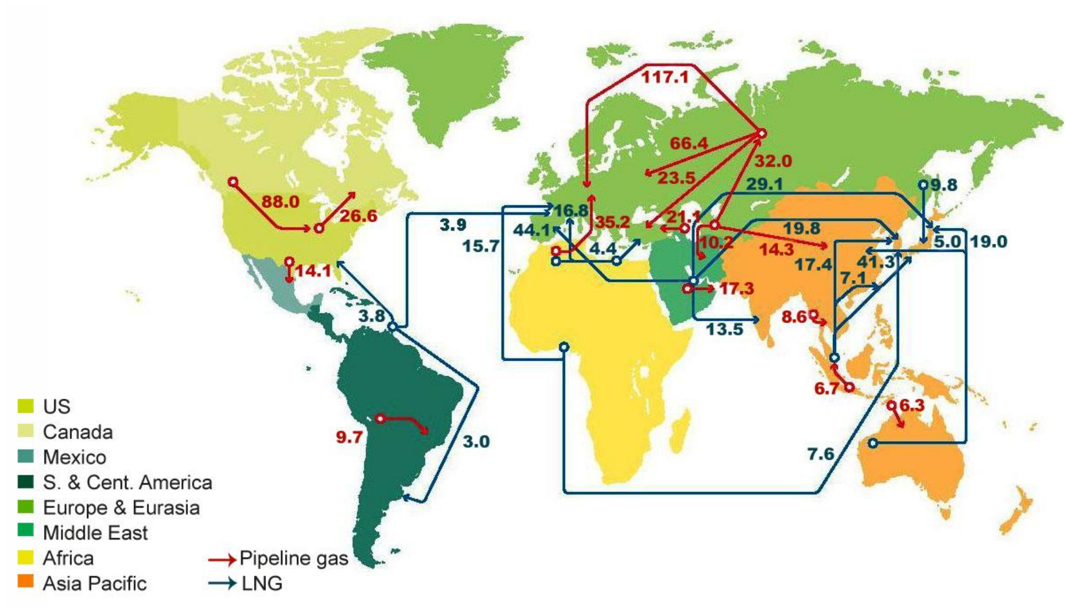

Figure 1.3 - Trade flows of natural gas (bcm), 2011 (source: BP, 2012)

1.1.2. Transport of natural gas and the rise of LNG

There are two ways of exporting gas internationally: using pipelines (for short distances) and in its liquid form known as LNG (for long distances). Generally, liquefying natural gas and shipping it via the ocean becomes cheaper in comparison to off-shore pipelines if the customer is farther than about 650 miles. This distance is about 2200 miles for on-shore pipelines (Figure 1.4).

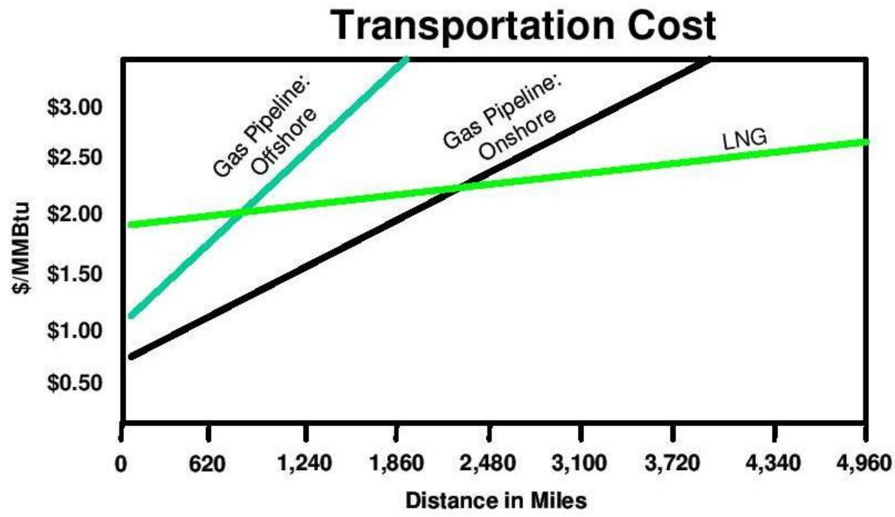

Figure 1.4 - Comparison of costs for transferring gas via pipeline and as LNG (source: MichotFoss, 2007)

LNG supplied about 10% of world gas demand in 2010, and its importance is increasing as demand for it grows faster than for pipeline gas internationally (Flower, 2012)[1]. It is predicted that demand for LNG will grow at about 10% per year for the next 10 years (Kumar et al., 2011). Due to this growing importance, LNG is worthy of consideration, hence, this research focuses on this form of natural gas.

1.2. Research problem statement

LNG is delivered through a supply chain that encompasses four phases: extraction, liquefaction, shipping and regasification (Figure 1.5). Of these phases, liquefaction and

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[1] Andy Flower has been working as an independent consultant for the last twelve years specialising in the LNG business. He retired from BP in 2001 after 32 years service, including 22 years working in the company's LNG and natural gas business units where he managed BP's interests in a number of LNG projects. Mr Flower is a senior research fellow in the Oxford Institute for Energy Studies (http://www.oxfordenergy.org/author/andy-flower/).

shipping are usually planned and managed by the same decision-maker (the LNG producer). This necessitates and generates an opportunity for using a combined management technique for these phases. Incorporating a combined decision-making process for liquefaction (an inventory management problem) and shipping (a fleet management problem) of LNG can reduce vessel management and inventory costs and, furthermore, can increase revenue from sales. This is a significant problem in the LNG industry, and has been selected as the focus of research in this thesis. This study concentrates on maximising the profit stemming from a combined LNG production (liquefaction) and distribution (shipping) project.

Figure 1.5 - LNG supply chain

Integrated decision-making in inventory and fleet management in running a business is a topic which has been studied extensively, especially in businesses such as retail (Bertazzi et al., 2002) and fuel distribution (Dror and Trudeau, 1996). This problem is referred to in scientific literature as IRP (see the glossary and abbreviations at the beginning of the thesis). It should be noted that in a combined inventory and fleet management of a system, if the general system design rather than the decisions on running the established system is meant, the problem is called SIRP (Larson, 1988, Webb and Larson, 1995).

Due to the magnitude of cost and revenue cash flows in the LNG business, a factor which can be important in decision-making and profit maximization in the project is the time value of money. This factor has been proven (see Hartmann and Briskorn, 2010) to be important in the decision-making of projects in construction management, where as for an LNG project, there are decisions to be made in managing the projects and relative to these decisions there are costs and revenues. Consideration of the time value of money has produced a new schedule for these projects and has changed their profit in a meaningful way. The aforementioned problem in construction management literature is named RCPSP for present value maximization. Despite similarities, the RCPSP and IRP are different problems and are applied to different contexts (construction management and transport operations, respectively). The time value of money in IRPs has not been considered before, and in this thesis, it is taken into account and its importance to the research problem is evaluated.

1.3. Research aims and objectives

Given the research problem discussed in the last section, the purpose of this study is to develop a model for profit maximization in LNG production and distribution. The objectives of the thesis are to:

(1) Investigate the LNG industry with the goal of understanding the nature of the LNG business including the ways and tools through which LNG is traded.

(2) Develop an operational model for the LNG research problem with the aim of profit maximization. Synchronized LNG production and distribution is an area of research that has previously been examined in the works of Halvorsen-Weare and Fagerholt (2013) and Rakke et al. (2011). In these works the researchers design an ADP – an annual programme for LNG deliveries – for the LNG project. But something that is missing from this research context is to deal with the operational difficulties or the business opportunities that arise during the daily running of the LNG project. In response, in this thesis an operational model (this

is a different type of plan) for the LNG problem is suggested. Before model development, a survey of the IRPs should be carried out.

(3) Derive practical insights for the LNG business. This is carried out given the model developed by sensitivity tests and analyses.

1.4. Thesis outline

To achieve the aforementioned objectives, this thesis is designed and presented in six chapters. Chapter 1 sets the pretext and provides a general understanding of natural gas, its history, deposits and the market. Furthermore, this chapter establishes the importance of LNG in world demand for natural gas and discusses the research problem and objectives.

Providing a proper understanding of the LNG business with is the aim of Chapter 2. In this chapter, after an introduction to LNG, its supply chain is discussed in detail then the LNG trade is considered. Firstly, the traditional LNG trade is considered; secondly, the state of LNG business for liberalized gas markets is studied; thirdly, the spot sale of LNG is considered; fourthly, pricing of LNG is assessed and finally, some numbers and statistics with regards to LNG business are provided. This business study which addresses objective (1) of the research provides the background base for model development.

Chapter 3 centres on studying the IRPs. In covering the IRPs we focus on previous studies with applications in the maritime sector. This is a reasonable choice since the research problem in this thesis is maritime in nature; hence, application of the IRP in the maritime context is important.

The MIP model for simultaneous LNG production and distribution, given the studies of Chapters 2 and 3, is presented in Chapter 4. This chapter initially establishes the link between the LNG business and the IRP model, and then the LNG problem of the research and the costs and revenues of the system are discussed. Finally, the problem is formulated for profit maximization. The work within Chapters 3 and 4 satisfies research objective (2).

Chapter 5 analyses various aspects of the LNG business. In this chapter, given several numerical tests using the model developed and based on an industrial case, the importance of cargo arbitrage and time value of money in profit maximization in an LNG project is assessed. The chapter also considers, through a number of tests, the significance of spot price fluctuation and also concurrent spot price and interest rate variations on decision-making for spot sales of uncommitted product in a project. At the end of the chapter, a mathematical analysis for the model response to simultaneous variations in the price and interest rate in spot sales of uncommitted product is provided.

Lastly, Chapter 6 outlines the practical research findings based on the numerical tests of previous chapter and fulfils objective (3). Further research suggestions conclude this chapter and the dissertation.

Chapter 2

Overview of the LNG Business

2.1. Introduction

LNG global trade has grown from about 25 MT in 1980 to about 240 MT in 2011 (Figure 2.1). It is predicted that, given the maturity of oil fields, LNG is going to be one of the main substitutes to oil in the new century, since like oil it can be dispatched to any destination in a tanker provided that the infrastructure is available (Kumar et al., 2011).

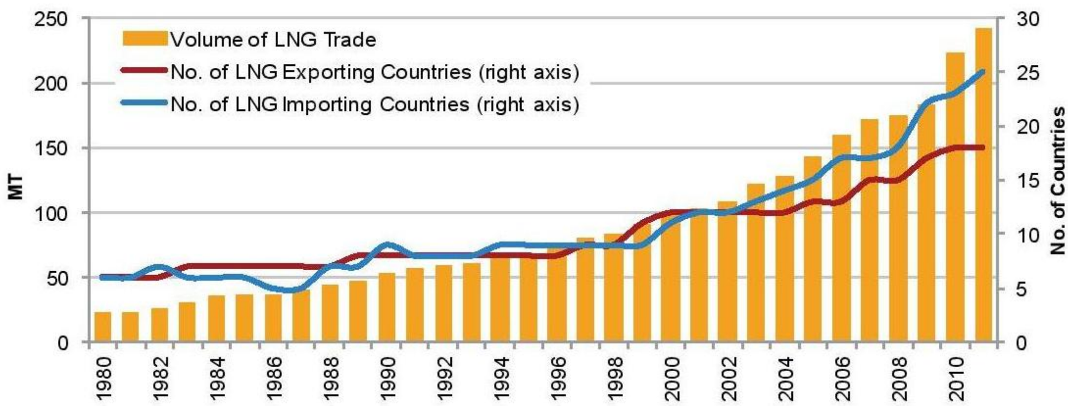


Figure 2.1 - LNG trade volumes (MT), 1980-2011 (source: IGU, 2012)

The LNG picture is very dynamic and is growing such that Qatar, a tiny country in the Persian Gulf, which exported its first LNG cargo in 1997, overtook all its rivals and became the biggest LNG exporter of the world in 2006. Qatar now accounts for more than a quarter of the world's LNG supply. But the story does not end there; Australia has made some very serious investments in its gas industry and expects to take the dominant role in LNG supply in the future (IEA, 2009).

To develop the project being considered in Chapter 1, detailed knowledge of LNG and its business, such as was discussed in the introduction, is needed. Thus, in this chapter LNG is introduced (2.2), its supply chain is discussed (2.3), and the LNG business is covered

(2.4). Knowing the LNG sector with its features and limits paves the way for modelling the research problem.

2.2. What is LNG?

LNG is the dense form of natural gas which has been cooled to the temperature of approximately -160 degrees Celsius and its volume decreased to 1/600th of the primary gas. LNG is a clear liquid with about 45 percent the density of water (Thomas and Dawe, 2003). Due to its decreased volume, huge amounts of natural gas can be kept in special isolated tanks or shipped in LNG tankers (Tusiani and Shearer, 2007).

Natural gas, in addition to methane is composed of ethane, propane and other heavier alkanes. Small quantities of water, mercury, carbon dioxide, nitrogen, oxygen and sulphur compounds may also be found in natural gas (Lee, 2005). In producing LNG, impurities such as water, carbon dioxide and NGL are largely removed in order to prevent formation of solids in the cooling process; these solids can damage the cooling equipment. Both NGL and some of the impurities after processing are sold as by-products. As a result of this removal, LNG is comprised mostly of methane (MichotFoss, 2007).

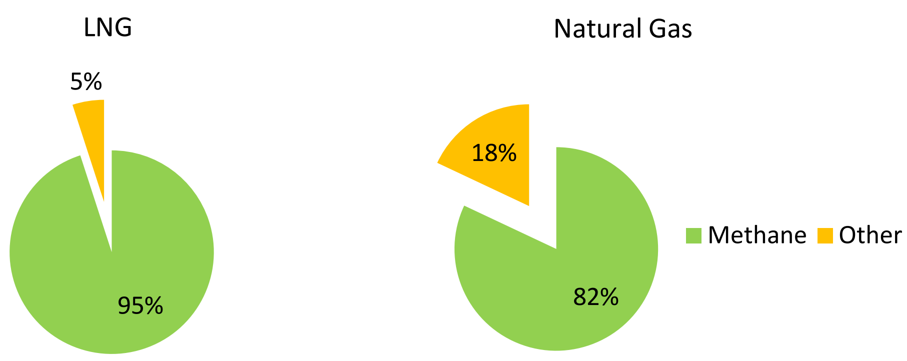


Figure 2.2 - Typical natural gas and LNG composition (source: MichotFoss, 2007)

2.3. What is the LNG supply chain?

There are four main stages in LNG supply, including: extraction, liquefaction, shipping and regasification (Enobun, 2008); Figure 2.3 depicts these phases plus the chain's main by-products.

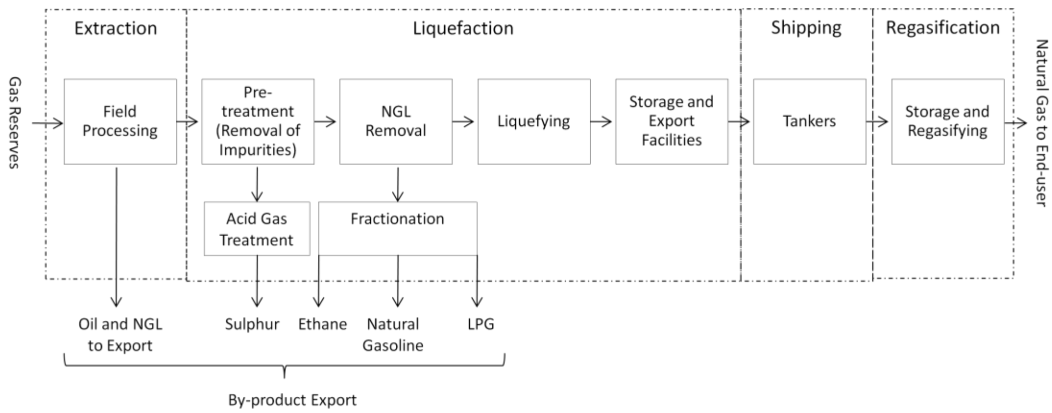


Figure 2.3 - LNG supply chain in detail

2.3.1. Extraction

The first phase of the LNG supply chain is extraction. In this phase gas is extracted from sea (sometimes land) sources and transferred to the LNG liquefaction plant usually via a pipeline. It should be said that at the well head, NGL (which is liquid at normal pressure) and oil (in the case of an associated gas reserve) are separated from natural gas. Further processing for the removal of impurities and the rest of the NGL dissolved in the gas – as discussed in 2.2 – occurs in the liquefaction phase (Lee, 2005).

Of course, prior to extraction, a viable gas source should be found and explored for development. In gas source exploration a drilling region is chosen, funds are secured and the test wells are drilled. Exploration is a risky activity since it might result in a dry hole (no natural gas) or a non-commercial gas reserve (the volume of the reserve or the subsurface conditions do not yield a field which can be developed as a commercial proposition) (MichotFoss, 2007).

2.3.2. Liquefaction

The liquefying process is carried out by the use of refrigerants in heat exchangers in the liquefaction plant (Shukri, 2004). Figure 2.4 is the flow diagram of a plant.

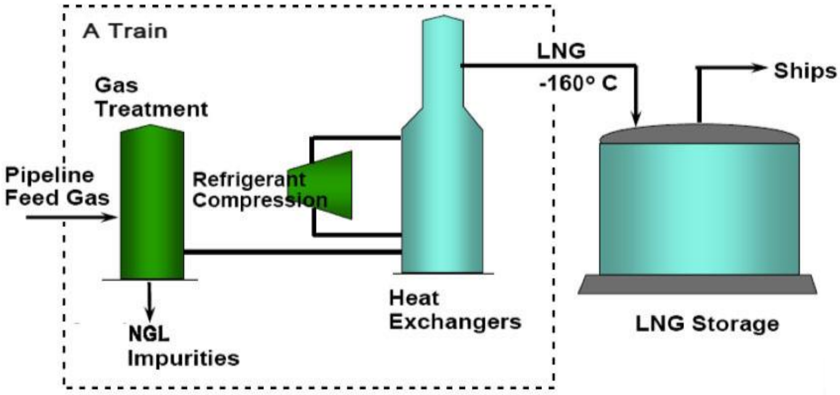


Figure 2.4 - Flow diagram of a liquefaction plant (adapted from: http://bit.ly/144eHTe)

Usually the plant consists of several parallel units, each one called a 'Train'. In a Train the removal process plus the liquefying of gas occurs (Lee, 2005). Figure 2.5 is a LNG liquefaction plant.

Figure 2.5 - The Atlantic liquefaction plant at Trinidad and Tobago in 2012 (adapted from: http://bit.ly/13B5Ibz)

At both liquefaction and receiving terminals LNG is stored in double-walled tanks at atmospheric pressure; the space between the two walls is filled with insulation. The inner tank is constructed with materials which are appropriate for very cold temperatures (-160 degree of Celsius) and the structural loading of LNG, materials such as nine percent nickel steel, aluminium and pre-stressed concrete. The outer wall is made of carbon steel and pre-stressed concrete (MichotFoss, 2007).

2.3.3. Shipping

LNG tankers are double-hulled ships which are supposed to prevent leakage and rupture in the event of an accident. The LNG is kept in the inner tanker at atmospheric pressure and at -160 degrees Celsius (Tusiani and Shearer, 2007). There are two main types of tanker design:

Membrane tankers: this type of tanker is supported by the hold it occupies. “Membrane tankers are composed of a layer of metal (primary barrier), a layer of insulation, another liquid-proof layer, and another layer of insulation. These several layers are then attached to the walls of the externally framed hold. Usually the primary and secondary barriers are sheets of Invar, an alloy of 36-percent nickel steel. Unlike regular steel, Invar hardly fractures upon cooling. The insulation layers are plywood boxes holding Perlite, a glassy material” (Global Security, 2012).

Spherical tankers: “a large spherical tanker, the first type of self supporting tank, is often what people visualize when a LNG carrier is mentioned. The early sphere designs were shells of 9-percent nickel steel. Subsequently, aluminum was used. The sphere is installed in its own hold of a double-hulled ship, so that it is supported around its equator by a steel cylinder (called a skirt). The covered insulation surrounding the sphere can channel any leakage to a drip tray located under the sphere's South Pole" (Global Security, 2012).

Previously most LNG tankers were of spherical design, but during the last decade the trend has been towards membrane tankers, and currently these tankers are making the biggest group of tankers number wise (this is seen later in Figure 2.21, 2.4.5, where an analysis of LNG carriers is carried out). This is most likely due to the fact that membrane tankers utilize the hull shape more efficiently and have less void space between the cargo tanks and ballast tanks. As a result of this, spherical tankers compared to a membrane design of equal capacity will be more expensive to take through the Suez Canal. The LNG tankers are generally less polluting than other ships because they burn natural gas as part of their fuel (MichotFoss, 2007).

2.3.4. Regasification

At the destination/receiving terminal, via a warming process the liquid is transformed back into gas (by the vaporizers), and the gas is pumped into the gas pipeline to be used in power plants or reach the commercial and residential consumers (Lee, 2005). Figure 2.6 depicts the flow diagram in a regas terminal.

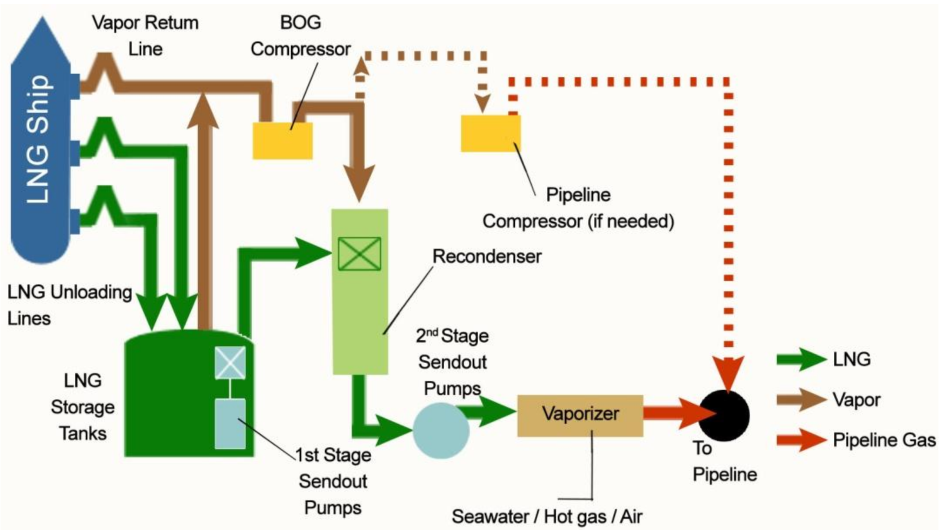


Figure 2.6 - The flow diagram of a regas terminal

An alternative to the onshore LNG regas terminal is a purpose built or specially converted vessel that operates as a floating LNG receiving unit/vessel. This type of vessel is called a FSRU (see the table of glossary and abbreviations). In a FSRU the ship tanks provide the storage while the regasifiers are installed on the deck of the ship; the gas is then delivered to the pipelines (Golar LNG Energy, 2011). A FSRU could be moored along a jetty in a port or moored offshore and connected to shore via a pipeline (Höegh LNG, 2012). A FSRU can alternatively serve as a normal tanker (IGU, 2012).

A FSRU in comparison to a LNG regas terminal has some advantages and disadvantages (Golar LNG Energy, 2011, Höegh LNG, 2012, Flower, 2012). On one hand the advantages are:

- Low capital cost ($100 million to $250 million) in comparison to onshore terminals (see Table 2.1).
- Faster implementation, as short as 12 months for design, permission and construction compared with 5+ years for an onshore terminal.
- Low environmental impact.
- Well suited to seasonal markets since it is possible to find alternative employment for the vessel and move it when gas demand is low.

On the other hand the disadvantages of FSRUs are:

- Chartering FSRUs is very expensive.
- Throughput is limited by the capacity of the onboard regasifiers (typically 400 to 500 MMscf/d base-load with up to 700 MMscf/d peak load) and the storage capacity.

- The FSRU has a similar capacity to the ship delivering the LNG, so managing stocks on FSRUs is more difficult than for an onshore terminal, which can usually store at least two ship-loads of LNG.

- No back-up in case of a delay in delivery of the LNG.

2.4. LNG business

Providing an understanding of the LNG business is the goal of this section. The section starts by defining LTCs and the traditional LNG business (2.4.1), continues by discussing the effect of liberalization on LTCs (2.4.2), then considers the spot sale in arbitrage and for uncommitted product (2.4.3), provides an understanding of LNG pricing (2.4.4) and finally provides some numbers and statistics on the LNG sector (2.4.5). It is to be noted that this research is developed around a problem for the producer (the entity that manages the production and distribution of LNG), hence it is the focus of the discussion in this section.

2.4.1. Long-term contracts and the traditional LNG business

The LNG business has been based, since its beginning, on LTCs. The duration of these contracts has traditionally been between 20 and 25 years, as the repayment of the loans takes 10 to 12 years (Maxwell, 2007). Traditionally, each contract has two sides, a producer (also known as seller in the industry) and a buyer (also known as buyer or customer in LNG sector). Figure 2.7 shows the relationship between different parties in a LNG project, which is LTC based from the perspective of the producer.

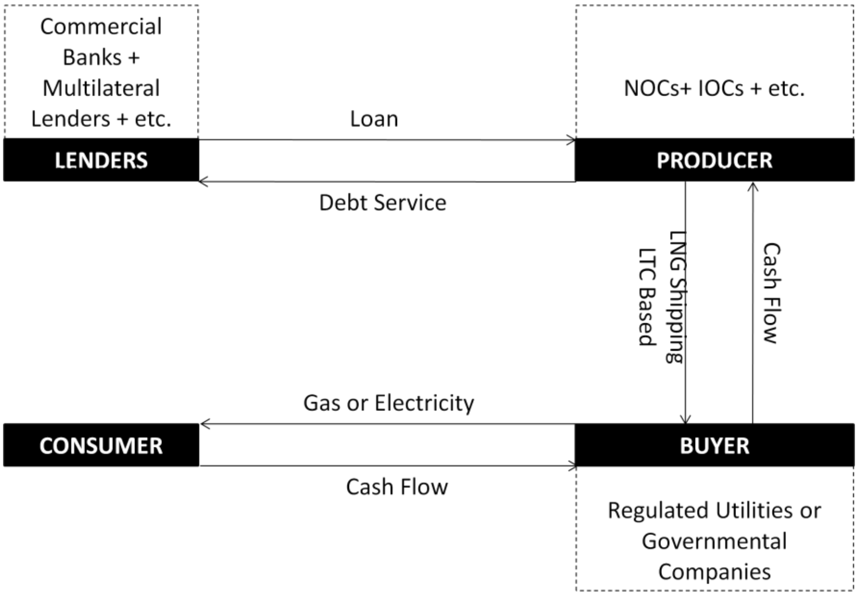


Figure 2.7 - Structure of a LNG project, LTC based

In such an arrangement, on the producer side, after finding a gas field and making sure that it is commercially viable (large enough to support the LTCs for the whole duration of the project and is predicted to return the capital expenditure with profit), a group of companies and institutes usually including commercial banks, multilateral lenders (e.g. EBRD), NOC of the supply country and IOCs finance the project (Taylor-DeJongh, 2004). While the loan providers do not become project owners, equity investors are the shareholders (sponsors) of the project and, as a venture (i.e. project company), make the producer part of the LTC. The project company, which is accountable for the project, sells the product and manages the project (usually one of the partners runs the operations for the venture) (Jensen and Dickel, 2009). The sponsors sometimes raise capital by issuing bonds for the project too (Sato, 2000). The buyer is on the other side of a LTC. These companies have traditionally been regulated utilities or governmental companies with monopoly markets from a developed country (Maxwell, 2007).

In traditional LNG trade, of the supply phases, the producer is responsible for establishing the upstream facilities, including the extraction facilities and the

6liquefaction terminal; the buyer provides the downstream facility, i.e. the regas terminal (Lee, 2005).

Tankers for shipping might be owned by the buyer, producer, both or a third party. They can be managed by either the producer or the buyer depending on the contract type. LNG can be delivered by the producer to the tankers managed by the buyer in liquefaction plants (FOB contracts) or it can be delivered to the regas terminal of the buyer (CIF/DES contracts) by the tankers managed by the producer.

The core of a LNG project, i.e. the LTC, is in fact a sale and purchase agreement that establishes the rights and obligations of the parties involved (Adegun, 2006). This agreement which helps in distributing the main risks, i.e. volume and price risks, between the buyers and the producers (the buyer takes the volume risk, while the seller takes the price risk; Enobun, 2008) has some features of which the most important are:

Commodity quality and quantity: the quality and quantity of LNG to be delivered is written into the contract. This clause also states what happens if one of these specifications is not fulfilled (Osiliko, 2005).

The destination clause: the LTC seeks to prohibit a buyer from selling, or procuring the sale of, the LNG which is to be delivered to the buyer at the principally identified unloading port, to any alternative unloading port in a CIF/DES based sale. Imposing the destination clause on CIF/DES contracts is easy and commonplace as the producer manages the transportation of LNG. While, for FOB contracts, in practice, as the buyer has control of the product on-board his tankers, enforcing this clause is extremely difficult and hence this clause is not commonly found in these contracts. It should be noted that destination clauses are effectively territorial restrictions, intended to preserve market separation for LNG producers (Roberts, 2011). Buyers are interested in

FOB contracts since it permits them to trade surplus LNG (what they do not use themselves) with other importers, but to protect themselves the producers have insisted on CIF/DES contracts, hence, FOB contracts have not been as commonplace as CIF/DES contracts in the LNG business (Chandra, 2006).

Take-or-pay provision: take-or-pay is a clause in the LTC that "entitles a buyer to take a minimum quantity of gas each year and obliges the buyer to pay for that minimum quantity whether or not this is actually taken" (Davey, 1997). Traditionally, more than 90% of the annual production of liquefaction plants has been sold under this clause and the remainder (uncommitted product to LTCs) sold on spot (Jensen, 2004).

Price: price is an important factor in securing the revenue of a LNG project. LTCs do not usually have a fixed price over the life of the contract, but rather they have a formula which relates the price of cargos to competitive fuels at the time of delivery to the destination, with sometimes a minimum price to protect the producer from a complete collapse in prices (Abdulkarim, 2008).

The philosophy of having the LTC, given its features, in capital intensive projects like LNG (Table 2.1 gives costs of a chain) is that the project sponsors should persuade the lenders that their investment is secure. This persuasion is in the form of LTCs for the project. These contracts, given the take-or-pay provision, assure that there is a minimum steady income for the producer (the lenders consider the projects very conservatively) using which he can do his debt service and pay the operating cost (in order to keep the project running and generating revenue) (Greenwald, 2006). In fact, during the negotiations between the sponsors and the lenders, lenders ask for a LTC and also a transport agreement (proof of having sufficient vessels for transferring LNG between the two sides) before giving a 'go ahead' to the project (Abdulkarim, 2008).

Table 2.1 - Costs of an 8mtpa LNG supply chain (source: Flower, 2012)

Activity	Capital expenditure in billion dollars
Field development and extraction	2-6
Liquefaction plant	6-10
Shipping	1-2.5
Regasification terminal	1-1.5
Total	10-20

Even after providing these agreements, the upstream lenders usually also evaluate the credit worthiness of the buyers. This is because, even with a take-or-pay provision, if the buyer cannot fulfil his obligations the producer and consequentially the lenders face cash-flow problems (Radetzki, 1999). It should be mentioned here that lenders are not only concerned about cash flow security but also consider risks such as political risks (i.e. stability of the host country, reliability of its legal and regulatory systems and policies, etc.) before finalizing their decision (Razavi, 1996).

2.4.2. Gas market liberalization and its implication for long-term contracts

One of the goals pursued by many governments as part of their energy policy agenda is opening their gas markets, which are characterised by monopolies, through liberalization. The outcome of liberalization is the introduction of competition to the market (Omorhirhi, 2006). Liberalization of the markets has provided third-party-access by regulation to the gas transmission and distribution facilities in the US and Europe which in the LNG industry would be the regas terminal[1] (King & Spalding, 2004). In brief, with third-party-access, infrastructure owners must grant access to third-parties with regulated tariffs/cost-of-services on transparent and non-discriminatory terms when capacity is available; the unbundling of the infrastructure might also be imposed (Flower, 2012). “The open market policy crept into the LNG market to forestall the monopolistic power of the LNG buyers” in the US and Europe (Enobun, 2008). It should

[1] There is third-party-access to peak shaving LNG facilities too, but they are not part of the LNG supply chain, hence, not the concern of this research.

be stated that there have been three main different regions in marketing LNG: Asia (that is traditionally Northeast Asia and more recently India and China), Europe (including the continent and the UK) and North America, i.e. the US (Dickel et al., 2007). The US and UK are mature liberalized markets while the liberalization process in Continental Europe continues. Asian LNG markets are still far from having a liberalized gas market (IEA, 2012).

In both the US and Europe, infrastructure owners can seek relief from mandatory third-party-access on all or part of the capacity, and reserve the capacity for themselves (as in for example the South Hook LNG terminal, UK) or sell it on negotiated terms and prices (in many cases on long-terms, for example in the Grain LNG terminal, UK)[1]. This has happened to many new regas terminals (King & Spalding, 2004). Today, in Europe, the national regulatory authorities (e.g. OFGEM in the UK) given the Third Energy Package Gas Directive/Directive 2009/73/EC (EC, 2009) and its Article 36 can grant the exemption. In the US, FERC, given the Hackberry Decision (2002) can grant relief (to our knowledge FERC has not called for any mandatory third-party-access since 2002, hence this type of access is pretty limited in the US). The exemptions in the US and Europe aim at encouraging investment for building new and upgraded infrastructure (Dickel et al., 2008).

It should be noted that third-party-access does not necessarily prevent long-term booking of capacity in terminals such that many LNG terminals, subject to open access in Europe, have their capacities fully or largely booked/contracted on a long-term basis (as in for example the Zeebrugge LNG terminal, Belgium). Of course there is also short-term capacity for booking available in some terminals (as in for example the Adriatic LNG

[1] The exemption of the terminals mentioned was based on Directive 2003/55/EC. This Directive was repealed later by Directive 2009/73/EC.

terminal, Italy), for the market players to utilize short-term trading opportunities. In general worldwide, for terminals subject to third-party-access, the unused booked capacity should be released to be used by other market participants. Also, for the exempted terminals, the unused capacity should be made available to others through some measures. For a review of the regas terminals, their capacity, access arrangements and measures, in Europe, which could be different in various countries, see CEER (2013). Jensen and Dickel (2009) provide a perspective on regas terminal arrangements in the US.

It was mentioned in the previous section that the regas terminals in traditional LNG business are built by the buyers (for the buyer's sole use). However, in the US and Europe there has been a movement away from this model. In these markets, it is observed that regas terminals are built by transmission companies, totally unbundled from any marketing activities. They usually sell the capacity on a long-term basis to other companies with marketing activities (as is the case for example in the Gate LNG terminal, Netherlands). Also, regas terminals are built by the buyer partner in self-contracts (this is discussed later) for accessing the markets (for example the South Hook LNG terminal, UK) (IEA, 2012).

As the result of liberalization and competition in the gas markets, there is considerable pressure to make LNG contracting more flexible, but producers have shown a great unwillingness to develop a new project without proper LTC protection. Thus, the industry is expected to keep relying on LTCs and this would act as the filter that determines the flow of new projects into the market (Dickel et al., 2007).

Particularly in the US and UK with their fully liberalized gas markets, LNG buyers are now smaller and much more sensitive to price competition as their monopoly position has now been eliminated. In liberalized markets where companies are exposed to increasing volatility in gas prices (Abdulkarim, 2008), most buyers cannot assume a volume risk without a market-responsive pricing clause. Thus, the producers are more directly exposed to price risk than they were traditionally (Jensen, 2004). With such an arrangement, "since the buyer can so easily resell unwanted volumes in the liquid spot market with limited financial loss, his risk has been significantly reduced. Risk has thus migrated upstream ..." (Jensen and Dickel, 2009). The reaction of the producers to this has increasingly been towards self-contracting.

In self-contracting, (the marketing affiliate of) one (or more) of the partners in the venture signs the LTC with the venture/producer, becomes the LNG buyer and is responsible for marketing the product (Jensen and Dickel, 2009); with CIF/DES deliveries with a very relaxed destination clause which permits easy change of destination; here, according to the contract, in changing the destination, approval is not to be unreasonably withheld by the producer (Flower, 2012). Given the relaxed destination clause, the market destinations for cargos resulting from self-contracts are defined by the best netbacks available to the buyer partner (in effect the producer since there are rent sharing mechanisms in arbitrage – this is discussed in the next subsection), given the regas terminals available to this partner (built or booked in the US and Europe), or on occasions demand from other regasification capacity holders in the LNG market. This means in many cases in self-contracts, sales are not going on according to the contract and cargos are not delivered to the principally identified regas terminal for the contract. In the US and the UK, where spot markets dominate the onshore gas trade, self-contracting permits the buyer partner to participate in the market, and this type of contract is very important in these countries. Traditional LTCs[1] remain important on the European Continent (with many buyers on these contracts having booked long-term

[1] In a traditional LTC, as in Figure 2.8, the contract is between the producer and specific customers. While, in self-contracts, the buyer partner – and in a way the producer through it – acts as a wholesaler to the market (Dickel et al., 2007).

capacities on the regas terminals) and stay the dominant type of contract in Asia (Dickel et al., 2007). Self-contracting permits the buyer partner to sell the gas to smaller re-sellers (e.g. utilities) or directly to consumers in liberalizing/liberalized markets (Dickel et al., 2008). See Figure 2.8 for a comparison of self-contracts and traditional LTCs.

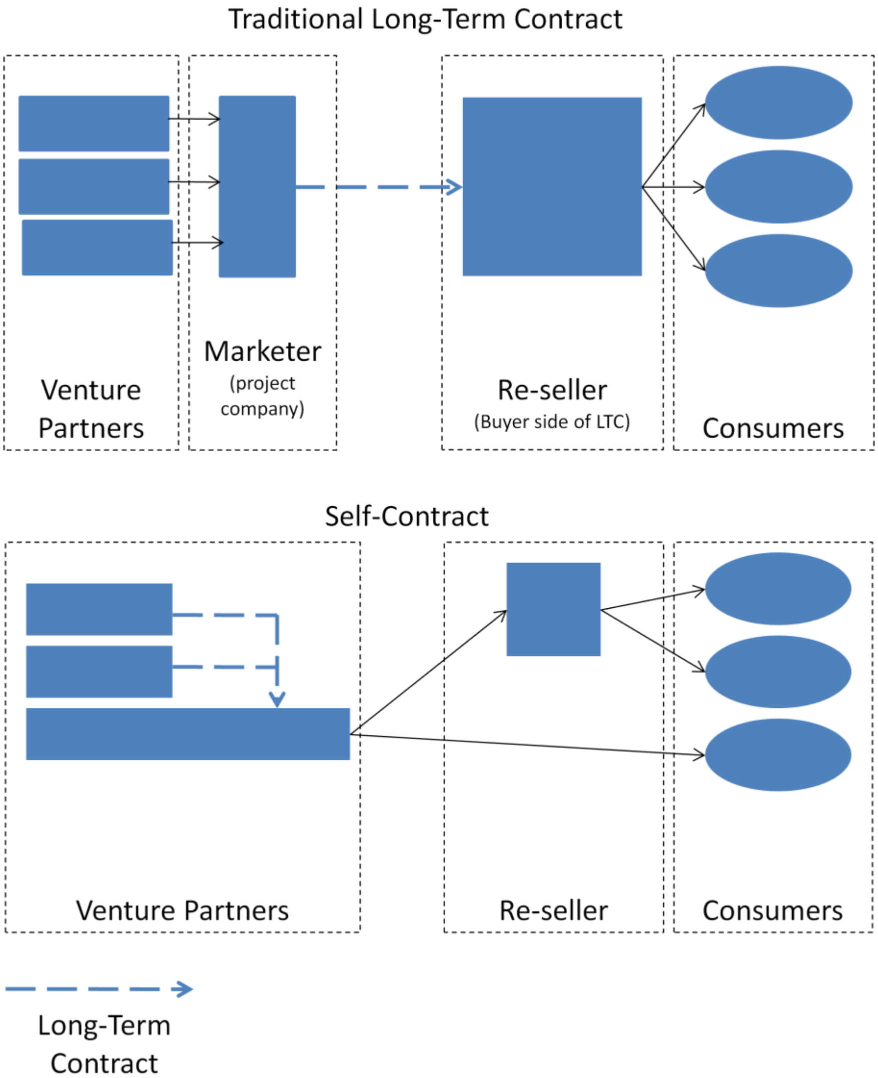


Figure 2.8 - The traditional LTC and the new self-contracts (source: Dickel et al., 2007)

Speaking of LTCs and relevant markets it should be said that due to the surge of shale gas in the US, the import of LNG to this country has decreased and cargos have been arbitraged to Europe and Asia since a few years ago. It is interesting to note that as a result, there is an oversupply of LNG to the market, due to which new traditional LTCs are shorter than before, 10-20 years (Argus Global LNG, 2011).

Dividing the supply sources of the world into the Pacific Basin, Middle East and Atlantic Basin (the LNG exporters are discussed in 2.4.5), the self-contracts are sourced from the Atlantic Basin and Middle East. In 2008 about 15% of world LNG supply was done on self-contracts and about 75% on traditional LTCs. (Jensen and Dickel, 2009). Traditional LTCs are still the main type of contract in place in the LNG industry.

It should be mentioned that other than the main arrangements explained in this section and the previous one in selling and supplying LNG (traditional LTCs with CIF/DES and FOB deliveries and self-contracts with CIF/DES deliveries), there are other arrangements in place in the market too. For example, the tolling arrangement, where a commitment is made to capacity of the liquefaction plant to liquefy gas produced by gas producers. In this model the project company (the liquefaction plant venture) provides a service to gas producers. It does not own the gas entering the plant or the LNG produced. The users commit to capacity and pay a liquefaction fee, they deliver gas to the plant and take an equivalent volume of LNG produced by it (Jensen and Dickel, 2009). But to our knowledge such arrangements are specific, hence are not the focus of this study and model development.

2.4.3. Spot sale of LNG for uncommitted product and in arbitrage

It is interesting to note that spot sale occurring OTC in the LNG sector consists of two kinds of sale: genuine spot sales and, on occasions, short-term. In short-term sales, there is a series of LNG cargo sales based on a short-term contract with often a duration of less than one year rather than a single cargo sale (Jensen, 2003). The main features of these short-term sales (contracts) according to Abdulkarim (2008) are:

- Take-or-pay obligation: although it might still exist in the contract, it does not cover the volume risk over the life of the loan provided by the lenders.

- Fixed price: the price in this type of contracts might be fixed. There is no point for time dependent prices especially for very short ones.

The importance of spot sales in the LNG sector has grown over the years. Figure 2.9 shows the growth of spot sale volumes and its share of the total LNG trade between 1985 and 2011.

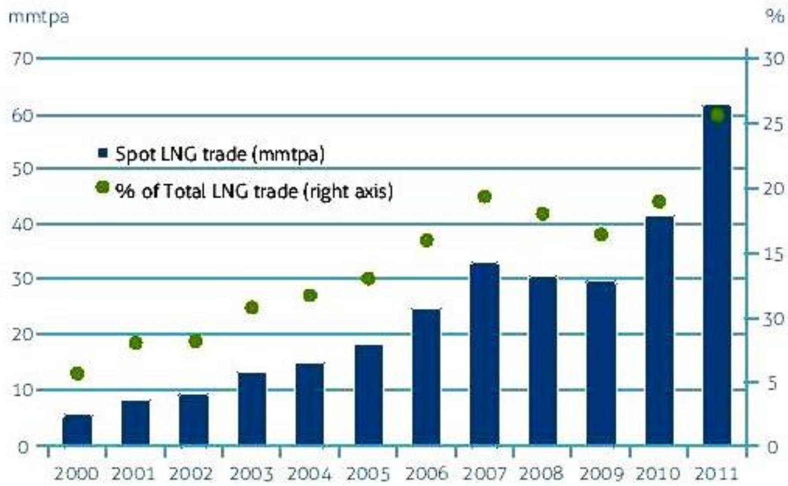


Figure 2.9 - Volume of spot LNG trade and its share of total LNG trade (mmtpa), 1995-2011 (source: GIIGNL, 2012)

In 2011, the main exporters active in LNG spot supply have been Egypt, Nigeria, Peru, Trinidad and Tobago, Indonesia and, in particular, Qatar; while the main importers have been Spain, UK, India and, particularly, Taiwan, Japan and South Korea. More than half of the 61 (MT) spot LNG trade in 2011 was absorbed in Northeast Asia, then China and India (GIIGNL, 2012). Japan was the biggest spot LNG importer in 2011, with 16 MT of spot imports, in the wake of Fukushima nuclear crisis and the resulting need for replacing nuclear power supply (IGU, 2012). In general and over time, Northeast Asia has been a primary market for LNG spot cargos (Rogers, 2010).

There are two main types of spot sale, both involving the LNG producer: the spot sale of uncommitted product (the LNG product of liquefaction plants that is not sold on LTCs) and arbitrage (in traditional LTCs and self-contracts). There are spot sales that do not involve the producer, for example, re-exports (discussed in 2.4.5) but to our knowledge those are not as important as the aforementioned and not the concern of this research. With regard to uncommitted product spot sales by the producer, it should be stated that the sources for these sales are (Jensen, 2004):

- Extra capacity of liquefaction plants during the ramp-up period of the projects. The ramp-up period is the period between the start of production to the time that the long-term buyers develop their business and can take all their contracted LNG.
- The increased capacity of the old projects.
- The old projects once their LTCs are expired.
- A proportion of the LNG project that is uncommitted and dedicated to spot sales.

The uncommitted proportion of product in an established project, which is usually delivered by producers to regas terminals in a spot sale (in thesis it is always delivered by the producer), has been as high as 10% of annual output although in some new projects it is higher and can be as much as 20% (Flower, 2010).

Over the past few years it has become an acceptable industry practice for the LNG cargos on LTCs with predefined destinations to be diverted to other markets and sold on spot with mutual agreement of LTC sides, i.e. the producer and buyer (as discussed this is facilitated in self-contracts, but even happens in traditional LTCs) (Yegorov and Dehnavi, 2012).

By definition LNG arbitrage is the diversion of the physical cargo from one market (regas terminal) to another. The diversion of the cargo can be considered arbitrage, if the cargo was initially committed to the first market in a commercial contract (Zhuravleva, 2009). Given the definition of arbitrage, it finds a meaning when the deliveries are of CIF/DES type (there is a destination clause in the LTC). For LTCs with FOB deliveries, the cargos are not committed to any market as these contracts almost always do not have any destination clause, and arbitrage cannot be defined. In Traditional LTCs with FOB deliveries, defined as one of the main ways of selling LNG in previous sections, the buyer may sell the surplus LNG on spot and without any rent sharing.

The drivers for arbitrage are commercial and operational. The arbitrage with commercial incentive occurs due the regional structure of the LNG market and the price differences among the regions. Such price differences encourage the cargo diversion for the purpose of higher profits. The cargo arbitrage with operational incentives in the LNG business may take place due to the reasons such as regas terminal outages, overfull storage tanks, unrests, embargos and conflicts. Here, the driver of arbitrage is not a higher profit rather the circumstances enforce the arbitrage (Anyanwu, 2010). The margin of arbitrage with an agreement is distributed between the main parties involved in the cargo diversion. Three distinct varieties of arbitrage can be defined from the producer's point of view according to Zhuravleva (2009):

The producer as the arbitrageur: in this model of arbitrage the producer initiates the arbitrage and offers the cargo diversion to the buyer side of the LTC and shares the margin with him. The buyer may accept the arbitrage subject to replacement of the cargo. A case of this type of arbitrage happened in 2008. In March of that year Oman diverted a cargo to Asia with the cargo being primarily assigned to Spain with a traditional LTC.

The buyer as the arbitrageur: in this form of arbitrage the buyer decides to divert the cargo to another market. The incentive for this decision, for example, can be availability of cheaper gas in the local gas market of the buyer in traditional LTCs. The margin is divided between the producer and the buyer. This type of arbitrage often happens in Spain due to the limited storage capacity in this country.

An independent trader as the arbitrageur: an independent trader, such as a bank, buys the cargo or achieves the right to divert the cargo. This trader might need to replace the cargo for the buyer in the LTC. The independent trader would need to share the margin with the producer and the buyer.

The possibility of margin sharing of arbitrage with producer's in the cases of both CIF and DES deliveries is logical since the producer is responsible for facilitating the transportation, and without any motivation for him arbitrage would be difficult. But it is interesting to note that the European Commission, which does not like the destination clause, as it finds it to be anticompetitive, had an agreement with Sonatrach (the Algerian NOC, a main LNG seller to Europe) in 2007 according to which the destination clause was removed from Sonatrach LTCs, and this company retains a share of the margin in arbitrage when the contract is only of DES type. A slight difference between the DES and CIF contracts is that the title to the LNG on-board a tanker is transferred to the buyer when the boat is at sea for CIF contracts. While for DES contracts the title is transferred in the destination port. The European Commission, in its agreement with Sonatrach, does not believe in margin sharing in arbitrage with the producer when the title has been transferred to the buyer at sea and thinks Sonatrach does not have any right or say with regards to the decisions made on such LNG (Roberts, 2011). However, in principle for both CIF and DES contracts having a destination clause and margin sharing are common and are considered in this thesis.

2.4.4. LNG pricing

Pricing of LNG in various markets is different. Of the significant LNG markets; in Continental Europe and Northeast Asia, India and China the prices in LTCs are linked to rival energies. The prices of LNG in these markets are the result of negotiations between the buyers and the producers who want to get the highest possible netback for the depletion of their national resources. But in the UK and the US prices are determined by competition in the liberalized markets among different gas suppliers. It should be mentioned that forming an international LNG market is currently far from reality due to the regional formation of the business (Dickel et al., 2007).

Pricing of LNG in the US and Europe: there are two types of pricing in these markets. Pricing linked to gas market indicators, i.e. Henry Hub and NBP for the US and the UK, respectively, and for Continental Europe where the LNG price in LTCs is usually linked to oil or oil products depending on the country (Maxwell, 2007). On the continent, due to increasing competition from pipeline gas, the indexation pattern for LNG tends to follow the same structure as on-shore gas, with references to coal, electricity, etc. In general, the liberalization process on the continent is making LNG pricing more competitive (Davoust, 2008).

"While the NBP in the UK represents a single (and theoretical) transaction point, the North American market has many other transaction points (hubs) keyed to Henry Hub by 'basis differentials'. While these in theory approximate the costs of transportation between Henry Hub and the alternative hub, they can easily differ significantly depending on market conditions. The contracting[1] that has taken place for the US market appears to be on a netback basis ... . They thus feature a reference price, such as Henry Hub, and may include basis differentials if deliveries are made into a market

[1] Mainly self-contracts

served by one of the other market hubs. Prices may be adjusted monthly ..., or they may be adjusted more frequently based on either the daily quotation or on a several day average to dampen volatility" (Dickel et al., 2007).

LNG pricing in Northeast Asia, China and India: the importing of LNG to Japan began as a result of the electric utility industry. At that time (1960s) the Japanese electricity industry was based on oil, coal and hydropower, with heavy fuel oil and crude oil accounting for around 40% of generated power. In view of the fact that reducing oil imports was a main policy for the Japanese at that time, replacing oil with LNG in generating electricity became an important objective for them. Therefore, the competitive price target for LNG in Japan became oil (Jensen and Dickel, 2009).

The price formulas in Japanese LTCs primarily were tracking the oil prices in the market of the producers, but since 1987 nearly all Japanese contracts follow the Japanese Customs Clearing price for crude oil (JCC). Later when Taiwan and South Korea became active in the LNG market, they too adopted the JCC price escalation scheme; this scheme is now common in the entire South and East Asian region (Dickel et al., 2008). Currently exporters such as Indonesia, Malaysia and Qatar are among the biggest suppliers to the Asian LNG markets (Fujime, 2002).

The most common pricing formula in Asia is $P = A * JCC + B$. Here A is a coefficient which links the JCC price in $/bbl to the LNG price and B is a constant in $/MMBtu. The JCC price is published monthly but the LTCs usually average it over a period to dampen any fluctuations (Fujime, 2002).

The volatility in oil prices due to the crises in the oil market has encouraged buyers to ask for a cap in pricing the LNG in Asia; this means if the oil price goes over a specific value, the LNG price would be set as this cap. On the other hand, producers have asked for a floor for the LNG price to protect themselves against sharp falls in oil prices. The resulting scheme of pricing is called an S-curve (Davoust, 2008). Figure 2.10 is an S-curve with floor and cap at 15 $/bbl and 30 $/bbl, respectively, and an LNG price formulation of *price = 0.1485 * JCC + $0.80* (Dickel et al., 2007).

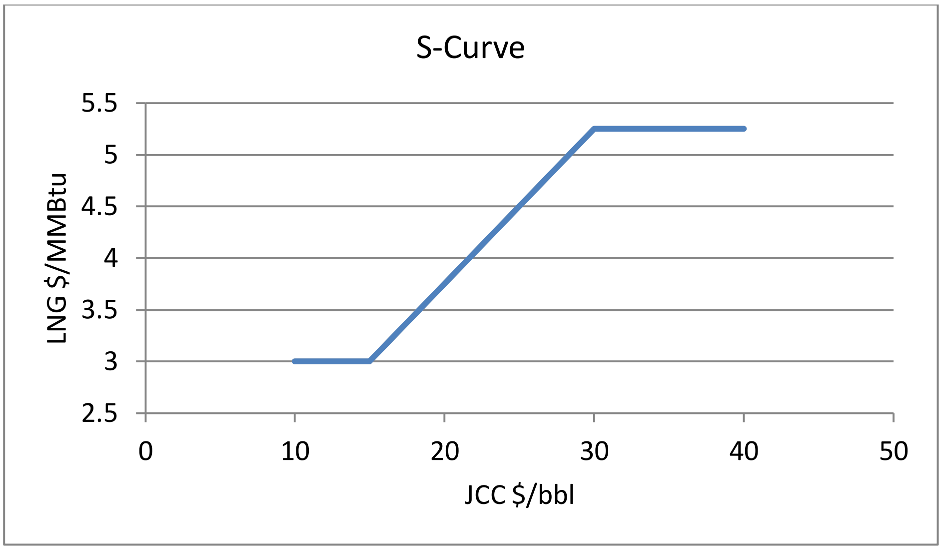


Figure 2.10 - A typical S-curve

In conclusion to this section, the LNG prices in Asia (particularly Northeast Asia) tend to be higher than in Europe and the US, as abundant pipeline gas supply in the US and Europe generally causes prices to be lower (Drewry, 2010). Table 2.2 provides the weighted average LTC prices of LNG imports to some of the markets between 2000 and 2009 (spot prices in Continental Europe and Asia where LTCs are not linked to any gas market indicator could be much higher or lower).

Table 2.2 - LNG Prices ($/MMBtu) (source: Drewry, 2010)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Europe*	3.09	3.54	3.14	3.63	3.89	5.1	6.62	6.42	9.63	n/a
Japan	4.73	4.64	4.32	4.82	5.23	6.04	7.18	7.8	12.51	9.05
South Korea	5.04	4.95	4.41	5.03	5.74	6.96	8.75	8.9	13.87	9.33
US	3.43	4.26	3.34	4.7	5.71	8.1	7.05	6.93	9.43	4.51

* Including UK

2.4.5. LNG sector, more numbers and statistics

In this subsection primarily LNG trade flows, volumes, origins and destinations are provided. Then, the current and future world liquefaction and regas capacity are established. Finally, a short discussion on LNG carriers is presented.

Trade flows, volumes, origins and destinations: in 2011 there were 18 LNG exporters in the world, see Table 2.3. In addition to that, five countries namely the US, Spain, Belgium, Brazil and Mexico were re-exporting LNG previously imported from another source. Of these five the US is also a normal exporter (GIIGNL, 2012). The re-exporting in the US, as aforementioned, is due to the rise of shale gas which has diminished the need for LNG and in Spain it is due to the tendency towards renewable sources of energy (IGU, 2012).

It is interesting to note that re-exporting is in fact a type of arbitrage that is carried out by the buyer (without involving the producer) where there is a destination clause in the LTC. Here, the buyer receives the LNG in the principally identified regas terminal in the LTC but as soon as the cargo is discharged to the tanks of the terminal it belongs to the buyer and the producer does not have any rights over it. Then the buyer loads the LNG to a tanker and dispatches it to a market with higher prices (Zhuravleva, 2009).

On the other hand there were 25 LNG importers in 2011 (GIIGNL, 2012). Table 2.3 presents the trade flows of LNG between different countries. Looking at the numbers in Table 2.3, it can be seen that Qatar supplies more than 30% of the world’s LNG. Qatar is followed by Malaysia, Indonesia, Australia and Nigeria. These countries together make more than 60% of world supply. Figure 2.11 shows the share of 18 world exporters in 2011 in total world LNG trade; the total trade according to Table 2.3 is about 241 MT.

Table 2.3 - LNG trade volumes between countries (MT), 2011 (source: GIIGNL, 2012)

Exporters \ Importers	Argentina	Belgium	Brazil	Canada	Chile	China	Dom Rep	France	Greece	India	Italy	Japan	Korea	Kuwait	Mexico	Netherlands	Portugal	Spain	Taiwan	Thailand	Turkey	UAE	UK	US *	Total
Algeria	-	0.06	-	-	-	-	-	4.23	0.72	0.18	1.16	0.06	-	-	-	0.06	0.06	2.94	-	-	2.96	-	0.18	-	12.61
Australia	-	-	-	-	-	3.71	-	-	-	0.04	-	13.69	1.16	0.19	-	-	-	-	0.34	-	-	0.06	-	-	19.19
Belgium	-	-	-	-	-	-	-	-	-	-	-	0.19	0.06	-	-	0.06	-	0.20	-	-	-	-	-	-	0.51
Brazil	0.04	-	-	-	-	-	-	-	-	-	-	-	-	0.06	-	-	-	-	-	-	-	-	-	-	0.10
Brunei	-	-	-	-	-	-	-	-	-	-	-	6.15	0.70	-	-	-	-	-	-	-	-	-	-	-	6.85
Egypt	0.06	-	-	-	0.06	0.21	-	0.65	0.06	0.51	0.38	0.67	0.50	0.05	-	-	0.06	1.73	0.04	-	0.26	-	0.06	0.73	6.03
Eq. Guinea	-	-	-	-	0.91	0.13	-	-	-	-	-	1.56	0.78	-	-	-	-	-	0.57	-	-	-	-	-	3.95
Indonesia	-	-	-	-	-	2.40	-	-	-	-	-	9.26	7.57	-	0.19	-	-	-	1.95	0.07	-	-	-	-	21.44
Libya	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.06	-	-	-	-	-	-	0.06
Malaysia	-	-	-	-	-	1.72	-	-	-	0.13	-	15.45	3.91	0,32	-	-	-	-	3.40	-	-	0.06	-	-	24.67
Mexico	-	-	-	-	0.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.06
Nigeria	0.30	0.06	0.05	-	-	0.67	-	2.66	0.06	1.00	-	1.90	1.13	0.59	0.86	0.05	1.91	4.74	0.67	0.12	0.92	0.06	0.88	0.05	18.68
Norway	-	-	-	-	-	-	0.06	0.39	-	0.06	0.12	0.18	0.30	-	-	0.06	0.06	0.93	0.12	-	-	-	0.26	0.31	2.85
Oman	-	-	-	-	-	-	-	-	-	0.13	-	3.98	3.55	-	-	-	0.13	0.13	-	-	-	-	-	-	7.92
Peru	-	-	-	-	-	0.15	-	-	-	-	-	0.34	0.74	-	0.49	-	1.43	0.06	0.22	-	-	-	-	0.34	3.77
Qatar	0.43	4.59	0.29	1.57	0.45	2.31	-	2.38	0.12	9.70	4.48	11.58	7.85	1.12	1.31	0.27	0.12	3.52	4.00	0.25	0.43	0.78	16.15	1.79	75.49
Russia	-	-	-	-	-	0.24	-	-	-	-	-	7.18	2.82	-	-	-	-	-	0.18	0.06	-	-	-	-	10.48
Spain	0.15	-	-	-	-	-	-	-	-	-	0.17	0.11	-	0.06	-	-	-	-	0.05	-	-	-	-	-	0.54
Trinidad	2.22	0.06	0.18	0.86	0.94	0.35	0.66	0.30	-	0.42	0.12	0.38	1.63	-	-	0.06	-	1.87	0.05	-	-	0.22	0.42	3.20	13.94
UAE	-	-	-	-	-	-	-	-	-	0.12	-	5.63	-	0.04	-	-	-	-	0.06	-	-	-	-	-	5.85
US	-	-	0.19	-	0.06	0.13	-	-	-	0.33	-	0.36	0.18	-	-	-	-	0.12	-	-	-	-	0.13	-	1.50
Yemen	-	0.21	-	-	0.31	0.75	-	0.13	-	0.13	-	0.13	2.94	-	0.13	-	-	-	0.14	-	-	-	0.54	1.24	6.65
Re-exports	-	-0.52	-0.09	-	-	-	-	-	-	-	-	-	-	-	-0.06	-	-	-0.55	-	-	-	-	-	-1.18	-2.40
Total	3.20	4.46	0.62	2.43	2.79	12.77	0.72	10.74	0.96	12.75	6.43	78.80	35.82	2.11	2.92	0.56	3.77	15.75	11.79	0.50	4.57	1.18	18.62	6.48	240.74

* Includes Puerto Rico

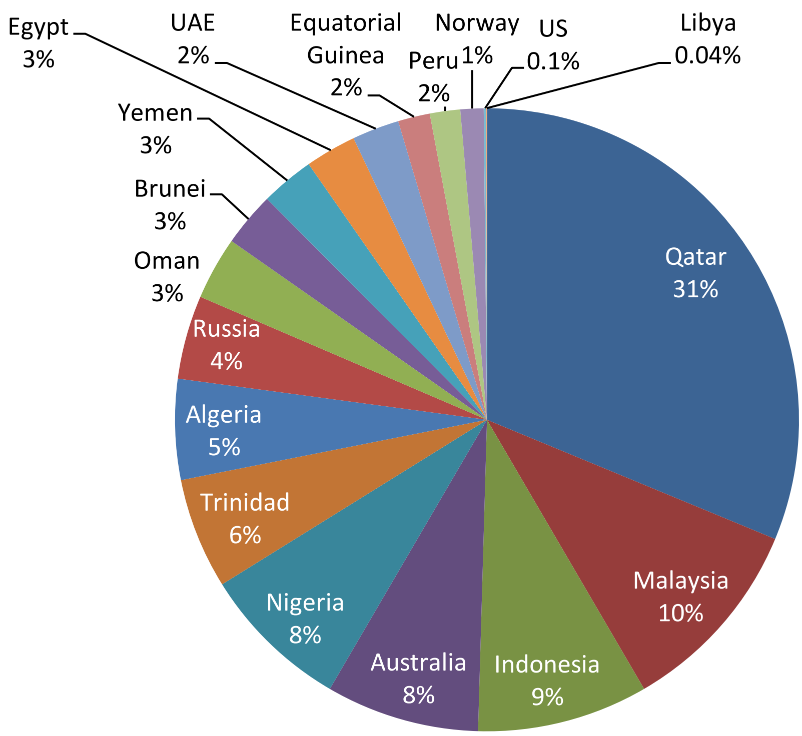


Figure 2.11 - % share of LNG exports by country, 2011

In the supply side of LNG, beside the remarkable increase in Qatar's LNG supply in the last decade (Drewry, 2010), it is important to notice the increasing number of exporters. Figure 2.12 shows how each country's % share of LNG global exports has developed as new players have entered the market; see Figure 2.1 for the total volume of traded LNG over the past decades.

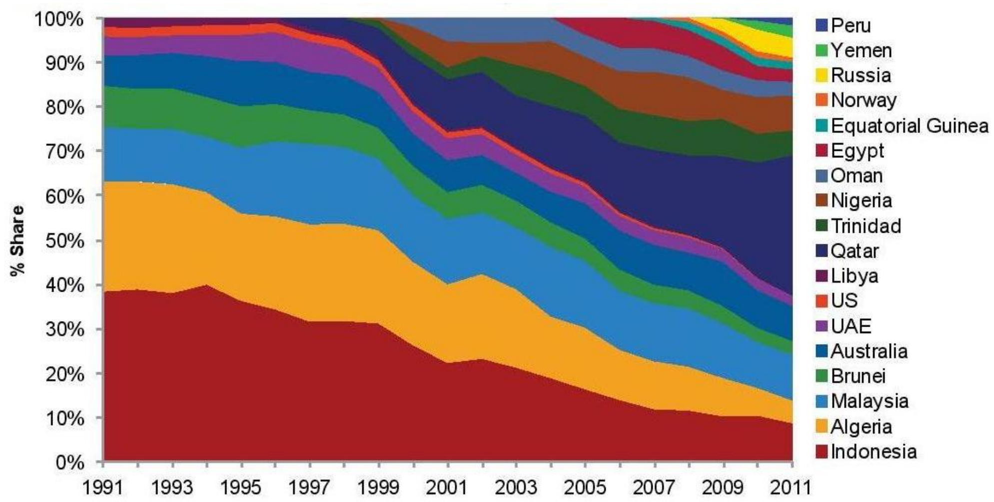
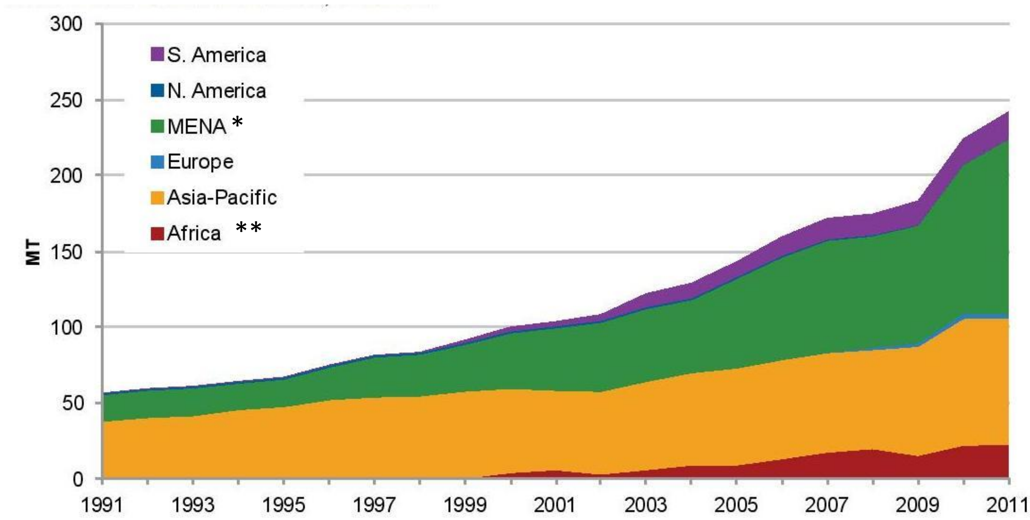


Figure 2.12 - % share of global LNG exports by country, 1991-2011 (source: IGU, 2012)

Regionally, Middle Eastern and North African exporters (currently Qatar, Algeria, Oman, Yemen, Egypt, UAE and Libya) left behind Asia-Pacific exporters (i.e. Malaysia, Indonesia, Australia and Brunei) in total volumes supplied in 2006 and have continued to put out more volumes to the market since then (Figure 2.13).



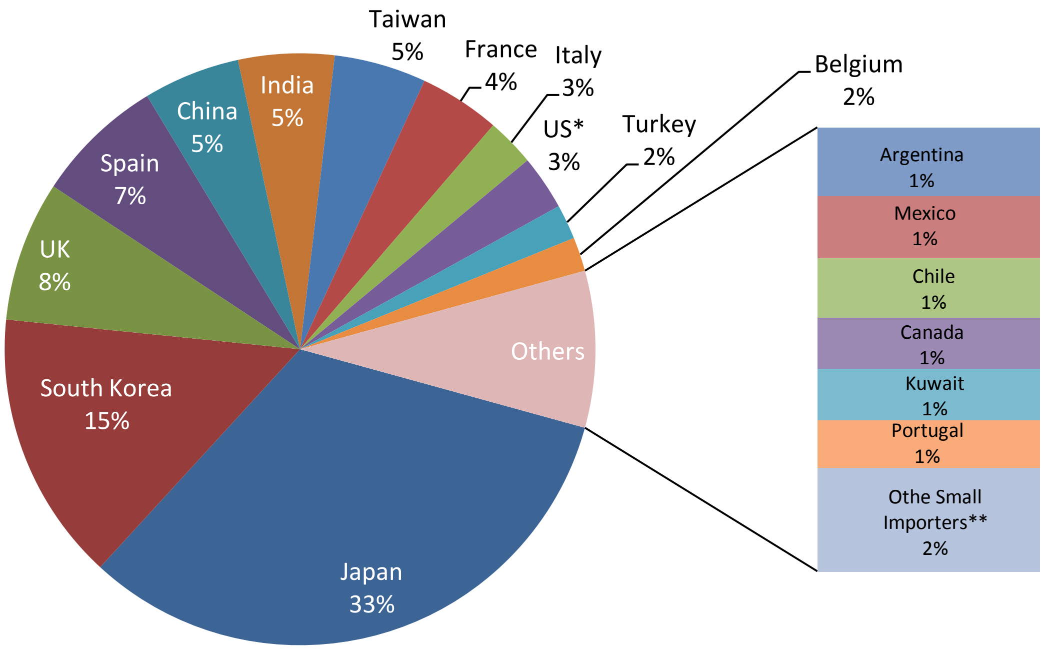
* MENA: Middle East and North Africa

** Africa refers to the African continent minus North Africa.

Figure 2.13 - LNG exports by region, 1991-2011 (source: IGU, 2012)

But this trend is going to change in the next decade and Asia-Pacific will take over as projection for growth in the Middle East and North Africa are limited, while in Asia-Pacific new Australian projects are coming online (Drewry, 2010). The Middle East and North Africa region faces several problems which make development in this region difficult; "these include rising domestic demand, regulatory or energy policy clarity, economic and political stability, sanctions (in the case of Iran), and reserves which are more difficult to recover" (IGU, 2012). The two regions named have been, are and will stay the most important LNG supply sources for the foreseeable future.

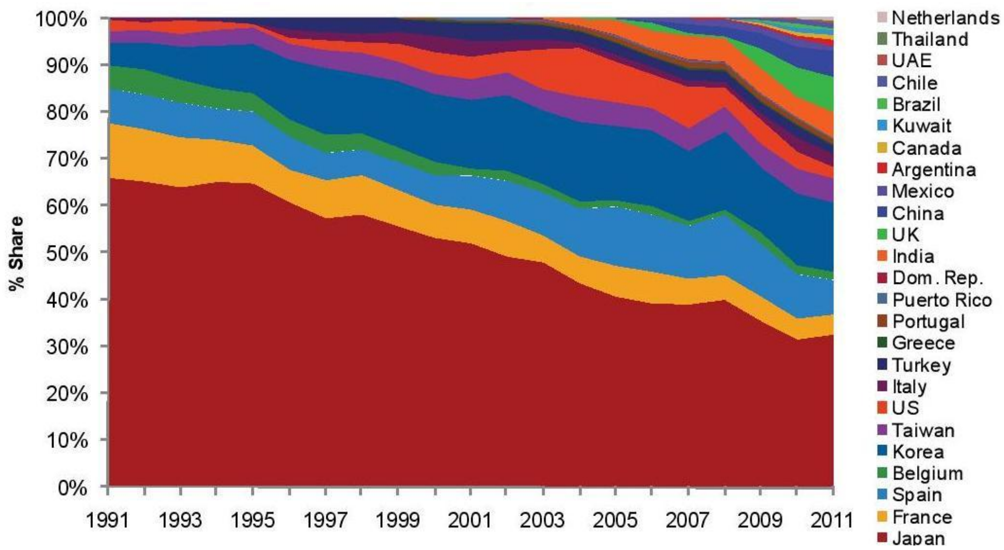
On the import side, Japan and South Korea are by far the biggest LNG importers in the world, such that in 2011 they imported about 115 MT (see Table 2.3) of LNG, which is about 48% of the world's LNG supply. Japan has been the backbone of LNG trade traditionally. "This country between 1977 and 2001 accounted for over half of global imports (reaching a peak of 74.5% in 1986)" (Drewry, 2010). Figure 2.14 shows the % share of LNG importers in 2011 out of total world LNG trade.



* Includes Puerto Rico
** Small importers include UAE, Greece, the Dominican Republic, Thailand, Brazil and the Netherlands. Each of these has imported less than 1% of world LNG supply.

Figure 2.14 - % share of LNG imports by country, 2011

Of the 25 countries importing LNG, 10 started their imports in the last five years, including, Argentina, Brazil, Canada, Chile, China, Kuwait, Mexico, the Netherlands, Thailand and UAE. It is interesting to see that three of these countries are located in South America and two in the Middle East, the regions which were not previously importers of LNG and were not expected to be LNG markets (IGU, 2012). Figure 2.15 shows how each country's % share of LNG global imports has developed since 1991.



* Korea refers to South Korea.

Figure 2.15 - % share of Global LNG imports by country, 1991-2011 (source: IGU, 2012)

In summation, given the numbers provided in Table 2.3, the trade flows of LNG by region can be derived as suggested in Table 2.4.

Table 2.4 - LNG trade volumes by region (MT), 2011

		Importers				
		North America	South America	Europe	Middle East	Asia
Exporters	North America	-	0.31	0.25	-	1
	South America	5.55	3.38	4.32	0.28	4.28
	Europe	0.37	0.15	2.25	0.06	1.07
	Africa (minus North Africa)	0.91	1.26	11.28	0.65	8.53
	Middle East and North Africa	6.77	1.6	48.83	1.99	55.42
	Asia-Pacific	0.19	-	-	0.31	82.13

Looking at the table three major trade flows of LNG are identified: from the Middle East and North Africa to Europe (about 49 MT), from the Middle East and North Africa to Asia (about 55 MT – Asia in this table does not contain the Middle East) and finally from Asia-Pacific to Asia (about 82 MT). These numbers imply that currently Europe (including the UK, Spain, France, Italy, Turkey, Belgium, Portugal, Greece and the Netherlands) and Asia (including Japan, South Korea, China, India, Taiwan and Thailand) are the main LNG consumer regions in the world. These two regions are to stay the main importers of LNG over the next decade, while Asia will lead with increasing imports in Japan, South Korea and Taiwan and the emergence of the mega-market of China and possibly India (Total, 2011). Figure 2.16 shows LNG imports in various regions from 2005 and a forecast to 2015.

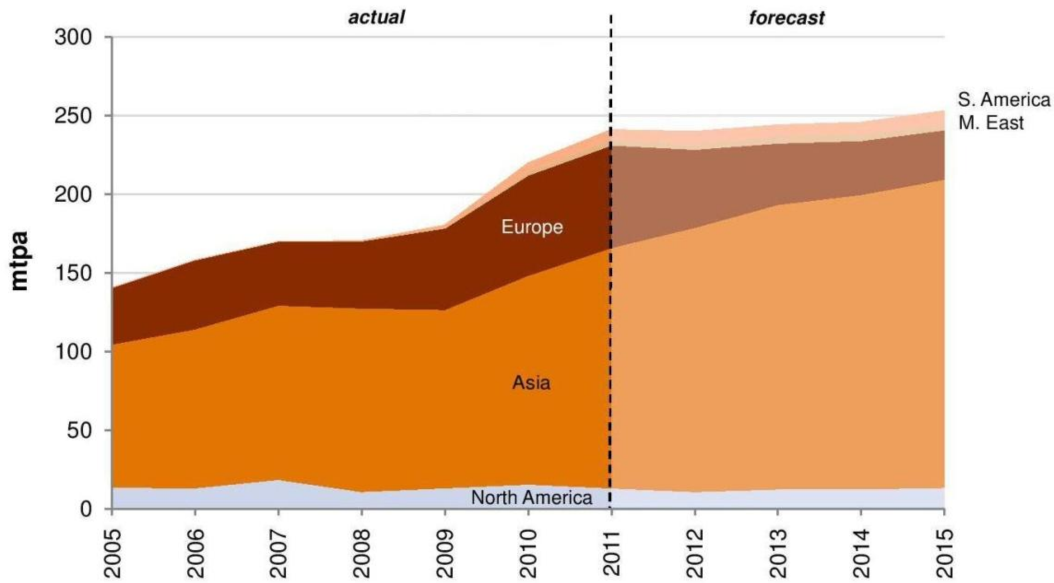


Figure 2.16 - LNG imports by region (MTPA), 2005-2015 (source: BG Group, 2013)

It was mentioned in 2.4.2 that North America, i.e. the US, used to be considered a major import region for LNG, such that between 2002 and 2007 imports to the US increased from about 5 MT to 17 MT and it was predicted that in 2010 the US would import 56 MT of LNG (roughly 20% of world supply in that year) which would have put it right behind Japan in terms of volumes imported by a country. But since then imports have considerably decreased and cargos are diverted to other markets (Drewry, 2010).

World LNG liquefaction and regasification capacity: in 2011, the world had 25 liquefaction plants including 95 Trains. Table 2.5 lists the number of plants, number of Trains and total liquefaction capacities with respect to different countries.

Table 2.5 - number of facilities, number of Trains and total liquefaction capacities with respect to different countries, 2011 (source: GIIGNL, 2012)

Country	Number of plants	Number of Trains	Capacity (MTPA)
Qatar	2	14	77
Indonesia	3	14	34.1
Malaysia	1	8	25
Nigeria	1	6	21.9
Australia	2	6	19.9
Algeria	3	18	18.4
Trinidad and Tobago	1	4	15.5
Egypt	2	3	12.2
Oman	1	3	10.8
Russia	1	2	9.6
Brunei	1	5	7.2
Yemen	1	2	6.7
UAE	1	3	5.8
Norway	1	1	4.5
Peru	1	1	4.5
Equatorial Guinea	1	1	3.7
US	1	1	1.3
Libya	1	3	0.7
Total	25	95	278.8*

* Due to planned maintenance or unexpected problems the plants may not produce 100% of their capacity.

Regionally speaking, in 2011, the Middle East and North Africa has 131.6 MT of the world liquefaction capacity (47% of world capacity), the Pacific Basin has 97.1 MT (34% of world capacity) and the Atlantic Basin has 50.1 MT (17% of world capacity). In the short-term until 2016 the liquefaction capacity of the Pacific Basin, essentially Australia, is expected to increase considerably to about 150 MT, which would result in the share of this Basin in total world capacity (335 MT) becoming about 44%, and hence the biggest LNG supply region (IGU, 2012). Figure 2.17 represents the world’s liquefaction capacity development since 1991 and forecasts it to 2016. The major worldwide supply added in 2016 is to come from Australia.

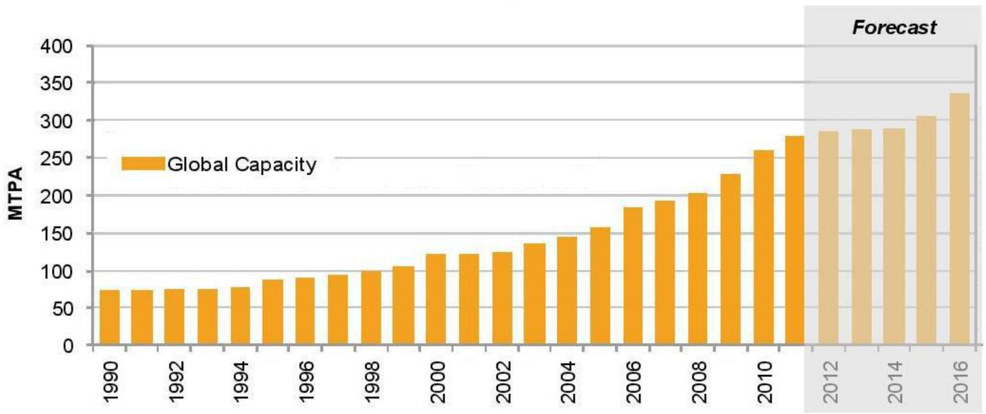


Figure 2.17 - LNG liquefaction capacity growth in the world (MTPA), 1990-2016 (forecast is based on the projects under construction) (source: IGU, 2012)

In 2011, 89 LNG regas terminals were in operation, representing 608 MTPA in regas capacity. Japan is the biggest capacity holder with 29% of world capacity (with 28 regas terminals); the remainder from larger to smaller includes: the US 20% (12 terminals), South Korea 13% (four terminals), Spain 7% (six terminals), the UK 6% (four terminals), China 3% (six terminals), France 3% (three terminals), India, Taiwan and Mexico 2% each (each with two terminals), the Netherlands, Turkey, Italy, Canada, Argentina, Belgium, Brazil Thailand, Chile, Greece, Portugal and Kuwait with about 1% each (with one, two, two, one, two, one, two, one, two, one, one and one terminal(s)), and finally UAE, Puerto Rico and the Dominican Republic with less than 1% each (with one terminal) (GIIGNL, 2012). For a brief list of LTC contracts and the respective liquefaction plants and regas terminals, see GIIGNL (2012); Drewry (2010) provides a short discussion on project developments (regas terminals and liquefaction plants) for each country until 2020.

Looking at the numbers Japan, the US and South Korea held 62% of global regas capacity in 2011. Including the UK and Spain, the top five regas capacity markets held 75% of global capacity in 2011 and the remaining 25% was located in the 20 other LNG importing countries.

Regas capacity continues to develop especially in new markets. Out of 24 projects being constructed (including new terminals and terminal expansions), 18 are completely new. On completion of these new terminals, five new countries will have the possibility to import LNG: Indonesia, Israel, Malaysia, Poland and Singapore. These will join the new countries that have only brought terminals on stream in the last five years (as mentioned previously) (IGU, 2012), Figure 2.18 shows the growth of regas capacity in the world since 2000 and forecasts it to 2016.

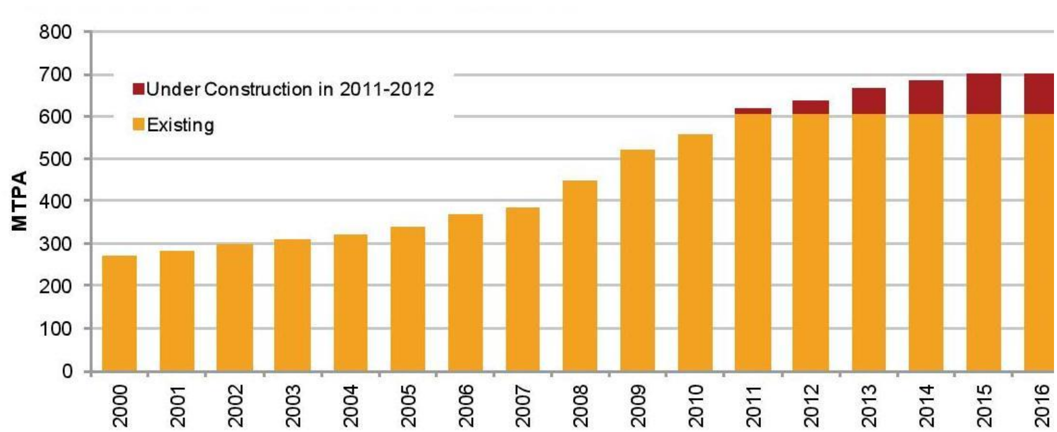


Figure 2.18 - world LNG regs capacity (MTPA), 2000-2016 (source: IGU, 2012)

Given the numbers there is a mismatch between world liquefaction and regas capacity. This is to a degree intentional due to concerns with regards to security of supply or seasonal-load balancing considerations by the LNG importers (IEA, 2011). A country like Japan was able to cope with the Fukushima crisis due to its considerable regas capacity and the resulting possibility of extra LNG imports (IGU, 2012).

Regionally speaking, according to the numbers presented, East Asia including Japan, South Korea and Taiwan as well as growing China, had the majority (47% or 286 MTPA) of world regas capacity in 2011. East Asia has traditionally had a bigger share of world capacity, (according to Drewry (2010) about 70% through the 1990s and early 2000s, excluding China as it is not an importer in this period yet), but over time, due to the increase in regas capacity in other regions and mainly in the US, its share has decreased.

It is interesting to note that the utilization rate of regas terminals in Asia, Europe and the US in 2011 has been 45%, 46% and less than 5%, respectively (GIIGNL, 2012). Due to heavy under-utilization in the US (owing to the rise of shale gas and the resulting self-sufficiency), a number of regas terminals in the US have announced plans to convert their facility into liquefaction plants and start exporting gas from the US as LNG (Henderson, 2012). Figure 2.19 is the % share of different regions for regas capacity over time.

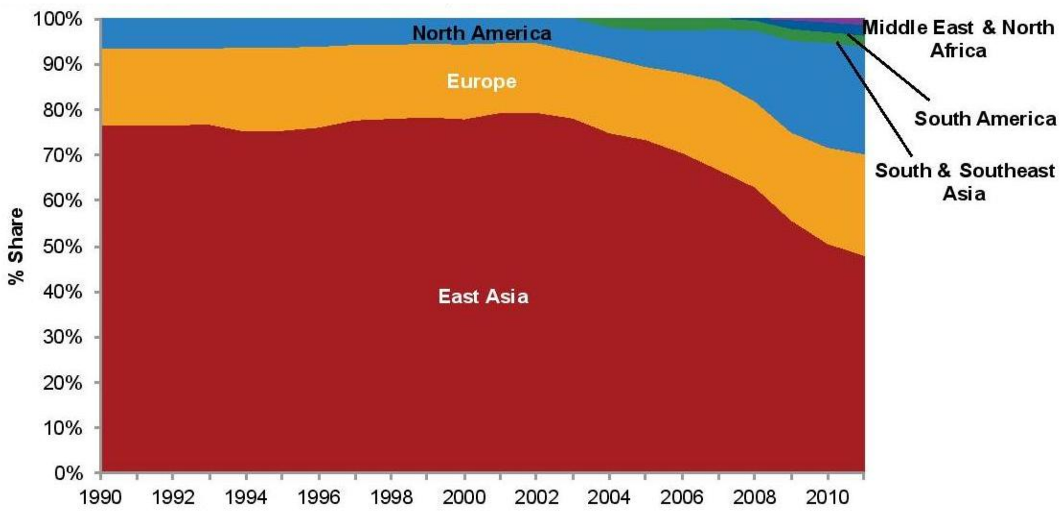


Figure 2.19 - Regas capacity by region, % share of total (source: IGU, 2012)

LNG carriers: the world LNG fleet consisted of 359 vessels at the end of 2011, with a total shipping capacity of 51.9 million cubic-meters (with the average capacity of roughly 145 000 cubic-meters per vessel) (GIIGNL, 2012). Looking at the fleet in terms of containment system it is seen that most LNG tankers are of a membrane type (Figure 2.20).

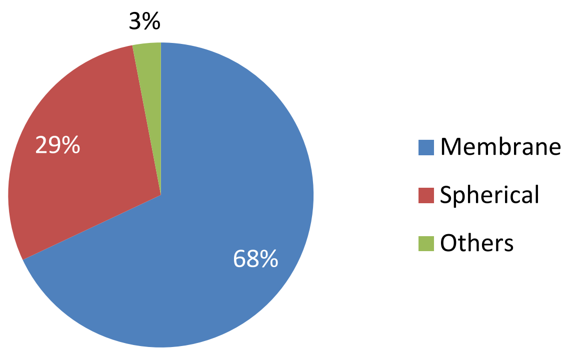


Figure 2.20 - Global LNG fleet by containment system, 2011 (number of carriers, % of total) (source: GIIGNL, 2012)

It is interesting to note that the smallest cross-border LNG tankers, usually between 14 000 to 40 000 cubic-meters, are mainly used in transporting LNG from Southeast Asia to small regas terminals in Japan. The most common class of LNG tanker has a capacity of between 125 000 to 149 000 cubic-meters. Over the past decade the majority of LNG tankers delivered are in the class of 150 000 to 177 000 cubic-meters. Finally, the largest category of LNG vessels is the Q-Series used by Qatar in serving its huge projects, and it consists of Q-Flex (210 000 to 217 000 cubic-meters) and Q-Max (261 700 to 266 000 cubic-meters) tankers (IGU, 2012). Figure 2.21 presents the distribution of capacity for LNG tankers.

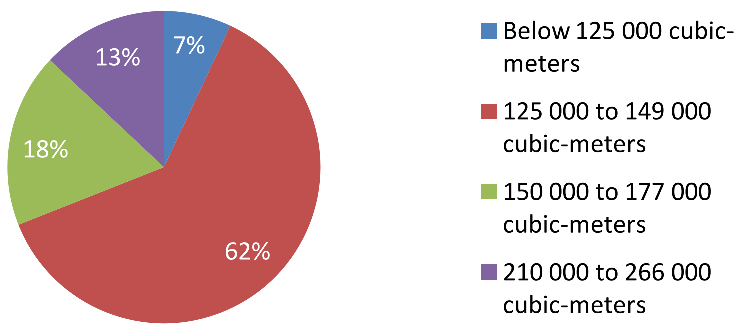


Figure 2.21 - Global LNG fleet by capacity, 2011 (number of carriers, % of total) (source: IGU ,2012)

The average age of the global LNG fleet in 2011 was about 11 years (Figure 2.22 is the age range of the tankers), mainly because of the deliveries from the last new build order boom (there have been three booms until the end of 2011) (IGU, 2012).

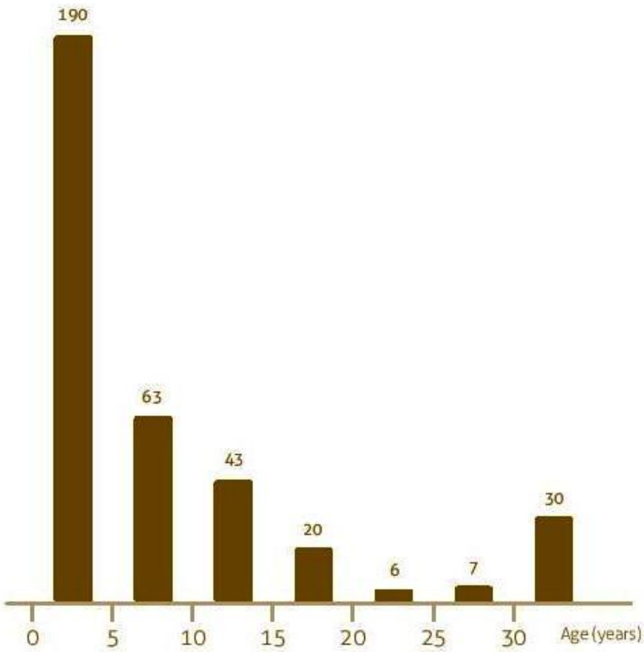


Figure 2.22 - Global LNG fleet by age, 2011 (number of vessels in each age range) (source: GIIGNL, 2012)

The first building boom occurred between the late 1970s and early 1980s when large LNG exporters Malaysia and Indonesia started exporting LNG. The second one occurred between 1989 and 2000 when exporters such as Qatar and Australia started supplying LNG, while countries such as Indonesia and Malaysia ordered their second generation of tankers. The last of the three booms occurred between late 2002 and 2009 (Drewry, 2010). It should be said that it took 33 years for the LNG fleet to reach 100 vessels (the first vessel was delivered in 1965) but it only took nine years for the fleet to reach 200 vessels (May 2006). The fleet then, in less than three years (February 2009) reached the 300 threshold (Drewry, 2010). Table 2.6 suggests the fleet size and age profile in April 2010, looking at which the three booms are seen.

Table 2.6 - LNG fleet size and age profile (April 2010) (source: Drewry, 2010)

Year of build	Size Category ('000 cubic-meters)							
	18-50	50-75	75-125	125-150	150-200	200-250	250+	Total
<1970	1	2	0	0	0	0	0	3
1970-74	3	0	5	0	0	0	0	8
1975-79	2	0	5	21	0	0	0	28
1980-84	0	0	0	17	0	0	0	17
1985-89	0	0	0	4	0	0	0	4
1990-94	1	0	2	15	0	0	0	18
1995-99	3	2	0	25	0	0	0	30
2000-04	1	0	0	56	0	0	0	57
2005+	1	1	2	86	42	30	12	174
Total	12	5	14	224	42	30	12	339

Operating economy and safety measures state that vessels' owners consider retiring their tankers when they reach 30 years of age, although there are much older tankers (more than 40 years of age) too. The tightening of the charter market and prediction of a rise in charter rates, as a consequence of an event like the Fukushima crisis, can convince owners to postpone the retirement of their vessels (IGU, 2012). The order book at the end of 2011 consisted of 67 vessels of which 57 orders were put in 2011, this high number of orders in 2011 might be the start of a new building boom. Figure 2.23 illustrates the status of the worldwide LNG fleet and order book of 2011.

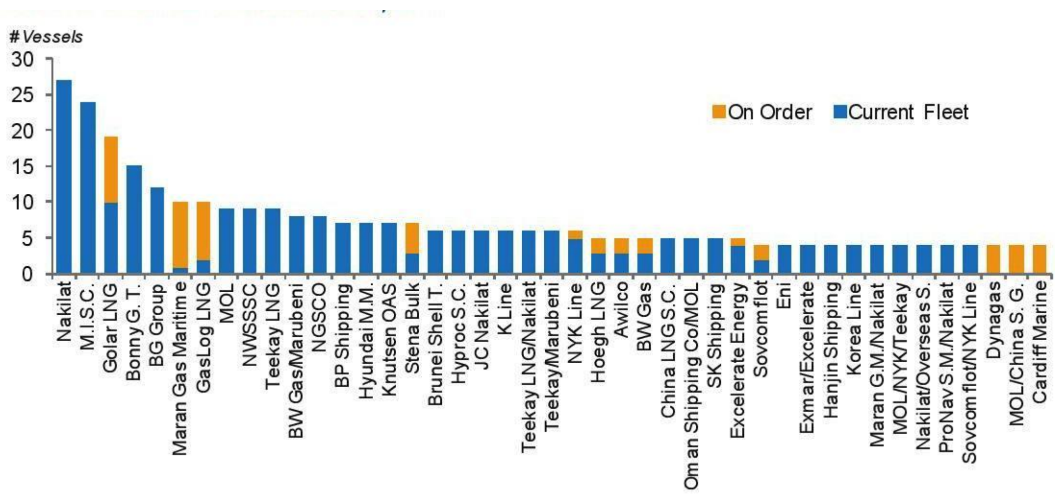


Figure 2.23 - LNG fleet and order book, 2011 (source: IGU, 2012)

In terms of constructing LNG tankers, shipbuilding used to be dominated by the European and American yards. But since the mid-1980s and early 1990s these builders lost their position firstly to Japanese and more recently South Korean builders. Of the current fleet, South Korea has built more than 50% of the vessels. Currently LNG tanker construction worldwide is dominated by three South Korean builders: Daewoo, Hyundai and Samsung. They are followed by three Japanese builders: Mitsubishi, Kawasaki and Mitsui. Japanese builders recently have been receiving orders mainly from the companies that are interested in early delivery slots (Drewry, 2010).

The traditional and largest players in owning and ordering the vessels have been NOC-affiliated shipping companies such as Nakilat (from Qatar) and MISC (from Malaysia), in addition to Japanese shipping companies such as Mitsui O.S.K. Lines (MOL) and Teekay. It should be said that recently independent shipping companies such as Golar LNG have been quite active in ordering vessels too and have joined the club of big vessel owners (IGU, 2012). Traditionally, LNG tankers have been ordered by owners where they have had long-term charters with LNG projects (for LNG tanker contracts, see Section 4.3). But since 2000, there have been some orders for tankers on a speculative basis. Vessel-owners have responded to the rapid expansion of the LNG sector (see Figure 2.1) by placing orders without having long-term charters for their use and have been relatively successful in securing employment for their tankers, sometimes on a long-term basis but also in the spot market (Flower, 2012). It is interesting to note that under some traditional LTCs, tankers are exclusively dedicated to the contract, which means that if a contract (LTC) is stopped for whatever reason, the tankers have to lie up (this is considered as a kind of contract rigidity) which in new LTCs is eased and solved.

It is predicted that the demand for LNG vessels in the future will come from mainly two countries: Australia and China. Australia, given its substantial liquefaction capacity development and China, because of its predicted sizeable growth for LNG demand (Drewry, 2010).

2.5. Concluding remarks

This chapter provides an overview of the current status of the worldwide LNG market and establishes the composition of its supply chain. The LNG business is studied showing that the majority of LNG has been sold on LTCs though the form of LTCs is changing and converting to self-contracts from traditional ones in liberalizing and in particular liberalized markets. It is established that according to LTCs, the bulk of the product is delivered by the fleet controlled by the producers (self-contracts or traditional LTCs with CIF/DES deliveries) but alternatively, the product can be off-taken by the buyers' tankers in the liquefaction plant (traditional LTCs with FOB deliveries). In addition to these, it is established that apart from LNG sales based on LTCs, the spot sale in arbitrage (particularly for self-contracts) and spot sale for uncommitted product occurs in the LNG business and is carried out by the fleet of the LNG producer. Next a short discussion on LNG pricing is presented and finally some numbers and statistics for the LNG industry are provided.

Given the understanding of the LNG industry achieved in this chapter, the format of the business and the fact that the LNG producer usually manages both production and distribution of product is clear. This knowledge assures us of the validity of the research problem of the thesis and provides the foundation for model development in the following chapters. But before model formulation, the framework for modelling should be established. In the next chapter the literature on the IRP as the framework is reviewed.

Chapter 3

Review of Marine IRPs

3.1. Introduction

In dealing with the simultaneous production and distribution of LNG, the IRP, as discussed in Chapter 1, can provide the mathematical background for model development. A review of the literature on this problem and a perspective on its research context is the main focus of this chapter (3.2).

The IRP is concerned with vehicle/vessel routing and scheduling in determining the time and size of deliveries with regard to the inventory constraints over a given planning scope (Federgruen and Simchi-Levi, 1995). This problem is in fact a combination of two old problems in operations research; the VRP (see the glossary and abbreviations at the beginning of the thesis) and the inventory management problem. The VRP concerns serving a set of customers using a fleet of vehicles, considering cost minimization, revenue maximization or both. In solving VRPs, customers' demand and the cost of vehicle trips between the depot and a destination are the main factors taken into account (Brandão de Oliveira, 2010). For a comprehensive review of VRPs see Toth and Vigo (2002). The second part of an IRP, inventory management, is the act of maintaining sufficient stocks of products/goods given the inventory costs and constraints – allowing for the flow of the product into and out of the inventory – that will guarantee a relatively smooth operation for a production system or a business activity (Taha, 1992). For a survey of inventory management problems, see Silver et al. (1998).

Looking at the IRP context from an applied research point of view, two main categories of works can be identified; road IRPs (Barnes-Schuster and Bassok, 1997, Aghezzaf et al., 2006) and maritime IRPs (Ronen, 2002, Christiansen et al., 2011). This thesis is focused on a maritime problem, hence the literature review concentrates on marine IRPs. A comprehensive survey of IRPs is available from Andersson et al. (2010).

3.2. Marine IRPs

Looking at maritime problems as an IRP was rare up until the last decade and before this time IRP research was focused mainly on road problems. It should be mentioned that maritime IRP research to date has been centred on solid and liquid bulk businesses (Christiansen and Fagerholt, 2009). There are significant differences between marine and road IRPs which divides them into two different distinct categories; for a discussion on this issue, see Ronen (2002). The main differences are:

- Whereas a truck fleet in a road IRP is often made up of identical trucks, the ships in a maritime IRP are different from each other with regard to their size, cost and other characteristics. Hence, while in road problems almost always every vehicle can be assigned to every cargo, in a maritime context the vessel is chosen with respect to quantities such as the cost and size of the cargo.

- Spot chartering-in or spot chartering-out of vessels in a maritime context is often possible and does take place, however does not occur in road problems. This implies that the fleet size and mix in maritime IRPs might change in a short period of time.

- Due to considerable investment, the production rate of the product(s) being traded is not a decision factor in maritime IRPs, hence there are no production stoppages or reductions. While in road cases the production rate can be a decision factor.

The category of Maritime IRPs is very diverse; the large variety of aspects and assumptions considered in problem formulation and modelling make the group difficult to classify (Dauzère-Pérès et al., 2007). Studying this category as a whole can be carried out from two perspectives: solution methods/heuristics and problem characteristics (Andersson et al., 2010b). In this thesis a commercial solver named IBM ILOG CPLEX Optimization Studio 12.3 is used for solving the model presented in Chapter 4. Thus, in reviewing the literature on IRPs the solution methods, although briefly covered, are not the main focus of the work, whereas the problem structure and research results are.

A primary maritime IRP is considered by Miller (1987). In his problem a set of consumer ports are supplied from a central producer port with several products (gasoline antiknock compounds). The aim is to minimize transport costs in the planning horizon while not permitting any shortfall at the inventory of the destination ports given their varying consumption rate over time (demand in all maritime IRPs is deterministic). The ships visit several consumption ports on a trip and deliver their load that is made of a few products. Miller (1987) solves the problem using an iterative heuristic. He firstly generates a primary feasible schedule for the ships for the problem scope given the inventory constraints, this includes several trips for each ship; the schedule for each trip comprises the set and sequence of consumers ports visited, the set of products and quantity of each on board a ship in leaving the producer port, the amount of products delivered to each consumer, and arrival/departure time to/from a consumer port. In next step, Miller (1987) improves that schedule iteratively by making small changes to it while ensuring the inventories are satisfied. A change is positive if it results in a smaller transport cost for the problem.

Shih (1997) deals with a case of maritime IRP. In his problem there are a set of production ports that supply a Taiwanese importing terminal with different types of coal. Each production port supplies several types of coal. The importing terminal, after receiving the cargos in its inventory, dispatches the coals to power plants inland. Each of the plants consumes a pre-determined mix of coals for each time unit and hence, has an explicit demand. The problem focuses on hiring a minimum number of spot ships with a direct delivery scheme for transferring the coals from the ports to the importing terminal, plus inventory management at the terminal and minimization of the relative costs over the problem timeframe. In this IRP uniquely, and in contrast to any other maritime IRP, the decision-maker is the consumer (importing terminal) and not the producer. The model developed is solved using CPLEX. The formulated problem proves to be more efficient in terms of planning and cost saving than common industrial practices. Liu and Sherali (2000) solve the same problem, with a larger number of suppliers and importing terminals. Furthermore, they define the model in a way that the mix of coals that each power plant needs is decided given the environmental factors such as the sulphur oxide and ash percentage of the coal supplies.

Christiansen and Nygreen (1998a, 1998b) address an IRP in the maritime context. Here there is no central stock rather a set of ports that some of them are the producers and the rest are consumers of ammonia. The goal, in this problem, is the minimization of transport costs so as not to allow any shortfall or excess in the product stock levels at any of the harbours given the time varying production and consumption rates. Partial delivery is permitted. Christiansen (1999) discusses that to solve real world cases, the problem should be decomposed into a ship routing problem and an inventory management one. She generates feasible ship schedules and harbour visiting sequences then matches them in the required timeframe.

Ronen (2002) presents a model for simultaneous inventory management and ship routing/scheduling for oil products and chemicals. He formulates a network of production and consumption ports with limited inventories where the deliveries are direct and are carried out by a fixed fleet of ships with spot chartering of extra vessels being permitted. The demands are time varying. The system cost in this problem includes the shortage costs for consumption ports and fleet management (distribution) expenses. Ronen (2002) solves the problem using a heuristic algorithm. The heuristic tries to follow the logic of a human planner over the planning scope; whenever there is a shortage of products a multi-product cargo from the nearest possible port is planned; the same process happens for the overflow of products in a plant, here a multi-product ship is dispatched to the nearest destination that can accept it.

Dauzère-Pérès et al. (2007) address a maritime industrial IRP where a set of products (different types of calcium carbonate slurries) from a manufacturer are distributed among several tank-farms given their time varying demands. The distribution (direct delivery) is carried out using a fleet of tankers. Interestingly the vessels in this problem can be chartered-out if they are not being used. The goal in the problem is cost minimization in both inventory management of the tank-farms and transport. A formulation is developed for the problem but standard solvers cannot solve it for real world cases, hence a heuristic is developed. The core of the heuristic is finding a primary solution for serving a fixed order of tank-farms (where the order in which the tank-farms are served defines their importance), then swapping the place of the tank-farms in the order (which changes the distribution strategy) and checking whether the swap results in a smaller system cost. A rolling horizon process connects the consecutive periods and covers the whole study scope. The solution suggested decreased the annual cost for the manufacturer by about 5% (seven million dollars).

Al-Khayyal and Hwang (2007) formulate a model for a network of production and consumption ports with multiple liquid products, where supply and demand rates are constant. The problem is formulated as a mixed integer nonlinear programme for transport cost minimization (with partial deliveries) over the planning scope, but later it is converted to a linear equivalent programme. An illustrative example (three ports in a planning horizon of two days) is solved using a commercial software (CPLEX 7.5), however for solving real scale problems, Al-Khayyal and Hwang (2007) state that a heuristic needs to be developed.

Rakke et al. (2011) minimize the transport and penalty costs in fulfilling the LTCs and maximize the revenue in uncommitted product spot sales (all direct deliveries) in generating an ADP for an LNG project. In their work, each LNG buyer with an LTC has a specific predicted demand for each month that needs to be fulfilled. The set of decisions relating to the deliveries to the buyers, given the tank-farm constraints in the production port, during one year, shapes the ADP. Spot chartering of tankers at high prices is permitted. Rakke et al. (2011) permit under delivery for the LTCs albeit with a penalty. The problem is solved using a rolling horizon process.

Shen et al. (2011) address a case of IRP for distribution of crude oil. Here there is a centre which supplies several customers with variable demands over time. There are three modes of service; the marine route, the marine route through canals and the marine route via pipeline (where for part of the route oil is transported by pipeline). There is a fleet of fixed tankers serving the project but extra tankers can be spot chartered (deliveries are direct). The goal of the model formulation is to minimize transport and customer inventory costs over the whole study scope, where backlogging is permitted. Shen et al. (2011) solve the problem with a rolling horizon process where each period is solved using a Lagrangian relaxation method.

A network of production and consumption ports is modelled by Christiansen et al. (2011). In this maritime IRP several types of non-mixable cements and raw materials are distributed given time varying consumption and production rates. Each ship, having several compartments, can carry different types of cement and material together. Partial delivery is permitted. The objective of the problem is to minimize transport and inventory costs over the problem scope. Christiansen et al. (2011) solve the problem on a rolling horizon process where each period is solved by a heuristic. In the heuristic first, a primary short route (a few visits) is assigned to a ship. As a result, there are capacity breaches in some ports, then, in an iterative process the plan is improved. In each iteration, the port with the most critical breach is chosen and an extra shipment of the product for which there is a shortage is added to the system. There might be more than one option for choosing a shipment (different ships, compartments, or ports, and, also different options of where to place the delivery in the ship's delivery sequence); here the heuristic chooses the one which minimizes the system cost in the period being considered. This is an industrial case, the company which is running the system has confirmed that the solution method suggested provides better solutions in comparison to the usual manual planning method.

A maritime IRP for a single bulk product is formulated and solved by Song and Furman (2013). Here, there is a network of consumer and producer ports which is served by a fleet of spot tankers. The demands are time varying, and partial delivery by ships is permitted. The objective is to minimize transport costs in the planning scope. To solve the problem, the feasible solution space of the problem is divided into several sub-spaces, then in each of these the problem is solved by a branch-and-cut algorithm; finally, the solutions found for the sub-spaces are compared and the best one is chosen. The procedure suggested is capable of solving a real instance with eight ports, five vessels and two months of planning time.

An LNG ship routing and scheduling problem with regard to the berth and inventory constraints in the supply side (IRP) is addressed by Halvorsen-Weare and Fagerholt (2013). In their work they aim to establish an ADP for an LNG production plant according to its LTCs where there are specified time windows by the LTC holders for fulfilling their predicted demands over the course of the year. In this work, in contrast to Rakke et al. (2011), under delivery is not permitted. Hence, Halvorsen-Weare and Fagerholt's (2013) method of designing the ADP is stircketer than that of Rakke et al. (2011).The goal is minimization of delivery costs of LTC shipments over a year. Halvorsen-Weare and Fagerholt (2013) assume that the uncomitted product/LNG is sold OTC but only spot chartered tankers serve this type of sale. All delievries are direct. Using the model developed, several numerical instances are solved. The examples are solved using three different methods: (a) solving the full model using the Xpress-Optimization Suite (a commercial solver), (b) decomposing the model into a routing problem (deciding which vessels are to serve which cargos and in what sequence) and a scheduling one (to use the routing decisions in finding a schedule that is feasible given the berth capacity and inventory constraints). In this solution both of the problems generated are solved by the Xpress-Optimization Suite. And finally, (c) decomposing the model and using a heuristic (a local search algorithm) for solving the routing problem, then solving the scheduling problem using the Xpress-Optimization Suite. Solution methods (b) and (c) are successful in solving real world cases.

To provide a better understanding of maritime IRPs, the papers considered are classified (Table 3.1) according to several interesting problem characteristics. This classification, which is used in Chapter 4, will inform the model development. The features are:

- Topology: in maritime problems there can be one central production/consumption port and several consumption/production ports (one-to-many). Alternatively, there could be a network of production and consumption ports (many-to-many).

- Routing: a ship in a maritime IRP is often loaded in a production port and delivers all of its cargo directly to a consumption port (direct). However there are problems where partial delivery is permitted and unloading /and loading of a ship occurs on multiple stops (multiple).

- Inventory focus: the focus of inventory management in maritime IRPs is either at both production and consumption ports together (both-sides), or merely one of them, i.e. just at the production or the consumption port(s) (one-side). When the focus of inventory is just on the consumption side, a common assumption is that the product is available at the supply side at will, which is often due to considerable inventories and production rates in production ports in the relative IRPs. Instead, when focusing on the production side, it is assumed that inventories at the consumption side have enough capacity whenever a vessel arrives. This is only observed for LNG problems and is discussed further in the next chapter.

- Inventory management: in managing the inventories being considered in the maritime IRPs, defined above, shortage of a product is treated in three different ways. In some problems shortage is not permitted (fixed); in a group of IRPs it is permitted with a penalty (stock-out), and finally in a set of IRPs, shortage is permitted, given a penalty, but it is considered as postponed demand and satisfied later (back-order).

- Product: in many maritime IRPs a number of products can be delivered by a vessel (several), but cases also exist where a single product is delivered (one).

3.3. Concluding remarks

This chapter presents a survey and subsequent classification of maritime IRPs with respect to common problem characteristics.

Of the maritime IRPs studied, Halvorsen-Weare and Fagerholt (2013) and Rakke et al. (2011) focus on the LNG sector. Both of the aforementioned works, like this research, deal with the routing/scheduling of LNG tankers sourced from a production port given the inventory constraints. But this problem in these papers is addressed over the horizon of one year, and they create an ADP. However, this research addresses the problem at an operational level and deals with operational issues that may arise during the day-to-day running of a project. ADP design and operational planning are two different levels of planning in an LNG project and are concerned with different issues (this is discussed more in the next chapter); hence this work does not improve upon Halvorsen-Weare and Fagerholt (2013) and Rakke et al. (2011) but is rather an original piece of research.

Having reviewed the research literature for previous work on the maritime IRP problem, and built upon the LNG business discussion provided in Chapter 2, we can now proceed with the formulation of a mathematical model for simultaneous LNG production and distribution at the operational level. The formulation, a MIP model, is presented in the next chapter.

Table 3.1 - Characteristics of maritime IRPs

Research	Characteristics				
	Topology	Routing	Inventory focus	Inventory management	Product
Miller (1987)	One-to-many	Multiple	One-side (consumption)	Fixed	Several
Shish (1997)	One-to-many	Direct	One-side (consumption)	Fixed	Several
Christiansen and Nygreen (1998a, 1998b)	Many-to-many	Multiple	Both-sides	Fixed	One
Ronen (2002)	Many-to-many	Direct	Both-sides	Stock-out	Several
Dauzère-Pérès et al. (2007)	One-to-many	Direct	One-side (consumption)	Fixed	Several
Al-Khayyal and Hwang (2007)	Many-to-many	Multiple	Both-sides	Fixed	Several
Rakke et al. (2011)	One-to-many	Direct	One-side (production)	Fixed	One
Shen et al. (2011)	One-to-many	Direct	One-side (consumption)	Back-order	One
Christiansen et al. (2011)	Many-to-many	Multiple	Both-sides	Fixed	Several
Song and Furman (2013)	Many-to-many	Multiple	Both-sides	Fixed	One
Halvorsen-Weare and Fagerholt (2013)	One-to-many	Direct	One-side (production)	Fixed	One

Chapter 4

An Operational Model

4.1. Introduction

It was established in previous chapters that liquefaction/production and shipping/distribution in the LNG industry are usually managed by one decision-maker, the LNG producer, and can therefore be modelled as a single IRP. This would combine the VRP and inventory management problem, aiming to maximize the profit at an operational level of planning (this is the level of model developed in this research; as previously mentioned in Section 1.3, objective 2). In Chapter 2, it was established that LNG producers sell LNG on traditional LTCs with CIF/DES and FOB deliveries (see 2.4.1) and on self-contracts with CIF/DES deliveries (see 2.4.2). For the producers there are also opportunities of spot sales in arbitrage and for uncommitted product (both being carried out by the producer's fleet; see 2.4.3).

Before model development, perhaps some discussion would be informative and helpful in clarifying the meaning of operational decision-making in LNG production and distribution given the established selling methods, and crafting a clearer link between the modelling technique, IRP, and the LNG business phases modelled: liquefaction and shipping.

Combined planning of production and distribution in LNG projects by the producer is generally carried out on three different levels:

- **Strategic (long-term) planning** includes a financial analysis process and is concerned with the evaluation and justification of overall project. It is here that factors such as the size of the liquefaction plant, magnitude of the fixed tanker fleet and portfolio of the LTCs are determined.

- **Tactical (mid-term) planning** results in the ADP (see the glossary and abbreviations at the beginning of the thesis) that is ultimately presented to LTC buyers (buyers with traditional LTCs and self-contracts) by the producer. Here both FOB and CIF/DES deliveries to the LTC buyers for a year are decided and determined by the producer.

- **Operational (short-term) planning** addresses the day-to-day operational aspects of the liquefaction and shipping processes by the LNG producer (Rakke et al., 2011).

There are two main concerns that necessitate the presence of an operational planning stage – and hence the model developed in this research – in an LNG project. Firstly, the ADP which is designed in a higher level of planning and is supposed to be implemented in operation, is not usually executed accurately and it is modified in the light of operational requirements during the project, and changes in the predicted demand of the LTC buyers over the course of the year for which the ADP was planned (Flower, 2011). Operational requirements in an LNG project are issues such as bad weather or technical problems with the tankers and/or liquefaction plants. The demand of the LTC buyers may change and be different from what was foreseen in the ADP and, hence, the buyer may want to amend the time and amount of his deliveries mentioned in the ADP[1]. These operational requirements and changes in demand are taken into account and responded to in operational planning.

The second key reason for operational planning is that the spot sales for uncommitted product or in arbitrage, which affect the LNG production and distribution by the LNG producer, need to be decided in practice and in response to the opportunities that arise

[1] A delivery, the amount of LNG an LTC buyer receives on a day, depending on its size might be off-taken/carried by several tankers and consist of several LNG cargos, or may be one tanker, i.e. one LNG cargo. Most deliveries in the LNG industry consist of only one cargo (Flower, 2011).

in the market. For a spot sale to be carried out there should be a demand; this demand is unpredictable, for example, a cold winter creates an unforeseen extra requirement for gas/LNG and, as such, a high price for it, and this should be assessed in practice. Given this unpredictability, planning uncommitted product sales and arbitrage[1] in strategic or tactical planning is not reasonable. In Rakke et al. (2011) and Halvorsen-Weare and Fagerholt (2013), which both address an LNG production and distribution project at a tactical level, uncommitted product sales are taken into account (arbitrage is not considered in any of those works and it is a novelty of this research). Halvorsen-Weare and Fagerholt (2013) acknowledge that uncommitted product sales should be planned in practice and correctly argue that these sales are just considered as a means of controlling the inventory level in designing the ADP; without these sales the LNG production plant will run out of inventory. Halvorsen-Weare and Fagerholt (2013) do not take into account the profit of uncommitted product sales in their problem, as the goal is not profit maximization for those sales, but is rather the fulfilment of LTC obligations and producing the ADP. Unfortunately Rakke et al. (2011) do not recognize this point and their work is not clear on the reason why they have considered this kind of sales in their problem and whether these sale decisions are considered to be real or not .

Looking at the liquefaction phase of an LNG supply chain where the production of LNG occurs (discussed in 2.3.2), it can be seen that in this phase, natural gas is pre-treated, its NGL are removed, then it is liquefied and stored in the LNG production plant/terminal until it is loaded to tankers, (see Figure 2.3). The pre-treatment, removal of NGL and liquefaction of natural gas occurs in the Trains (see Figure 2.5), while storage is carried out in the tank-farm of the LNG production terminal. This means that the liquefaction

[1] An uncommitted product sale is a spot sale; but this is not often stated in the rest of this thesis when the 'uncommitted product sales' phrase is used as it would be redundant; same is for arbitrage.

phase consists of two main segments: firstly, pre-treating, removal of NGL and liquefying, and secondly, storage.

With regards to pre-treating, removal of NGL and liquefying of natural gas it should be noted that liquefaction plants are very expensive projects and the assumption in developing and running these plants, like the other production units in maritime IRPs, is that the Trains are working with full capacity all the time, unless they are turned-off for an overhaul for a predefined time or there is an unexpected failure (Rakke et al., 2011). Rarely, political unrest can also stop the flow of LNG in a liquefaction plant; this factor, due to its rarity, is not considered in this research. In the case of an overhaul or an unexpected failure the LNG output of a Train stops/decreases. Neither overhaul, which is carried out in regular intervals, nor failure are factors controlled by the LNG producer. Therefore, these two factors plus the full LNG production capacity of the Trains are all inputs in the calculations of the producer. In brief, the LNG output of the Trains is their total capacity minus the reductions as a result of overhaul or failure, should either of these occur; and this output is not part of the decision-making by the LNG producer.

With regard to the tank-farm of the LNG liquefaction terminal; it is a storage facility where LNG flowing from the Trains is stored until it is loaded onto the LNG tankers. This is a textbook inventory management problem (see Section 3.1) in which the flow of product in and out of the tank-farm should be dealt with in a way that permits the smooth operation of the LNG production and distribution project, considering the tank-farm costs and tank-farm constraints such as its capacity. In summation, the total liquefaction phase of the LNG supply chain, including the Trains and tank-farm, is reducing to and should be modelled as an inventory management problem.

With regards to LNG shipping, it can be seen from Chapter 2 that the bulk of LNG is sold to buyers on LTCs, either traditional LTCs or a self-contracts, with CIF/DES deliveries[1]; this means that the LNG producers needs to plan and transport the LNG to the buyer's principally identified regas terminal with their own fleet. Apart from CIF/DES-LTC deliveries[2], as reminded in the beginning of this chapter, there are uncommitted product sales and arbitrage that in occurrence are carried out by the LNG producer. It should be said that in terms of shipping operations for the producer, self-contracts and traditional LTCs with CIF/DES deliveries are the same, just arbitrage (according to 2.4.2) occurs more frequently in self-contracts. Shipping of LNG by the LNG producer is a matter of distributing LNG to the CIF/DES-LTC buyers in their regas terminals while using opportunities for uncommitted product sales and arbitrage all with the LNG producer's tanker fleet. The goal in shipping for the LNG producer logically is minimization of distribution costs and maximization of revenue. This is the explanation for a VRP (as previously defined in Section 3.1) and, as such, the shipping of LNG shall be modelled as a VRP.

The fact that both of these steps, liquefaction and shipping, are managed by the LNG producer implies the need for coordinated running of these phases; the harmonized running of liquefaction (an inventory management problem) and shipping (a VRP) forms an IRP, and given the context, a maritime IRP. This problem – as seen throughout this chapter – has all the main features of a maritime IRP as described at the beginning of Section 3.2. In this maritime IRP the costs in tank-farm and tanker fleet management are minimized while the revenue from deliveries is maximized; these are the costs and

[1] It is mentioned in Chapter 2 that there are traditional LTCs with FOB deliveries as well, where the LNG buyer sends his own tankers to off-take the LNG in the LNG liquefaction plant. These cases of LTCs are considered later and their effect on the model developed is taken to account.

[2] For simplicity, an LTC buyer of LNG on a self-contract or traditional LTC with CIF/DES deliveries, is named a CIF/DES-LTC buyer and his and his deliveries are CIF/DES-LTC deliveries. While an LTC buyer with FOB deliveries is named an FOB-LTC buyer and his deliveries are FOB-LTC deliveries.

revenues which are considered in the VRP and inventory management problem discussed. It is shown later in this chapter that a specific perspective towards these cash flows maximizes the profit of the LNG production and distribution project at the operational level. Figure 4.1 portrays the LNG liquefaction and shipping problem in the LNG supply chain.

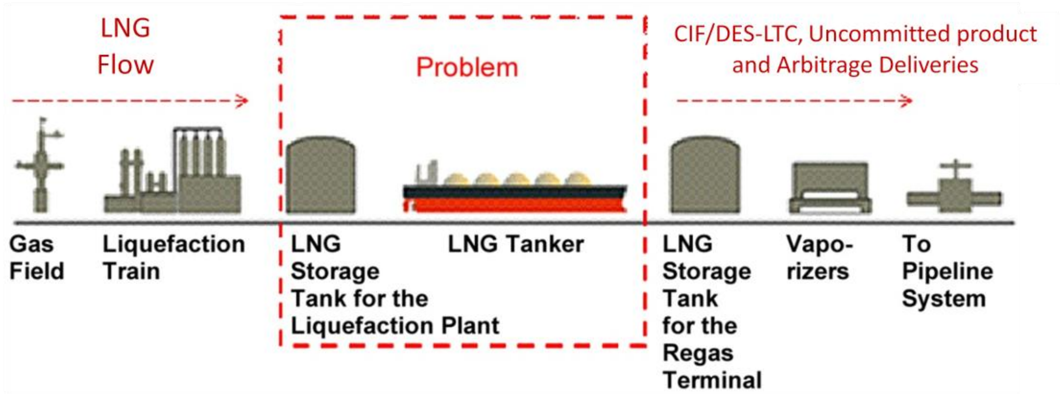


Figure 4.1 - The LNG production and distribution problem

In the rest of this chapter, initially, the research problem is explained in detail (4.2), then the structure of costs and revenues for the problem are discussed (4.3), and, ultimately, the model is presented (4.4).

4.2. Problem explanation

The problem considered in this research is the operational cargo delivery planning and inventory management for an LNG project. In this problem both types of demand/delivery for the LTC buyers: CIF/DES and FOB as the result of traditional LTCs and self-contracts are taken into account. Changes in LTC demands and operational requirements are incorporated in planning for the problem in practice. Arbitrage is permitted with mutual agreement of both LTC sides and there are two types. Arbitrage type one, which is suggested by the LNG producer where he needs to replace the arbitraged LNG cargos for the CIF/DES-LTC buyer (arbitrage is defined for LTCs with a destination clause, that according to 2.4.3, are traditional LTCs and self-contracts with CIF/DES deliveries), and type two, which can be suggested by any party but without any replacement responsibility for the LNG producer. Surplus LNG, uncommitted product, can be sold OTC and on spot; genuine spot sales are considered for this problem.

A fleet of heterogeneous tankers is controlled by the LNG producer. The fleet consists of two types of tankers; fixed tankers, which are owned or long-term contracted by the LNG producer and spot tankers, which are spot chartered for one trip. Tankers leave the LNG production terminal full and deliver their whole cargo to a regas terminal. Need for a specific fixed tanker for a CIF/DES-LTC delivery, which may be designated in the ADP, or unavailability of fixed tankers due to pre-planned activities, such as dry-docking, can be defined as extra constraints for the problem. Fixed tankers can be used for all uncommitted product, arbitrage and CIF/DES-LTC deliveries, unless contractually forbidden. Therefore, a spot tanker is only hired when there is no available or proper fixed tanker, as spot chartering is expensive. Spot tankers can be used for transporting all CIF/DES-LTC, arbitrage and uncommitted product cargos to any regas terminal. Each tanker has its own specific capacity and travelling speed. The position of each fixed tanker at the beginning of the problem can be a port or a place at sea. There are limited numbers of berths available at the LNG production terminal, therefore, if a tanker arrives when there is no free berth it has to stay at anchor.

The goal of modelling in the research problem, as stated before, is profit maximization for the LNG producer in operational planning. Profit, given the level of planning in LNG liquefaction and shipping, composes of two parts; a part that is controlled and a part that is not controlled by the LNG producer.

The uncontrollable part of the profit comes from the costs and revenues that are independent from the decisions that the LNG producer makes in the day-to-day running of the LNG project. Given the segments of the liquefaction plants discussed in the previous section, all the costs of the Trains plus the capital and periodic maintenance costs of the tank-farm are not decided by the LNG producer in practice. Looking at the tankers in the LNG industry, there are costs that are not related to operational decision-making. In this research these expenses are named non-operational costs, in contrast to operational costs. Tanker costs are a rather complicated topic and separating these costs into operational and non-operational necessitates an extensive discussion; this is carried out in the next section. With regards to revenues, the time and volume of LTC deliveries (both FOB and CIF/DES) related to demands of LTC buyers are fixed and established in the ADP and any change in the time and volume of them is decided mutually between the LNG producer and the LTC buyers by negotiation and before operational planning; in planning these changes are put into practice (Flower, 2010).There is a limit to the extent to which LNG producers can respond to the changes in demand and the respective deliveries, bounded usually by product availability and logistical constraints (the model developed, evaluates the feasibility of the changes agreed upon).The revenue of these deliveries, which are compulsory, is determined by the price clause of the LTC, given the decided delivery time of them. There is just one exception in fulfilling LTC demands where a CIF/DES-LTC delivery or a portion of it is not carried out, rather it is arbitraged. Given this discussion it is argued that related to self-contracts and traditional LTCs on the project, the revenue of the CIF/DES-LTC deliveries which are carried out – not arbitraged – plus FOB deliveries are independent from the decisions of the LNG producer in operational planning. This is because neither the volume of these deliveries, which in the case of CIF/DES deliveries is the remainder of the deliveries minus the portion that is arbitraged, nor the time or the price are decided by the LNG producer in operational planning.

The controllable part of the profit comes from the operational tanker and tank-farm costs plus the revenues from uncommitted product sales and arbitrage. These are the costs and revenues that are decided in operational planning, hence, are of interest in this research and should be considered in the formulation of the IRP. Therefore, in the second paragraph of page 85 (continues to page 86), given the level of planning in this research, the minimization of tank-farm and tanker costs in the IRP focuses on the operational part of these costs, and the maximization of revenues on uncommitted product sales and arbitrage. As a result of the discussion of this paragraph, the model developed in the remainder of this chapter maximizes the controllable part of the profit in liquefaction and shipping of LNG.

4.3. Time value of money and controllable and uncontrollable costs and revenues

The magnitude of cost and revenue cash flows in the LNG sector motivates consideration of the time value of money in running the projects. Money has a time value because of the opportunity to earn interest or the cost of paying interest on borrowed capital; this means a dollar received today is worth more than a dollar received at some future time. Logically all revenues should be received as soon as possible while all costs should be postponed as long as possible. The present value of a set of cash flows therefore depends on the timing of costs and revenues along with the discount or interest rate. Formula (1) relates present and future values:

PV is the present value at time 0

FV is the future value at time t

r denotes the nominal interest rate per period

m denotes the number of times the interest is compounded per period, also known as the compounding frequency

t denotes the number of periods, not necessarily an integer

$$PV = \frac{FV}{(1 + \frac{r}{m})^{mt}} \tag{1}$$

To discount the interesting costs and revenues of the controllable part of the profit, for the problem discussed in Section 4.2, the nature and structure of the relative cash flows should be examined and a time for each shall be defined.

Operational tank-farm costs: there is a daily operating cost related to keeping and reserving LNG in the tank-farm of the LNG production plant. This cost comes from elements such as workers' wages. The operating cost should be considered and discounted in the model.

Operational tanker costs: to identify operational and non-operational expenses for tankers it should be noted that total expenditure related to each tanker consists of four parts. Firstly, capital costs including payments to the shipyard, banks and equity bearers, and also scraping. Secondly, periodic maintenance costs related to dry docking and surveys. Thirdly, operating costs generated by the crew's salary, stores and consumables, routine repairs, insurance and, in some cases, administration fees. Finally, voyage costs created as a result of the purchase of fuel, port charges and canal dues (Stopford, 1997).

There are two types of tankers in service in the LNG production and distribution projects: owned or long-term contracted fixed tankers and spot tankers. After studying the LNG market and consulting experts it is understood that in long-term contracting

LNG tankers the main types of agreement are time and bareboat charters while for one-off trips/spot tankers the voyage charter is the main contract (Flower, 2010).

With regard to owned fixed tankers all the tanker costs are paid by the LNG producer and the producer manages and operates the tanker. Of the aforementioned four categories of costs, the operating and voyage costs depend on the tanker schedule that is decided in operational planning while the rest are independent. Therefore only dependent expenses need to be considered in profit maximization in this research.

For time chartered fixed tankers only voyage costs are paid by the charterer and the other tanker expenses are paid by the tanker owner who operates the tanker. In this type of contract, the charter rate is normally an agreed fee per day, as used in this thesis, but can be per month or year, which in the case of tanker long-term contracts is typically made up of two elements. Firstly, a fixed amount which covers the cost of the ship owner, i.e. capital repayments, financing plus owner's margin; and secondly, a variable fee covering operating costs of the owner including crew, insurance, administration fees, etc. (Flower, 2010). According to this explanation, the expenses which are important in operational decision-making in time charters are voyage costs and the variable element of the chartering rate covering the operating costs of the tanker owner.

For fixed tankers with bareboat charters, only the capital cost is the responsibility of the ship owner and he receives a fixed charter rate. All other tanker costs are paid by the charterer who operates the tanker. Of the costs which are the charterer's responsibility, voyage and operating expenses are related to the tanker schedule hence they are considered in profit maximization.

In summary, the important expenses in profit maximization in practice related to the fixed LNG tankers are voyage and operating costs. Combined, they make the operational tanker costs cited in the previous section for fixed tankers. In detail, these expenses consist of the following components: administration fee, crew salary, stores and consumables, routine repairs, insurance, fuel, port charges and canal dues. To consider the time value of each of these elements a time should be assigned to the cash flow generated by each. Therefore they are clustered in four different categories in Table 4.1.

Table 4.1 - Time assignment to cost elements*

	Loading & outgoing (outward) leg		Unloading and returning (return) leg	
	When loading	When steaming	When unloading	When steaming
Tanker costs	Administration fee, Crew salary, Stores & consumables, Routine repairs, Insurance, Fuel, Port charges	Canal dues	Stores & consumables, Routine repairs, Fuel, Port charges	Canal dues

* Administration fee, paid to the tanker owner for operating the tanker, is just related to the tankers with time chartering contracts and it is zero for bareboat chartered and owned tankers.

Finally, voyage charter contracts used for tanker spot chartering in the LNG industry are based on $/tonne, $/MMBtu or may just be an agreed amount for a particular voyage (Flower, 2010). All tanker costs for this type of hire are paid by the tanker owner who operates the ship. It is assumed in this thesis that the whole amount of the voyage charter fee – the operational cost of spot tankers for the LNG producer – is paid to the tanker owner at the beginning of the trip.

Revenue in uncommitted product (spot) sale: a positive cash flow is generated and received by the LNG producer as the result of selling uncommitted LNG OTC, which is assumed to be realized on the day the LNG is delivered to the buyer.

Revenue of (spot sale in) arbitrage: in optimizing and evaluating arbitrage decisions, the revenue difference in cargo arbitrage, also known as arbitrage revenue, should be considered. This is the extra income which the LNG producer receives in arbitraging a cargo that was supposed to be delivered to the regas terminal of a CIF/DES-LTC buyer (in a self-contract or traditional LTC) and instead is redirected to a new regas terminal/market which suggests a higher price. In an arbitrage with a commercial driver (as discussed in 2.4.3) this extra income that results in a higher profit is the main cause of arbitrage. It is assumed that the LNG producer makes his decisions for arbitrage based on this extra income. The income is received upon delivery of the arbitraged cargo to the new regas terminal.

An arbitrage due to a commercial driver while infrequent may occur without having the new market offering a better price – it may even suggest a lower price – in other words without any extra income. In such a case the new market may be so close that the tanker costs in transferring the LNG to this market/regas terminal is much cheaper than delivering to the principally identified regas terminal of the CIF/DES-LTC buyer (in a self-contract or traditional LTC). Considering the amount which the LNG producer is paid in delivering LNG to each of the regas terminals and cost of transferring LNG to these terminals, the LNG producer may find arbitraging the LNG to the new market more profitable.

Although rare there are arbitrages with other reasons than a higher profit for the LNG producer; these are arbitrages with operational drivers (Zhuravleva, 2009). Here, causes such as a regas terminal outage or an embargo make delivery to the reags terminal of the CIF/DES-LTC buyer impossible and hence the arbitrage. This kind of arbitrage, which in contrast to arbitrages with commercial incentives is not a matter of choice for the LNG producer, is not covered by the model developed.

Given the types of arbitrage defined in the previous section, if the LNG producer needs to replace the arbitraged cargo for the CIF/DES-LTC buyer, then to calculate the arbitrage revenue the cost of cargo replacement should be deducted from the extra income gained in the arbitrage of that cargo. It is assumed that the LNG producer pays for the replacement upon its delivery to the CIF/DES-LTC buyer's regas terminal.

The reader should note that the times assigned to the costs and revenues discussed in this section are typical ones which may vary by project. As a result, the formulation may need to be slightly modified for each new project.

4.4. Problem formulation

Having explained the premise of the problem and discussed the structure of costs and revenues, we can now proceed with the formulation of a mathematical model for the maximisation/optimization of the controllable profit component. The formulated model is an MIP one. Maritime IRPs, given the type of decisions associated with them, are generally modelled as MIPs (Christiansen and Fagerholt, 2009). The model contains four decision-variables, including: I_h – the tank-farm level; X_{htd} – decision on uncommitted product (spot) sale; Y_{htd} – decision on CIF/DES-LTC deliveries (for self-contracts and traditional LTCs) and Z_{htdvs} – decision on (spot sale in) arbitrage. Of these four the first one is a decision-variable with continuous values while the rest, due to the nature of choices in the problem which are yes or no, can assume only zero/no and one/yes values. Decision-variables with zero and one values are called binary variables (Hillier and Lieberman, 2010).

In optimization problem the set of constraints defines a feasible solution space, also known as the set of candidate solutions, for the model and the goal is finding the best/optimum solution in that space so that the objective function is optimized. A solution in an optimization problem is a set containing values for all the decision-variables which satisfies all the constraints (Taha, 1992).

At this point it is interesting to note that an MIP problem is categorized as a discrete optimization problem, in contrast to a continuous optimization problem. A discrete optimization problem is a problem in which all or some of the decision-variables assume discrete – in contrast to continuous – values. An MIP problem is a discrete optimization problem since some of its decision-variables have to assume integer values (Taha, 1992).

Models in maritime IRPs do not build on each other and every new piece of work presents and develops its own model, given its assumptions and conditions, hence almost every new paper produces a new version of an IRP (Song and Furman, 2013). Therefore, as stated in the previous chapter, relating these separate works to one another is very difficult. However, given the characteristics identified for maritime IRPs in Table 3.1, the problem described in Section 4.2 can be said to be, in terms of routing and topology, a direct and one-to-many research problem, respectively.

Having direct routing/delivery means that in contrast to problems with multiple routing, there is no need to consider partial delivery in the modelling. Partial delivery could add two main factors to the model. With direct delivery, as in this research, a vessel is dispatched from the production plant to a regas terminal and, hence, its trip consists of two legs: outward and return (like Shen et al., 2011), however, with partial delivery the trip has more than two legs as more than one point must be visited. This adds the problem of choosing between several potential visiting points after the first stop, which adds one dimension to the decision-variable on routing the vessels. Apart from this, with partial delivery, the portion of the cargo on board a vessel allocated to each point visited, needs to be defined as a decision-factor.

It is interesting to note that modelling problems with a one-to-many topology and direct delivery scheme (such as Rakke et al., 2011; and Halvorsen-Weare and Fagerholt, 2013) is simpler than modelling problems with a many-to-many topology and the same delivery scheme. This is because, with the latter, although there is no partial delivery (since there is more than one option for reloading a vessel after a service) the extra dimension to the routing of the vessel – as discussed in the previous paragraph – does need to be introduced. Problems with many-to-many topologies (as in Christiansen and Nygreen, 1998a, 1998b; and Song and Furman, 2013) become even more complex with partial delivery since here the cargo allocation to ports visited becomes a decision-factor. In such networks the vessel does not necessarily unload all of its cargo before visiting a production port, rather it may reload before it has been fully unloaded.

The discussions of the last two paragraphs are for cases with only one product; the model becomes increasingly complicated with several products. With several products, which are essentially non-mixable onboard a ship, there is the matter of defining compartments for each vessel. A compartment allows a product to be carried separately from other products. In some maritime problems the compartments are product specific meaning only a specific product can be carried in a specific compartment (as in Al-Khayyal and Hwang, 2007). However, there are cases with inclusive compartments too; in these problems a decision-variable for matching the products and compartments for the vessels, given the demand of the customer ports, should be embodied within the model (as in, e.g. Dauzère-Pérès et al., 2007; and Christiansen et al., 2011). In addition to this, having several products, inventory management becomes more difficult, as separate inventories for each product need to be defined in a port (as in, e.g. Ronen, 2002; Shih, 1997; and Miller, 1987). The LNG production and distribution problem in this research focuses only on one product, LNG, hence does not deal with any of these complexities.

The inventory focus of the problem in this research is only the production plant (one-side). In this research, as in Halvorsen-Weare and Fagerholt (2013) and Rakke et al.

(2011), it is assumed that if a market has shown interest in an uncommitted product sale then there is enough inventory capacity for the vessels dispatched to that market. The same is assumed for arbitrage. Apart from this, given the deliveries agreed for the LTC buyers, it is taken for granted that LTC buyers with CIF/DES deliveries have arranged for the tank-farm capacity when their LTC deliveries arrive. Hence, there is no need for concern over the inventory at the delivery ports. It should be mentioned that problems, where the decision-maker controls inventories at both consumption and production ends, arise when VMI is practiced in the system (e.g. Christiansen et al., 2011). In VMI the producer monitors the inventory of the consumers and reloads for them at the appropriate time, given his constraints. It is argued that by using the VMI practice, factors such as the utilization of transport capacity increases (Kleywegt et al., 2002). VMI can be implemented with focus only on the inventory of the consumer, too (e.g. Shen et al., 2011 or Miller, 1987). The inventory management mode in this research, as in e.g. Al-Khayyal and Hwang (2007), is fixed; this is discussed in 4.4.1.2, in piece entitled 'penalty of fall in the safety stock level'.

Model indices (alphabetically)

Index	Definition
d = 1, …, PD	CIF/DES-LTC destinations and uncommitted product destinations. CIF/DES-LTC destinations are d = 1, …, CD and uncommitted product destinations are d = 1, …, PD
f = 1, …, PF	The number of cost clusters for fixed tankers
h = 1, …, PH	Days of the period of time studied
s = 1, 2	Arbitrage types
t = 1, …, PT	Tankers. All the tankers are t = 1, …, PT; fixed tankers are t = 1, …, FT and spot tankers are t = FT+1, …, PT
v = 1, …, PV	Arbitrage destinations

In defining parameters and decision-variables used in the problem, six indices are used, including; d for defining the CIF/DES-LTC regas terminals/destinations and uncommitted product destinations, f for defining the cost clusters for fixed tankers, h for defining the days of the period of time studied by the model, s for defining the types of arbitrage, t for specifying the tankers and v for defining the arbitrage regas terminals/destinations.

d: the set of CIF/DES-LTC destinations for the period studied in the formulation are indexed as d = 1, …, CD; these are the principally identified regas terminals of the CIF/DES-LTC buyers (in traditional LTCs and the self-contracts) where the LNG is delivered (essentially each CIF/DES-LTC buyer is specified with a regas terminal).

The uncommitted LNG, sold OTC, can be sold to several buyers; the buyers that receive the uncommitted product at their respective regas terminal/destination in the period studied are indexed as d = 1, …, PD. $PD \geq CD$. This means that the set of potential destinations for the spot sale of uncommitted product, named uncommitted product destinations, includes the CIF/DES-LTC destinations; in other words every CIF/DES-LTC destination can also be an uncommitted product buyer. In the formulation whenever the range of *d* is not mentioned – the upper and lower bounds of *d* are not declared in summations – the larger range of d (= 1, …, PD) is used.

f: analysis of the costs of fixed tankers – both owned and long-term contracted – resulted in clustering these costs given the time they occurred in order to consider the time value of money factor (Table 4.1). These clusters in the period studied are indexed as f = 1, …, PF. The range of f for the sake of simplicity is not mentioned in the formulation.

h: the model maximizes the controllable part of the profit over a finite period of time. In operational decision-making in the LNG sector, the producers usually plan two to three months ahead (Rakke et al., 2011). The period planned, with days as its units, in the formulation is indexed as h = 1, …, PH. Like the previous index the range of h is not mentioned in the formulation for simplicity.

s: given the need for cargo replacement by the LNG producer in arbitrage two types of arbitrage were defined in Section 4.2, with (type 1), and without replacement (type 2).

Arbitrage is indexed as s = 1, 2 but the range is not mentioned in the formulation for simplicity.

t: according to Section 4.2 two types of tanker are defined for the problem modelled; spot tankers and fixed tankers. While fixed tankers are indexed as $t = 1, \ldots, FT$ the spot tankers in the period studied are indexed as $t = FT+1, \ldots, PT$. The combination of both spot and fixed tankers in the period is indexed as $t = 1, \ldots, PT$. In the formulation whenever bounds of t in summations are not mentioned the larger range of t (= $1, \ldots, PT$) is used.

v: in the period studied there are a set of destinations – representing buyers – which are interested in and pay for the arbitraged cargos. These destinations, that include some or all of the uncommitted product destinations defined under index d, in the formulation for the period studied, are indexed as $v = 1, \ldots, PV$. The range is not mentioned in the model to keep the formulation clean and simple.

In defining the option of doing or not doing an arbitrage in the form of a decision-variable (Z_{htdvs}), both defined CIF/DES-LTC and arbitrage destinations are used. In differentiating these two destinations, it helps to have a different index for CIF/DES-LTC and arbitrage destinations. Defining both of these destinations with the same index may cause confusion, and furthermore it would make computer programming difficult.

Model parameters (alphabetically)

Parameter	Definition
CA_t	Capacity of tanker t in cubic-meters
CS	Cost of safety stock level fall in the tank-farm of the LNG production plant for each cubic-meter of LNG
CT_{htdf}	Cost of transferring LNG from the LNG production plant to CIF/DES-LTC or uncommitted product destination d by a fixed tanker t which leaves on day h
CT_{htvf}	Cost of transferring LNG from the LNG production plant to arbitrage destination v by a fixed tanker t which leaves on day h
CY	Compounding frequency
DD_{hd}	CIF/DES-LTC demand/delivery, in tonnes, that should be fulfilled on day h and transported by the fleet of the LNG producer to CIF/DES-LTC destination d

DE	Density of LNG usually between 0.41 to 0.5 tonnes/cubic-meters
DI_{hdvs}	Extra income of the LNG producer in arbitrage of a tonne of LNG from CIF/DES-LTC destination d to arbitrage destination v with arbitrage type s that is dispatched on day h
DP_h	FOB-LTC demand/delivery, in tonnes, which is taken from the production plant by the FOB-LTC buyer fleet on day h
HH_{td} $=H1_{td}+$ $H2_{td}$	Travelling time, in days, from the LNG production plant to CIF/DES-LTC or uncommitted product destination d by tanker t. This includes both outward ($H1_{td}$) and return times ($H2_{td}$)
HH_{tv} $=H1_{tv}+$ $H2_{tv}$	Travelling time, in days, from the LNG production plant to arbitrage destination v by tanker t
IB	Volume of LNG, in cubic-meters, in the tank-farm of the LNG production plant at the beginning of period
IC_h	Inventory cost for one cubic-meter of LNG on day h in the LNG production plant
IR	Nominal annual interest rate
LV_{hd}	Proportion of DD_{hd}, as a scale of 1 to 100, that the relative CIF/DES-LTC buyer is ready to arbitrage
MI_1	Minimum permitted stock level, in cubic-meters, in the tank-farm of the LNG production plant
MI_2	Safety stock volume, in cubic-meters, in the tank-farm of the LNG production plant
MI_3	Capacity, in cubic-meters, of the tank-farm of the LNG production plant
MT_0	Capacity in cubic-meters, of the maximum tanker servable in the LNG production plant berths
MT_d	Capacity, in cubic-meters, of the maximum tanker servable in CIF/DES-LTC or uncommitted product destination d
MT_v	Capacity, in cubic-meters, of the maximum tanker servable in arbitrage destination v
NB	Number of berths in the LNG production plant
NP_h	Number of tankers of FOB-LTC buyers in the LNG production plant arriving on day h
PP_h	Production of LNG, in tonnes, in the LNG production plant on day h
RT_{tdf}	Realization time of a cost cluster of fixed tanker t dispatched to CIF/DES-LTC or uncommitted product destination d with cost clustering f
RT_{tvf}	Realization time of a cost cluster of fixed tanker t dispatched to arbitrage destination v with cost clustering f
SC_{htd}	Spot chartering cost of spot tanker t leaving on day h for CIF/DES-LTC or uncommitted product destination d
SC_{htv}	Spot chartering cost of spot tanker t leaving on day h for arbitrage destination v
SP_{hd}	Spot price of a tonne of LNG dispatched to uncommitted product destination d on day h
UP_{hds}	Replacement cost for a tonne of arbitraged LNG – with an arbitrage type s – received in CIF/DES-LTC destination d on day h
UT_{ht}	Unavailability of tanker t on day h due to being late or not in service

Model functions (alphabetically)

Function	Definition
$\boldsymbol{F(x,y) = 2\,PD\,x\,(PV+\ 1)\,y}$	Functions assisting in simplifying fixed tankers service constraint (equation number 11)
$\boldsymbol{G(y-1) = \sum_{a=0}^{y-1}\sum_{d} X_{(h+a)td} + \sum_{a=0}^{y-1}\sum_{d=1}^{CD} Y_{(h+a)td} + \sum_{a=0}^{y-1}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{(h+a)tdvs}}$	
$\boldsymbol{H(y) = 2\,PD\,y\,(PV+\ 1)+1}$	
$\boldsymbol{J(x) = \left(1+\frac{IR}{CY}\right)^{CY\left(\frac{h+x}{365}\right)}}$	Discounting factor

Model decision-variables (alphabetically)

Decision-Variable	Definition
I_h	Volume of LNG, in cubic-meters, in the tank-farm of the LNG production plant at the end of day h
X_{htd}	An uncommitted product delivery carried out by tanker t to uncommitted product destination d, leaving the LNG production plant on day h
Y_{htd}	A CIF/DES-LTC delivery carried out by tanker t to CIF/DES-LTC destination d leaving the LNG production plant on day h
Z_{htdvs}	An arbitrage delivery, that was to be dispatched to CIF/DES-LTC destination d, carried out by tanker t to arbitrage destination v leaving the LNG production plant on day h

The model below is complicated, hence, to aid in understanding it, different blocks of it are narrated and constructed separately. The blocks are explained in six parts: objective function (4.4.1), inventory constraints (4.4.2), CIF/DES-LTC demands/deliveries fulfilment constraint (4.4.3), arbitrage constraints (4.4.4), berthing service constraints (4.4.5), tanker assignment constraints (4.4.6) and binary constraints (4.4.7). Following the formulation a few points on the model programming and running are discussed (4.4.8).

4.4.1. Objective function

The model as discussed in Section 4.2 focuses on the controllable part of the profit and considers costs and revenues for that part of the profit only; this is the objective of the modelling. As such the operational costs in shipping (4.4.1.1) and storage (4.4.1.2) of LNG are minimized and the revenues for uncommitted product sales (4.4.1.3) and in arbitrage (4.4.1.4) are maximized.

4.4.1.1. Operational shipping/tanker costs

The cost of two different types of tanker, i.e. fixed and spot, used in shipping the arbitrage, uncommitted product and CIF/DES-LTC deliveries for the LNG project should be considered in the calculations.

Cost of fixed tankers: in undertaking a trip by a fixed tanker the cost determined in Section 4.3 is the responsibility of the LNG producer. This cost needs to be considered in the resulting mathematical model.

Assuming that fixed tanker t can be assigned to a CIF/DES-LTC delivery, because of a self-contract or a traditional LTC, to CIF/DES-LTC destination d leaving the LNG production plant on day h. This decision in the formulation is shown with decision-variable Y_{htd}; if the tanker is assigned then this decision-variable would be one, otherwise it is zero. The components of a fixed tanker cost for a trip undertaken are outlined and typically clustered in Table 4.1. The magnitude of the cost cluster f for fixed tanker t that is leaving the LNG production plant on day h for destination d in the formulation is denoted by CT_{htdf}.

The purpose of cost clustering allows the time value of money to be considered in decision-making; this factor can be entered into the formulation by formula (1), as discussed in the last section. In using this formula the timing of cash flows is important; hence, in order to consider the time value of money with regards to fixed tanker costs the timing of cost clusters for these tankers needs to be defined. The timing – from the beginning of the trip – of cost cluster f for fixed tanker t leaving from the LNG production plant for destination d is shown in the formulation by RT_{tdf}.

The time value of money factor is meant to be taken into account for all the costs and revenues of the LNG project; in doing so all of these cash flows need to be discounted to a specific point in time. This would determine the controllable part of the profit under a different set of decisions, which results in picking the best set of decisions/strategy that maximizes that part of the profit. The model maximizes the controllable part of the profit for a period; a convenient point in time for discounting the costs and revenues would be the beginning of this period. Therefore, if a fixed tanker is assigned to a

CIF/DES-LTC delivery (Y_{htd} = 1) then the discounted value of a single cost cluster (CT_{htdf}) for it, with timing RT_{tdf} would be $\frac{CT_{htdf}\, Y_{htd}}{(1+\frac{IR}{CY})^{CY(\frac{h+RT_{tdf}}{365})}}$. IR and CY are the annual nominal interest rate and the compounding frequency, respectively. For the sake of simplicity the phrase $(1+\frac{IR}{CY})^{CY(\frac{h+x}{365})}$ in the formulation is shown as $J(x)$, hence the discounted cluster cost is written as $\frac{CT_{htdf}\, Y_{htd}}{J(RT_{tdf})}$. Considering all the cost clusters, CIF/DES-LTC destinations, fixed tankers and days for a period, the discounted fixed tanker cost for CIF/DES-LTC deliveries is written as $\sum_h \sum_{t=1}^{FT} \sum_{d=1}^{CD} \sum_f \frac{CT_{htdf}\, Y_{htd}}{J(RT_{tdf})}$.

The discounted fixed tanker cost for uncommitted product (X_{htd}) and arbitrage (Z_{htdvs}) deliveries can be derived in the same way as for CIF/DES-LTC deliveries. Hence, in the formulation the cost of assigning fixed tankers for deliveries to all CIF/DES-LTC, uncommitted product and arbitrage destinations is written as $\sum_h \left\{\sum_{t=1}^{FT} \sum_d \sum_f \frac{CT_{htdf}\, X_{htd}}{J(RT_{tdf})} + \sum_{t=1}^{FT} \sum_{d=1}^{CD} \sum_f \frac{CT_{htdf}\, Y_{htd}}{J(RT_{tdf})} + \right.$
$\left. \sum_{t=1}^{FT} \sum_{d=1}^{CD} \sum_v \sum_s \sum_f \frac{CT_{htvf}\, Z_{htdvs}}{J(RT_{tvf})} \right\}$.

Cost of spot tankers: in the same way as for fixed tankers, the cost of spot chartering tankers, defined in Section 4.3, should be taken to account. Imagine that a spot tanker t can be assigned for an arbitrage delivery by redirecting an LNG cargo from CIF/DES-LTC destination d to arbitrage destination v by an arbitrage type s, leaving on day h; this decision in the formulation is shown by Z_{htdvs}. If the tanker is assigned for such an arbitrage then this variable would be one, otherwise it would be zero.

The cost occurring as the result of the trip carried out by the spot tanker t leaving on day h for arbitrage destination v in the formulation is shown as SC_{htv}. It was discussed in the previous section that in this research it is assumed that all the costs of spot tankers are paid at the beginning of the trip, hence, considering the time value of money the discounted spot tanker cost at the beginning of the period would be $\frac{SC_{htv}\, Z_{htdvs}}{(1+\frac{IR}{CY})^{CY(\frac{h}{365})}}$; using the $J(x)$ function this phrase can be written as $\frac{SC_{htv}\, Z_{htdvs}}{J(0)}$. Considering all the arbitrage types, arbitrage destinations, CIF/DES-LTC destinations, spot tankers and days of the period, the discounted spot tanker cost for arbitrage deliveries is written as $\sum_h \sum_{t=FT+1}^{FT+ST} \sum_{d=1}^{CD} \sum_v \sum_s \frac{SC_{htv}\, Z_{htdvs}}{J(0)}$.

The spot tanker cost for uncommitted product and CIF/DES-LTC deliveries can be derived in the same way as for arbitrage deliveries. Hence, in the formulation the cost of CIF/DES-LTC, uncommitted product and arbitrage deliveries by spot tankers is written as:

$\sum_h \left\{\sum_{t=FT+1}^{FT+ST} \sum_d \frac{SC_{htd}\, X_{htd}}{J(0)} + \sum_{t=FT+1}^{FT+ST} \sum_{d=1}^{CD} \frac{SC_{htd}\, Y_{htd}}{J(0)} + \sum_{t=FT+1}^{FT+ST} \sum_{d=1}^{CD} \sum_v \sum_s \frac{SC_{htv}\, Z_{htdvs}}{J(0)}\right\}$.

4.4.1.2. Tank-farm costs

Two types of costs are assumed for the tank-farm, the operating cost of keeping LNG at the tank-farm and the penalty of a fall in the safety stock level.

Operating cost: a daily operating cost occurs at the tank-farm of the LNG production plant (Section 4.3). In the formulation the volume of LNG stored in the tank-farm for day h, is shown as I_h. The cost of storing one cubic-meter of LNG on day h is IC_h; considering the time value of money and given the fact this cost occurs daily, this cost is discounted as $\frac{IC_h\, I_h}{J(0)}$. By considering all the days of the period the cost of operating the tank-farm would be $\sum_h \frac{IC_h\, I_h}{J(0)}$.

Penalty of a fall in the safety stock level: when there is a failure/an unexpected problem in the Trains of the LNG liquefaction plant and the LNG outflow of the Trains decreases or stops; in order to satisfy the LTC demands in self-contracts and traditional LTCs and carry out the respective deliveries, which should be fulfilled under any circumstances, in some LNG liquefaction terminals a specific volume of product named the safety stock volume is kept in the tank-farm. There is no need to mention that reduction in the output of the Trains because of an overhaul is pre-planned and known in advance hence is considered in planning and deciding the FOB and CIF/DES deliveries in LTCs. The magnitude of this safety stock volume, which is supposed to compensate for the liquefaction Trains until they return to service, depends reasonably on the output of the LNG plant, the reliability of the Trains and their average fixing time. Due to the confidentiality of operational instructions in liquefaction plants it has not been possible to provide a typical size for the safety stock volume.

Rationally, the safety stock volume would be kept in LNG liquefaction terminals with considerable inventories. If the LNG liquefaction terminal is relatively small and does not have a large inventory then in the case of a failure in the Trains the LNG producer replaces the LTC deliveries with gas cargos from gas markets. This cost is not considered in the model, and an LTC demand which is satisfied with such an arrangement is out of the scope of this formulated MIP, and should not be considered in the model after being identified. This means the tank-farm of the production plant will always have enough LNG to fulfil its self-contract and traditional LTC obligations and hence, the inventory management scheme for it would be fixed.

Under normal circumstances, when the liquefaction plant is working properly, the tank-farm level should not fall below the safety stock volume level, and to avoid this, a penalty is determined for breaching that level. This is not a real cost, hence, is not discussed in Section 4.3 as it merely helps the model developed to consider the concept of the safety stock volume. This penalty is assumed to occur on the day that the level of LNG stored falls below the safety stock level.

In calculating the real value of the controllable part of the profit; this penalty, if any failure occurs, should be removed from the objective function. The removal can be carried out by a post-processing of the model results. In this research the results are exported to Excel spreadsheets and the removal is carried out by a simple Microsoft Visual Basic code. The code identifies the incidents where the safety stock level is breached and calculates and removes the relative penalties from the objective function.

The safety stock volume in the formulation is shown by MI_2 and the penalty for a fall in this level for each cubic-meter of LNG is CS. The penalty is defined to be so high that it does not permit the spot sale of safety stock volume, because, given the penalty, such a sale would not be profitable. Yet under critical conditions when there is a failure in the Trains accepting this cost for fulfilling the defined LTC demands is inevitable. The penalty of a fall in the safety stock level for each day is $max(0, MI_2 - I_h)\ CS$. I_h is the volume of LNG in the tank-farm at the end of day h. The max function helps in avoiding a negative amount – when the volume of the LNG in the tank-farm is more than the safety stock level – for the penalty, which would be meaningless. Considering this penalty for all the days of a period and the time value of money, this cost in the formulation is written as $\sum_h \frac{max(0, MI_2 - I_h)\ CS}{J(0)}$. It should be mentioned that if the change in LTC demand and the resulting deliveries for the LTC buyers in operation (discussed in Section 4.1 as one of the reasons for operational planning) causes the producer to cut into the safety stock volume in normal circumstances in order to respond to the new demand; logically such an amendment in demand should be refused as serving the LTC demands under normal circumstances with the safety stock volume is not the purpose of this stock.

4.4.1.3. Revenue of uncommitted product (spot) sale

There is revenue in selling uncommitted LNG as defined in the previous section. A spot sale of uncommitted product carried out by tanker t, leaving the LNG production plant on day h for uncommitted product destination d is shown in the formulation by X_{htd}. If such a sale occurs then for each tonne of uncommitted LNG a positive cash flow is received by the producer.

For a sale of uncommitted product with tanker t, the tonnage of LNG sold is determined as $CA_t\ DE\ X_{htd}$, where CA_t is the capacity of the tanker in cubic-meters and DE is the density of LNG in tonnes/cubic-meters. The spot price for LNG, which is the price on the day (h) that the uncommitted product cargo is dispatched to uncommitted product destination d in the formulation is shown as SP_{hd}; in this work like the works of Rakke et al. (2011) and Halvorsen-Weare and Fagerholt (2013) the prices are defined for each tonne of LNG. It was discussed in Section 4.3 that this cash flow is received upon delivery of the uncommitted product cargo hence, is discounted as $J(H1_{td})$. $H1_{td}$ is the travelling time/outgoing leg between the LNG production plant and the uncommitted product destination d by tanker t. Hence, the revenue in selling such a cargo would be $\frac{SP_{hd}\ CA_t\ DE\ X_{htd}}{J(H1_{td})}$. Considering all the days of the period, for all the tankers and for all the uncommitted product destinations the revenue of such sales would be $\sum_h \sum_t \sum_d \frac{SP_{hd}\ CA_t\ DE\ X_{htd}}{J(H1_{td})}$.

4.4.1.4. Revenue of (spot sale in) arbitrage

According to Section 4.3 there are two cash flows in determining an arbitrage revenue for a producer, the extra income as the result of arbitrage and the cost of arbitraged LNG replacement for the CIF/DES-LTC buyer, if relevant.

Extra income in arbitrage: the extra income of the LNG producer in arbitraging a tonne of a CIF/DES-LTC delivery, because of a traditional LTC or self-contract, from CIF/DES-LTC destination d to arbitrage destination v dispatching it on day h by an arbitrage type s in the formulation is shown as DI_{hdvs}. The decision on an arbitrage delivery in the formulation is shown by Z_{htdvs}, if tanker t is assigned for such a delivery the total tonnage of the arbitraged LNG would be $CA_t\ DE\ Z_{htdvs}$, hence, the total extra income in this arbitrage would be $DI_{hdvs}\ CA_t\ DE\ Z_{htdvs}$. Considering the time value of money and the fact that the extra income is received upon delivery of the cargo, the extra revenue in arbitrage is discounted as $\frac{DI_{hdvs}\ CA_t\ DE\ Z_{htdvs}}{J(H1_{tv})}$. $H1_{tv}$ is the travelling time/outgoing leg for tanker *t* from the LNG production plant to arbitrage destination v. Considering all the days of the period, for all the tankers, for all the CIF/DES-LTC destinations, for all the arbitrage destinations and both arbitrage types the arbitrage extra income would be $\sum_h \sum_t \sum_{d=1}^{CD} \sum_v \sum_s \frac{DI_{hdvs}\ CA_t\ DE\ Z_{htdvs}}{J(H1_{tv})}$.

Cost of arbitraged LNG replacement: the amount of LNG that a CIF/DES-LTC buyer is supposed to receive at his respective destination d on day h by the fleet of the LNG producer – this is his CIF/DES-LTC demand/delivery – in the formulation is shown as DD_{hd}. Given the circumstances the buyer may want to, or agree to, arbitrage part or whole of the DD_{hd}. If, given the type of arbitrage, there is a need to replace the arbitraged LNG, it is assumed that the CIF/DES-LTC buyer would want to receive the replacement on the day that the initial LNG delivery was supposed to be received by him, this day being h. This is a logical assumption if the CIF/DES-LTC buyer needs his delivery and accepts the LNG arbitrage subject to its replacement, he has planned his activities according to the predetermined date for the delivery of which part or all has now been arbitraged. Given this, he would want to receive the replacement on the day that the arbitraged LNG was supposed to be received.

The cost of replacement of one tonne of LNG because of an arbitrage type s from gas markets for CIF/DES-LTC destination d received in that destination on day h in the formulation is shown by UP_{hds}. If there is no need for cargo replacement (s = 2) then UP_{hds} would be zero.

The tonnage of arbitraged LNG by a tanker is equal to $CA_t \; DE \; Z_{(h-H1_{td})tdvs}$; the cost of replacement of that cargo is equal to $UP_{hds} \; CA_t \; DE \; Z_{(h-H1_{td})tdvs}$. It is important to note that the arbitraged cargo carried by tanker t leaves the LNG production plant $H1_{td}$ sooner; this means this cargo could be delivered to the CIF/DES-LTC destination d on day h to fulfil DD_{hd} but instead it is redirected for the purpose of arbitrage to arbitrage destination *v,* and because of this arbitrage there is a need for a cargo replacement to be received on day h in CIF/DES-LTC destination d. Considering the time value of money and the assumption that the replacement is paid for by the LNG producer upon receipt at the CIF/DES-LTC destination d the cost of cargo replacement is written as $\frac{UP_{hds} \; CA_t \; DE \; Z_{(h-H1_{td})tdvs}}{J(0)}$.

Considering all the days, all the tankers, all the CIF/DES-LTC destinations, all the arbitrage destinations and all the arbitrage types, the cost of the arbitraged cargo replacement would be $\sum_h \sum_t \sum_{d=1}^{CD} \sum_v \sum_s \frac{UP_{hds} \; CA_t \; DE \; Z_{(h-H1_{td})tdvs}}{J(0)}$.

All the components of the objective function have been derived and it is now possible to combine them and form the entire function. In combining the components of the objective function for maximizing the controllable part of the profit, the revenues in uncommitted product sales and arbitrage are multiplied by a negative then added to the costs. The sum of the costs and the negative revenues should be minimized for maximization of the controllable part of the profit. The objective function and its components are equation number (2), numbers on the equation i.e. (i), (ii), (iii) and (iv) refer to different parts of the objective function previously discussed.

$$
\begin{aligned}
Min \sum_{h} \Bigg\{ & \underbrace{\sum_{t=1}^{FT}\sum_{d}\sum_{f}\frac{CT_{htdf}\,X_{htd}}{J(RT_{tdf})} + \sum_{t=1}^{FT}\sum_{d=1}^{CD}\sum_{f}\frac{CT_{htdf}\,Y_{htd}}{J(RT_{tdf})} + \sum_{t=1}^{FT}\sum_{d=1}^{CD}\sum_{v}\sum_{s}\sum_{f}\frac{CT_{htvf}\,Z_{htdvs}}{J(RT_{tvf})}}_{\text{cost of fixed tankers (i)}} \\
& + \underbrace{\sum_{t=FT+1}^{PT}\sum_{d}\frac{SC_{htd}\,X_{htd}}{J(0)} + \sum_{t=FT+1}^{PT}\sum_{d=1}^{CD}\frac{SC_{htd}\,Y_{htd}}{J(0)} + \sum_{t=FT+1}^{PT}\sum_{d=1}^{CD}\sum_{v}\sum_{s}\frac{SC_{htv}\,Z_{htdvs}}{J(0)}}_{\text{cost of spot tankers (i)}} \\
& - \underbrace{\sum_{t}\sum_{d}\frac{SP_{hd}\,CA_t\,DE\,X_{htd}}{J(H1_{td})}}_{\text{Revenue of uncommitted product sales (iii)}} \\
& - \underbrace{\sum_{t}\sum_{d=1}^{CD}\sum_{v}\sum_{s}\frac{DI_{hdvs}\,CA_t\,DE\,Z_{htdvs}}{J(H1_{tv})}}_{\text{Extra income in arbitrage of CIF/DES-LTC cargos (iv)}} \\
& + \underbrace{\sum_{t}\sum_{d=1}^{CD}\sum_{v}\sum_{s}\frac{UP_{hds}\,CA_t\,DE\,Z_{(h-H1_{td})tdvs}}{J(0)}}_{\text{cost of cargo replacement in arbitrage (iv)}} \\
& + \frac{\underbrace{IC_h\,I_h}_{\text{operational cost of tank-farm (ii)}} + \underbrace{max(0, MI_2 - I_h)\,CS}_{\text{penalty of fall in safety stock level of tank-farm (ii)}}}{\underbrace{J(0)}_{\text{a typical discounting factor}}} \Bigg\}
\end{aligned}
\qquad (2)
$$

The constraints follow the objective function.

4.4.2. Inventory constraints

This set of constraints includes two equations; the inventory balance (4.4.2.1) and inventory limits constraints (4.4.2.2).

4.4.2.1. Inventory balance constraint

In this constraint the incoming and outgoing LNG each day is tracked and, as a result, the volume – in cubic-meters – of the remaining LNG in the tank-farm at the end of each day is determined. The incoming and outgoing LNG consists of three parts; the daily production of LNG in the liquefaction plant, the dispatched LNG for CIF/DES-LTC, arbitrage and uncommitted product deliveries, and the LNG that is delivered to the LTC buyers in the production plant, i.e. FOB deliveries (in traditional LTCs). In addition to the aforementioned flows of LNG, there is an inventory balance of LNG that is carried forward from yesterday. This LNG remaining in the tank-farm from yesterday needs to be taken into account.

The daily production of LNG: there is a daily flow of LNG into the tank-farm from the liquefaction Trains (see Figure 4.1). This daily incoming flow from the Trains of the LNG liquefaction plant in the LNG sector is quoted in tonnes. In the formulation, LNG in the LNG plant, on day h, entering the tank-farm is shown as PP_h. This factor needs to be converted from tonnes to cubic-meters to be considered in the calculations; this is done by $\frac{PP_h}{DE}$, where DE is the density of LNG.

Dispatched LNG for CIF/DES-LTC, arbitrage and uncommitted product deliveries: on each day a number of cargos are dispatched by the LNG producer's fleet for the purpose of arbitrage, CIF/DES-LTC deliveries or uncommitted product sales. Considering all the tankers and uncommitted product destinations the total volume – in cubic-meters – of dispatched uncommitted LNG on day h can be calculated as $\sum_t \sum_d CA_t\, X_{htd}$. In the same way as for uncommitted product sales, the CIF/DES-LTC and arbitrage volumes leaving the tank-farm on day h are $\sum_t \sum_t \sum_{d=1}^{CD} CA_t\, Y_{htd}$ and $\sum_t \sum_{d=1}^{CD} \sum_v \sum_s CA_t\, Z_{htdvs}$, respectively.

FOB deliveries related to traditional LTCs in the production plant: as discussed in Section 4.2, some traditional LTC holders have FOB contracts, hence, they send their own tankers to take the LNG from the production plant. The tonnage of FOB-LNG leaving the plant on each day is pre-determined. This factor, shown in the formulation by DP_h, in the inventory balance constraint is considered as $\frac{DP_h}{DE}$.

The LNG balance from yesterday: there is an LNG balance – in cubic-meters – in the tank-farm that is carried forward from yesterday; this is shown as I_{h-1}. At the beginning of the period there is no LNG brought forward from yesterday; in this case I_{h-1} should be replaced by IB. IB is the volume of LNG in the tank-farm at the beginning of period.

Compiling all the positive/incoming and negative/outgoing LNG flows, plus considering the balance of yesterday, the volume of LNG – in cubic-meters – in the tank-farm at the end of day h, shown in the formulation as I_h, is calculated by equation number (3):

$$I_h = \underbrace{I_{h-1}}_{\text{the LNG balance from yesterday}} + \overbrace{\left(\frac{PP_h}{DE}\right)}^{\text{the daily production of LNG}} - \overbrace{\sum_t \sum_d CA_t\, X_{htd} - \sum_t \sum_{d=1}^{CD} CA_t\, Y_{htd} - \sum_t \sum_{d=1}^{CD} \sum_v \sum_s CA_t\, Z_{htdvs}}^{\text{dispatched LNG for CIF/DES-LTC, arbitrage and uncommitted product deliveries}} - \underbrace{\left(\frac{DP_h}{DE}\right)}_{\text{FOB deliveries at the LNG production plant}} \quad \forall h \qquad (3)$$

4.4.2.2. Inventory limits constraint

There is a limit to the total volume of LNG that can be kept in the tank-farm, this is the capacity of the tank-farm – in cubic-meters – and in the formulation it is shown as MI_3. There is also a limit to the lowest possible volume of LNG in the tanks of the tank-farm. In the LNG industry the tanks of the tank-farm cannot be totally emptied since, if that occurs, then they start to become warm. Cooling a warm tank back to -160 degrees Celsius, which is the correct temperature for storing LNG, is costly and time consuming; to avoid this a little volume of LNG should always be left in each tank. This is usually 0.5 - 2% of the capacity of a tank (Flower, 2010). The sum of minimum acceptable volumes of

LNG in the tanks of a tank-farm in this formulation is shown as MI_1[1]. MI_1 should not be mistaken for the safety stock volume MI_2 used in developing the objective function; $MI_1 < MI_2$.

The volume of LNG remaining in the tank-farm at the end of each day (h) should lie between the maximum and minimum possible volumes of LNG in the tank-farm, this is provided in the formulation by equation number (4):

$$\underset{\text{minimum possible volume in the tank-farm}}{MI_1} \leq \overset{\text{Volume of LNG in the tank-farm}}{I_h} \leq \underset{\text{capacity of the tank-farm}}{MI_3} \qquad \forall\, h \tag{4}$$

4.4.3. CIF/DES-LTC demands/deliveries (DD_{hd}) fulfilment constraint

It was discussed that LTC demands consist of two groups; demands with FOB and CIF/DES deliveries. Of these two LTC demands, FOB deliveries defined for traditional LTCs are taken by the fleet of the FOB-LTC buyer. These buyers inform the LNG producer of the time they are going to send their tankers for off-taking the product.

However, execution of CIF/DES-LTC deliveries for self-contracts and traditional LTCs needs to be planned by the LNG producer, the producer should assign tankers to carry out the deliveries and satisfy the demands of CIF/DES-LTC buyers. If there is a delivery on day h for CIF/DES-LTC destination d (DD_{hd}) then considering all the tankers of the LNG producer that delivery is carried out as $\sum_t CA_t\, Y_{(h-H1_{td})td}$. If a delivery should be

[1] The same as tanks of the tank-farm, tanks of a tanker can become warm, hence, there should be remain a little volume of LNG in these tanks too. CA_t, the capacity of LNG tankers in the problem, is defined excluding this volume.

carried out by a particular tanker or a set of tankers the decision-variable Y_{htd} should be defined explicitly equal to one for those deliveries for the problem.

In developing the objective function it was seen that the amount of transported LNG to CIF/DES-LTC destination d in fulfilling DD_{hd} is not always equal to DD_{hd} and, on such an occasion the difference is arbitraged. The possibility of under delivery in response to DD_{hd} in the formulation is provided by a factor named LV_{hd}. The party that suggests the arbitrage might be the producer, the CIF/DES-LTC buyer or any other party (2.4.3). Regardless of the party that suggests the arbitrage, LV_{hd} represents the proportion of DD_{hd} that the CIF/DES-LTC buyer is ready to arbitrage.

Given the discussion of the last paragraph, the maximum volume – in cubic-meters – of CIF/DES-LTC delivery of LNG on day h to CIF/DES-LTC destination d is $\frac{DD_{hd}}{DE}$, and the minimum acceptable CIF/DES-LTC delivery to the CIF/DES-LTC buyer is $\frac{DD_{hd}}{DE}\left(1-\frac{LV_{hd}}{100}\right)$; $\frac{DD_{hd}\,LV_{hd}}{100\,DE}$ can potentially be arbitraged. To make a decision on the opportunity of an arbitrage the producer would need to consider the size of his extra income, the cost of replacement for the arbitraged cargo if relevant, the cost of transport in arbitrage (all taken to account in the objective function), and the logistical possibility of doing the arbitrage (which is taken to account in the tanker availability constraints – discussed later), before making a decision. Considering the upper and lower limits in fulfilling DD_{hd} and the tanker assignment in response to such a demand, equation number (5) is derived:

$$\overbrace{\boxed{\frac{DD_{hd}}{DE}\left(1-\frac{LV_{hd}}{100}\right)}}^{\text{minimum acceptable CIF/DES-LTC delivery}} \leq \underbrace{\boxed{\sum_{t} CA_t\, Y_{(h-H1_{td})td}}}_{\text{CIF/DES-LTC delivery by the LNG producer's fleet}} \leq \overbrace{\boxed{\frac{DD_{hd}}{DE}}}^{\text{maximum possible CIF/DES-LTC delivery}}, \quad if\ DD_{hd} > 0 \quad \forall\, h, d \in \{1, \dots, CD\} \qquad (5)$$

4.4.4. Arbitrage constraints

This set of constraints is composed of two equations; the arbitraged product delivery constraint (4.4.4.1) and the arbitrage type constraint (4.4.4.2).

4.4.4.1. The arbitraged product delivery constraint

From the previous constraint there is a possibility for a portion of DD_{hd} to be arbitraged. If the producer believes the arbitrage is beneficial, given its costs and benefits, then he would need to deliver the arbitraged LNG by assigning some tankers.

The volume of arbitraged LNG, subject to having a DD_{hd} on day h for CIF/DES-LTC destination d, is the difference between DD_{hd} and the total volume of the CIF/DES-LTC delivery that actually was carried out in response to that demand. This volume – in cubic-meters – is equal to $\frac{DD_{hd}}{DE} - \sum_t CA_t\, Y_{(h-H1_{td})td}$.

If an arbitrage is carried out (Z_{htdvs} = 1) the volume of arbitraged LNG is equal to the capacity of the tanker assigned for that arbitrage, this volume in cubic-meters is $CA_t\, Z_{htdvs}$. Considering all the tankers, all the possible arbitrage destinations and all the possible types of arbitrage, the total volume of arbitraged LNG, carried out by the LNG producer's fleet, from CIF/DES-LTC destination d that was supposed to be delivered to this destination on day h is equal to $\sum_t \sum_v \sum_s CA_t\, Z_{(h-H1_{td})tdvs}$. Given the discussions of 4.4.4.1 there is equation number (6):

$$\underbrace{\overbrace{\frac{DD_{hd}}{DE}}^{\text{CIF/DES-LTC demand}} - \overbrace{\sum_t CA_t\, Y_{(h-H1_{td})td}}^{\text{the volume of CIF/DES-LTC delivery}}}_{\text{the volume of arbitraged LNG}} = \underbrace{\sum_t \sum_v \sum_s CA_t\, Z_{(h-H1_{td})tdvs}}_{\text{the volume of arbitraged LNG by the LNG producer's fleet}}, \quad if\ DD_{hd} > 0 \quad \forall\, h,d \in \{1, \dots, CD\} \tag{6}$$

4.4.4.2. Arbitrage type constraint

There are two types of arbitrage in the formulation: with cargo replacement (s = 1) and without cargo replacement (s = 2). The CIF/DES-LTC buyer (defined for the project because of a self-contract or a traditional LTC) needs to let the LNG producer know that in case a portion of his DD_{hd} is arbitraged whether he wants a replacement or not (It is assumed if a portion of DD_{hd} is arbitraged, the whole arbitraged volume is with or without replacement). If there is a need for replacement then related to DD_{hd} there cannot be any arbitrage for which there is no replacement. In other words $\sum_t \sum_v \sum_{s=2} CA_t\, Z_{(h-H1_{td})tdvs} = 0$ and if there is no need for replacement, then, $\sum_t \sum_v \sum_{s=1} CA_t\, Z_{(h-H1_{td})tdvs} = 0$.

there can not be any arbitrage delivery with replacement if the CIF/DES-LTC buyer has not asked for any replacement

$$\left.\begin{array}{c}\boxed{\sum_{t}\sum_{v}\sum_{s=1} CA_t\, Z_{(h-H1_{td})tdvs} = 0}\\ or \\ \sum_{t}\sum_{v}\sum_{s=2} CA_t\, Z_{(h-H1_{td})tdvs} = 0\end{array}\right\} \quad if\ DD_{hd} > 0 \quad \forall\, h,d$$

$$\in \{1, \dots, CD\} \qquad (7)$$

4.4.5. Berthing service constraints

This set of constraints consists of two equations: berth capacity control (4.4.5.1) and berth availability in the production plant (4.4.5.2).

4.4.5.1. Berth capacity control

A point that needs to be taken into account when a spot or fixed tanker is assigned for a delivery is the possibility of servicing that tanker at the production and destination terminals. In other words, the size of the berths in the production and destination terminals should permit a tanker to load and unload LNG at these terminals, respectively. In the LNG sector the tankers and berths are classified according to their capacity in cubic-meters.

Imagine that a CIF/DES-LTC delivery is carried out by tanker t to CIF/DES-LTC destination d ($Y_{htd} = 1$). The capacity of the tanker that is doing the delivery in cubic-meters is $CA_t\, Y_{htd}$. If the capacities of the berths at the production and destination terminals are, respectively, MT_0 and MT_d in cubic-meters, then the capacity of the assigned tanker for service between these terminals should be smaller than or equal to $min\{MT_0, MT_d\}$. This means this that tanker is serviceable at both terminals. The LNG production plants and regas terminals have a very limited number of berths. The berths, if more than one, in many cases have the same capacity. These berths are capable of servicing a wide range of tankers and they are bounded by the biggest tanker they can service. This control needs to be carried out for all the tankers leaving the LNG production plant and to every CIF/DES-LTC, arbitrage or uncommitted product destinations. Berth capacity control is carried out by equation number (8):

$$\left.\begin{array}{ll} \overbrace{\boxed{CA_t\, Y_{htd}}}^{\text{capacity of the tanker on a CIF/DES-LTC delivery}} \leq \overbrace{\boxed{min\,\{\, MT_0, MT_d \,\}}}^{\text{capacity of the smaller berth between the LNG production plant and the CIF/DES-LTC destination}} & \forall\, h,t,d \in \{1,\dots,CD\} \\ CA_t\, X_{htd} \leq min\,\{\, MT_0, MT_d \,\} & \forall\, h,t,d \\ CA_t\, Z_{htdvs} \leq min\,\{\, MT_0, MT_v \,\} & \forall\, h,t,d \in \{1,\dots,CD\}, v, s \end{array}\right\} \qquad (8)$$

4.4.5.2. Berth availability in the production plant

There are a specific number of berths available in the LNG production plant, the number of these berths in the formulation is specified as NB. Each day, a number of tankers are loaded at the production plant for arbitrage, uncommitted product, CIF/DES-LTC and FOB-LTC deliveries. The total number of these tankers, the loading of each is assumed to take one day, cannot be more than the number of berths at the production plant.

The total number of loaded tankers for uncommitted product, arbitrage and CIF/DES-LTC deliveries on each day is $\sum_t \sum_d X_{htd} + \sum_t \sum_{d=1}^{CD} Y_{htd} + \sum_t \sum_{d=1}^{CD} \sum_v \sum_s Z_{htdvs}$. The number of tankers arriving for off-taking the FOB-LTC cargos each day is pre-determined in the ADP, and any change in them, which is associated with a change in the LTC demand/delivery of the FOB buyer, is decided in advance. This number in the formulation is defined as NP_h. Considering all the tankers which are serviced and the total number of berths, equation number (9) is derived:

assigned tankers for arbitrage, uncommitted product and CIF/DES-LTC deliveries

arrived tankers for taking the FOB-LTC deliveries

$$\boxed{\sum_{t}\sum_{d} X_{htd} + \sum_{t}\sum_{d=1}^{CD} Y_{htd} + \sum_{t}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{htdvs}} + NP_h \leq NB \quad \forall\, h \qquad (9)$$

number of berths in the LNG production plant

4.4.6. Tanker assignment constraints

This set of constraints includes three equations: spot chartered tanker service constraint (4.4.6.1), fixed tanker service constraint (4.4.6.2), constraint for tanker unavailability due to being late, unfinished with an assignment or out-of-service (4.4.6.3).

4.4.6.1. Spot chartered tanker service constraint

If a tanker is spot chartered, it essentially can be used for transporting one and only one uncommitted product, arbitrage or CIF/DES-LTC cargo. The fact that this tanker can serve the LNG producer for one trip should be considered in the formulation.

Imagine that tanker t on day h is spot chartered for an uncommitted product delivery to uncommitted product destination d (X_{htd} = 1), this tanker when dispatched cannot be assigned to any other uncommitted product delivery for the rest of the days of the period. This means this tanker is crossed off the list of available tankers that can be spot chartered – defined under index t as FT+1, ..., PT – for the rest of the period[1]. The days

[1] There is no guarantee that the spot tanker, after delivering its cargo, will return to the production terminal's region or even if it returns would be available for spot chartering. But if the tanker returns and it is available, its availability – as new information – can be considered in planning the next period in the rolling horizon process (4.4.8).

of a period begin with 1 and end with *PH*. There is no need to mention that there are tankers in the list of available vessels for spot chartering that are not spot chartered in the period, for these tankers (X_{htd} = 0) through the period. This discussion can be translated into an equation as $\sum_{a=0}^{PH-h}\sum_d X_{(h+a)td} \leq 1$.

Looking at the bigger picture, a spot chartered tanker can be used for one arbitrage, uncommitted product or CIF/DES-LTC delivery. This means, for example, if on day h for tanker t there is X_{htd} = 1 then for the rest of the days of the period Z_{htdvs} = Y_{htd} = 0. Having said this, the equation suggested at the end of the last paragraph can be expanded as equation number (10):

possible assignment of an available tanker for spot chartering to uncommitted product, arbitrage or CIF/DES-LTC delivery

a tanker available for spot chartering can be used for one and only one delivery if chartered

$$\sum_{a=0}^{PH-h}\sum_{d} X_{(h+a)td} + \sum_{a=0}^{PH-h}\sum_{d=1}^{CD} Y_{(h+a)td} + \sum_{a=0}^{PH-h}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{(h+a)tdvs} \leq 1 \qquad \forall\, h,t \in \{FT+1,\dots,FT+ST\} \qquad (10)$$

4.4.6.2. Fixed tankers service constraint

If a fixed tanker is assigned by the LNG producer to a delivery, then that tanker on the assignment day can be dispatched to do only one of the possible types of delivery, including uncommitted product (X_{htd}), arbitrage (Z_{htdvs}) and CIF/DES-LTC (Y_{htd}). In other words, one of the aforementioned decision-variables can be equal to one on that day. Therefore for fixed tanker t on day h the following should stand $\sum_d X_{htd} + \sum_{d=1}^{CD} Y_{htd} + \sum_{d=1}^{CD}\sum_v\sum_s Z_{htdvs} \leq 1$.

Another important point in using fixed tankers is that when a fixed tanker is dispatched to do a delivery, then that tanker cannot be assigned to do any other delivery, including uncommitted product, arbitrage and CIF/DES-LTC until it is finished with its current assignment. Imagine that fixed tanker t on day h is assigned to do an uncommitted product delivery (X_{htd} = 1) to uncommitted product destination $d;$ for this tanker, except for the aforementioned decision-variable, which is equal to one, the rest of the tanker assignment decision-variables, including X_{htd} and Y_{htd} and Z_{htdvs}, should be equal to zero until it finishes its current assignment. The time that it takes for tanker t to do an uncommitted product delivery to uncommitted product destination d and return to the LNG production plant in the formulation is specified as HH_{td}. Therefore, for tanker t there is $\sum_{a=0}^{HH_{td}-1}\sum_{d} X_{(h+a)td} + \sum_{a=0}^{HH_{td}-1}\sum_{d=1}^{CD} Y_{(h+a)td} + \sum_{a=0}^{HH_{td}-1}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{(h+a)tdvs} = 1.$

But if fixed tanker t is not dispatched for an uncommitted product delivery today it can be dispatched for a uncommitted product, arbitrage or CIF/DES-LTC delivery at any time that it was supposed not to be available before i.e. any of HH_{td} days ahead. Combining the discussions of this paragraph and the previous one results in the following equation;

$2\,PD\,HH_{trd}\,(PV+\ 1)\,X_{htrd} + \sum_{a=0}^{HH_{td}-1}\sum_{d} X_{(h+a)td} + \sum_{a=0}^{HH_{td}-1}\sum_{d=1}^{CD} Y_{(h+a)td} +$

$\sum_{a=0}^{HH_{td}-1}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{(h+a)tdvs} \leq 2\,PD\,HH_{td}\,(PV+\ 1) + 1.$

All the checks and controls of the last two paragraphs were for the assignment of a fixed tanker to an uncommitted product delivery; the same controls and checks need to be carried out for a fixed tanker's assignment to arbitrage and CIF/DES-LTC deliveries too. In summation, for a fixed tanker there is equation number (11):

$$\left.\begin{aligned}
&(*)\ \overbrace{2\,PD\,HH_{trd}\,(PV+\ 1)\,X_{htrd}}^{\text{part 1}} + \overbrace{\sum_{a=0}^{HH_{td}-1}\sum_{d} X_{(h+a)td} + \sum_{a=0}^{HH_{td}-1}\sum_{d=1}^{CD} Y_{(h+a)td}}^{\text{Part 2}} \\
&+ \sum_{a=0}^{HH_{td}-1}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{(h+a)tdvs} \le \underbrace{2\,PD\,HH_{td}\,(PV+\ 1)+1}_{\text{Part 3}} \qquad \forall h,t \in \{1,\dots,FT\}, d \\
&(*)\ 2\,PD\,HH_{trd}\,(PV+\ 1)\,Y_{htrd} + \sum_{a=0}^{HH_{td}-1}\sum_{d} X_{(h+a)td} + \sum_{a=0}^{HH_{td}-1}\sum_{d=1}^{CD} Y_{(h+a)td} \\
&+ \sum_{a=0}^{HH_{td}-1}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{(h+a)tdvs} \le 2\,PD\,HH_{td}\,(PV+\ 1)+1 \qquad \forall h,t \in \{1,\dots,FT\}, d \in \{1,\dots,CD\} \\
&(*)\ 2\,PD\,HH_{trv}\,(PV+\ 1) Z_{htdvs} + \sum_{a=0}^{HH_{tv}-1}\sum_{d} X_{(h+a)td} + \sum_{a=0}^{HH_{tv}-1}\sum_{d=1}^{CD} Y_{(h+a)td} \\
&+ \sum_{a=0}^{HH_{trv}-1}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{(h+a)tdvs} \le 2\,PD\,HH_{trv}\,(PV+\ 1)+1 \qquad \forall h,t \in \{1,\dots,FT\}, d \in \{1,\dots,CD\}, v, s \\
&\sum_{d} X_{htd} + \sum_{d=1}^{CD} Y_{htd} + \sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{htdvs} \le 1 \qquad \forall h,t \in \{1,\dots,FT\}
\end{aligned}\right\}\ (11)$$

There is a great deal of similarity among the mathematical phrases marked with star (*) in equation (11), these similarities – shown on the first star phrase as parts 1, 2 and 3 – can be used to simplify and shorten this equation.

Looking at part 1, it is seen that, for this part, among the three starred phrases the differences are the duration of the trip – in the first two starred phrases this duration is HH_{td} while in the third phrase it is HH_{td} – and the decision-variable X_{htd}, Y_{htd} and Z_{htdvs}, respectively. Given these differences, part 1 can be written as a function $F(x, y) = 2\,PD\,x\,(PV+\ 1)\,y$, where x and y are variables of this function which, for example, for the first starred phrase are defined as $x = HH_{td}$ and $y = X_{htd}$.

In the same way as for part 1, for parts 2 and 3 a function is defined to shorten equation (11). For part 2 the function is $G(y-1) = \sum_{a=0}^{y-1}\sum_{d} X_{(h+a)td} + \sum_{a=0}^{y-1}\sum_{d=1}^{CD} Y_{(h+a)td} + \sum_{a=0}^{y-1}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{(h+a)tdvs}$ and for part 3 it is $H(y) = 2\,PD\,y\,(PV+\ 1) + 1$. Considering the functions, equation (11) is re-written as:

A fixed tanker is not assigned to any other delivery until it is back from its current assignment

$$\left.\begin{array}{l} \boxed{F(x,y)+G(y-1)\le H(y)} \\ where: \\ \left.\begin{array}{llll} x=HH_{td} & and & y=X_{htd}\,, & \forall\, h,t\in\{1,\dots,FT\},d \\ x=HH_{td} & and & y=Y_{htd}\,, & \forall\, h,t\in\{1,\dots,FT\},d\in\{1,\dots,CD\} \\ x=HH_{tv} & and & y=Z_{htdvs}\,, & \forall\, h,t\in\{1,\dots,FT\},d\in\{1,\dots,CD\},v,s \end{array}\right\} \\ \boxed{\sum_{d} X_{htd}+\sum_{d=1}^{CD} Y_{htd}+\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{htdvs}\le 1} \quad \forall\, h,t\in\{1,\dots,FT\} \end{array}\right\} \qquad (11)$$

A fixed tanker can be dispatched for only one type of delivery on every day

4.4.6.3. Constraint for tanker unavailability due to being late, out-of service or unfinished with an assignment

In equations (10) and (11) service constraints for spot and fixed tankers are defined. In equation (11) the assignment of fixed tankers to deliveries is characterized and it is clarified that while these tankers are away on service they cannot do any other delivery. But there are days during an LNG project that a fixed tanker cannot be used not because it is away on a planned delivery with a predefined duration, rather due to dry-docking, a technical problem or simply because the tanker is returning late due to bad weather – the trip time duration is more than the predefined duration. Apart from these, there is a chance that a fixed tanker is not available from the beginning of the period planned due to being on another assignment which is not finished until the beginning of the period studied. All of these days need to be marked and defined separately in the formulation and considered in planning the period.

With regards to spot tankers, equation (10) implies that a spot chartered tanker can be assigned to only one delivery by the producer. To spot charter a tanker the producer chooses a tanker from the list of available tankers for spot chartering. But there might be a tanker in the list that is not available from the first day of the period planned, but becomes available 10 days after the beginning of the period. The unavailability of this potential spot tanker that is not covered by equation (10) needs to be taken into account.

To consider the days a fixed or a potential spot tanker is not available due to the reasons discussed in the last two paragraphs a parameter named UT_{ht} is defined in the formulation; this factor is one by default unless chosen to be zero. Imagine that tanker t is not available for delivering any uncommitted product, arbitrage or CIF/DES-LTC cargo on day h due to the aforementioned issues, then to take this into account UT_{ht} is chosen equal to zero on day h for tanker t; therefore $\sum_{d=1}^{CD} Y_{htd} = \sum_d X_{htd} = \sum_{d=1}^{CD} \sum_v \sum_s Z_{htdvs} = UT_{ht} = 0$.

If a tanker is not late, out-of service or unfinished with a previous assignment (UT_{ht} = 1) then it can be assigned to do a delivery. This means the defined variables for assigning tankers to uncommitted product (X_{htd}), arbitrage (Z_{htdvs}) or CIF/DES-LTC (Y_{htd}) deliveries can be either one/assigned or zero/not assigned. In summation, the unavailability of tankers due to being late, unfinished with an assignment or out-of-service is defined as equation number (12):

checking the availability of a tanker for CIF/DES-LTC deliveries

defining factor for unavailability due to being late, off-service or being unfinished with an assignment

$$\left.\begin{array}{l} \sum_{d=1}^{CD} \{Y_{htd} \leq \boxed{UT_{ht}}\} \\ \sum_{d} \{X_{htd} \leq UT_{ht}\} \\ \sum_{d=1}^{CD} \sum_{v} \sum_{s} \{Z_{htdvs} \leq UT_{ht}\} \end{array}\right\} \quad \forall\, h, t \qquad (12)$$

4.4.7. Binary constraints

An uncommitted product delivery (X_{htd}) on day h to uncommitted product destination d by tanker t is either carried out ($X_{htd} = 1$) or not carried out ($X_{htd} = 0$). The same stands for arbitrage (Z_{htdvs}) and CIF/DES-LTC (Y_{htd}) deliveries, and it is stated in the beginning of 4.4 that these are binary variables. These variables are defined in the formulation by equation number (13):

defining the binary variable for uncommitted
product-spot sale deliveries

$$\left.\begin{array}{ll} \boxed{X_{htd} \in \{0,1\}} & \forall\, h,t,d \\ Y_{htd} \in \{0,1\} & \forall\, h,t,d \in \{1,\dots,CD\} \\ Z_{htdvs} \in \{0,1\} & \forall\, h,t,d \in \{1,\dots,CD\},v,s \end{array}\right\} \qquad (13)$$

Having presented the blocks of the model, it all combines together to form the mathematical model in Appendix I.

4.4.8. Overall problem implementation and execution

The model is programmed and solved in IBM ILOG CPLEX Optimization Studio 12.3 (code is provided in Appendix II), while data is read from and results, as stated before, are exported to Excel spreadsheets. It is interesting to note that IBM ILOG CPLEX Optimization Studio 12.3 cannot read arrays with more than two dimensions directly from Excel spreadsheets. Hence, in reading from these sheets in working with variables and parameters with higher dimensions e.g. RT_{tdf} and Z_{htdvs}, they are read as tuples, transformed to arrays, then used in calculations. The reverse process occurs in writing to spreadsheets for high dimension arrays; here the arrays are transformed to tuples then written to the spreadsheets.

It is discussed in Chapter 3 that solution algorithms are not the focus of this research since a solver is used for solving the model. But the reader might be interested to know that by looking at the help file of the solver it is understood that a branch-and-bound algorithm is the core of IBM ILOG CPLEX Studio 12.3 in solving the MIP problems. In brief, a branch-and-bound algorithm is a solution finding method for discrete optimization problems that divides the set of candidate solutions, also known as feasible solution space, into subsets and rejects the unrewarding subsets by using upper and lower estimated bounds of the problem objective function. The dividing and rejecting process and looking for the optimum solution in the remains of the feasible solution space in this algorithm continues until a solution is found that there is no better solution than that; that solution is the optimum one (Taha, 1992).

It has been previously discussed that the model is solved for a time period of two to three months. After the discussion in this section, which put different factors of the model into perspective, it can be understood why the planning period is relatively short. Factors, such as those that follow, make the far future too unpredictable for operational decision-making, hence having longer periods in that level of decision-making would not be rational. Reasons such as volatility in LNG spot prices which are important in decisions for spot sales, and the unpredictability of spot tanker chartering rates which needs to be considered in tanker assignment to uncommitted product, arbitrage and CIF/DES-LTC deliveries that are both taken to account in the objective function.

The accuracy and adoptability of operational decision-making is increasing by the rolling horizon process – Figure 4.2 – that is implemented in this type of planning in the LNG sector. In this process a period is planned but the plan is not totally executed, rather, after implementing a fraction of it, the problem planning span rolls forward (Figure 4.2) and a new period is planned. This means that of the two to three months that are planned as a period, only a portion of it is executed. It is clear that the information available for planning, such as the spot prices and tankers available for spot chartering, after rolling the problem planning span forward, would be much more accurate than the information about the same days – the overlap in Figure 4.2 – in planning the previous period.

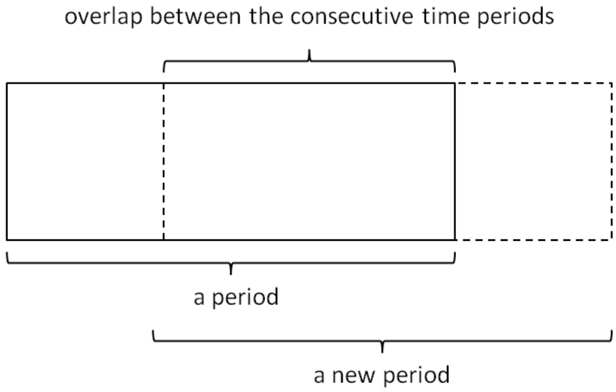


Figure 4.2 - The rolling horizon process

Usually two weeks to one month of the period planned is executed (Flower, 2011). But with unexpected/unpredictable events, such as reduction in LNG output of the Trains due to a failure, which affects the production rate of LNG PP_h in equation number (3), a technical problem with a fixed tanker, that influences equation number (12), a delay in the return of a fixed tanker from an assigned delivery due to bad weather, which concerns equation number (12), or a sharp change in spot prices in a market which may affect the LNG producer's decision on uncommitted product sales, which involves equation number (2), the rolling horizon process may need to occur earlier. These incidents if they take place after the beginning of the implementation of the period planned and during the portion of the period that is executed, may need to be taken into account. But they are not considered in the planning of the period already executed as the LNG producer did not know about them at the time. Should the LNG producer think any of these are important during the planning process, then he stops the implementation of the period planned on the day that any of these incidents occurs, considers the incident, plans a new period and executes the new plan. There is a chance that some of these incidents are not important in planning; for example, a fixed tanker that returns late and does not have a busy schedule and need not be dispatched for another delivery until after its delayed arrival, does not affect the period already planned and implemented. The LNG producer needs to consider unexpected/unpredictable incidents and decide whether they need to be taken into account or not.

Figure 4.3 puts the formulation, containing the objective function and constraints, along with the rolling horizon process, into perspective. The objective function and the set of constraints given the data read from Excel spreadsheets are built for the period studied. The set of constraints define the feasible solution space – the set of candid solutions – for the problem, and each of the constraints is essentially one of the borders of the feasible solution space. Having defined the feasible solution space the IBM ILOG CPLEX Optimization Studio 12.3 picks the best solution among the set of candidate solutions by minimizing the objective function using a branch-and-bound algorithm. The solution picked for a period includes decisions on uncommitted product (X_{htd}), arbitrage (Z_{htdvs}) and CIF/DES-LTC (Y_{htd}) deliveries along with the volume of LNG in the tank-farm at the end of each day (I_h) that are meant to minimize the objective function (maximize the revenue in uncommitted product sales and arbitrage, and minimize the tanker and tank-farm costs). After picking a solution for a specific period, in time the problem planning span rolls forward and the next period is planned by following the same procedure discussed in this paragraph.

With regards to the extent that producers can respond to changes in LTC demands it should be noted that if a negotiated change, in putting into practice by affects the constraints, results in a situation where no feasible solution space can be defined, there is no solution that satisfies all the constraints, then the problem would be infeasible. In other words, such a change would not be possible. For example, if by changing the volume of deliveries to a LTC buyer there is need for a tanker to be loaded on a specific day in the production plant while all the berths on that day are occupied by tankers that are serving compulsory deliveries, this concerns equation (9), then such a change would not be possible, and the problem would be infeasible.

It should also be noted that the set of decisions made and executed in running the system in the last period (the solution picked for the last period) may affect the feasible solution space in the next period planned. For example, if a fixed tanker is dispatched to do a delivery in the last period and it is not back for the beginning of the new period, then in reading the data from Excel spreadsheets for the new period in which decisions made in the last period are considered, this unavailability is identified and taken into account. This unavailability is considered in equation (12) for the new period hence, affecting the feasible solution space for this period. In other words, the decisions made in the last period influence and limit the choice of decisions for the new period.

4.5. Concluding remarks

In this chapter an operational model for running an LNG production and distribution project is presented. The MIP model covers all types of LNG trades including: traditional LTCs (with CIF/DES and FOB deliveries), self-contracts (with CIF/DES deliveries) and spot sales for uncommitted product and in arbitrage (of CIF/DES deliveries in self-contracts and traditional LTC). It permits usage of both fixed and spot tankers for cargo delivery. One of the interesting features of the model is consideration of the time value of money which, given the magnitude of the cash flows in the LNG business, can be important in decision-making.

Now that the model has been developed different aspects of the LNG business can be studied. This is the agenda for the next chapter where business characteristics such as arbitrage are studied and discussed.

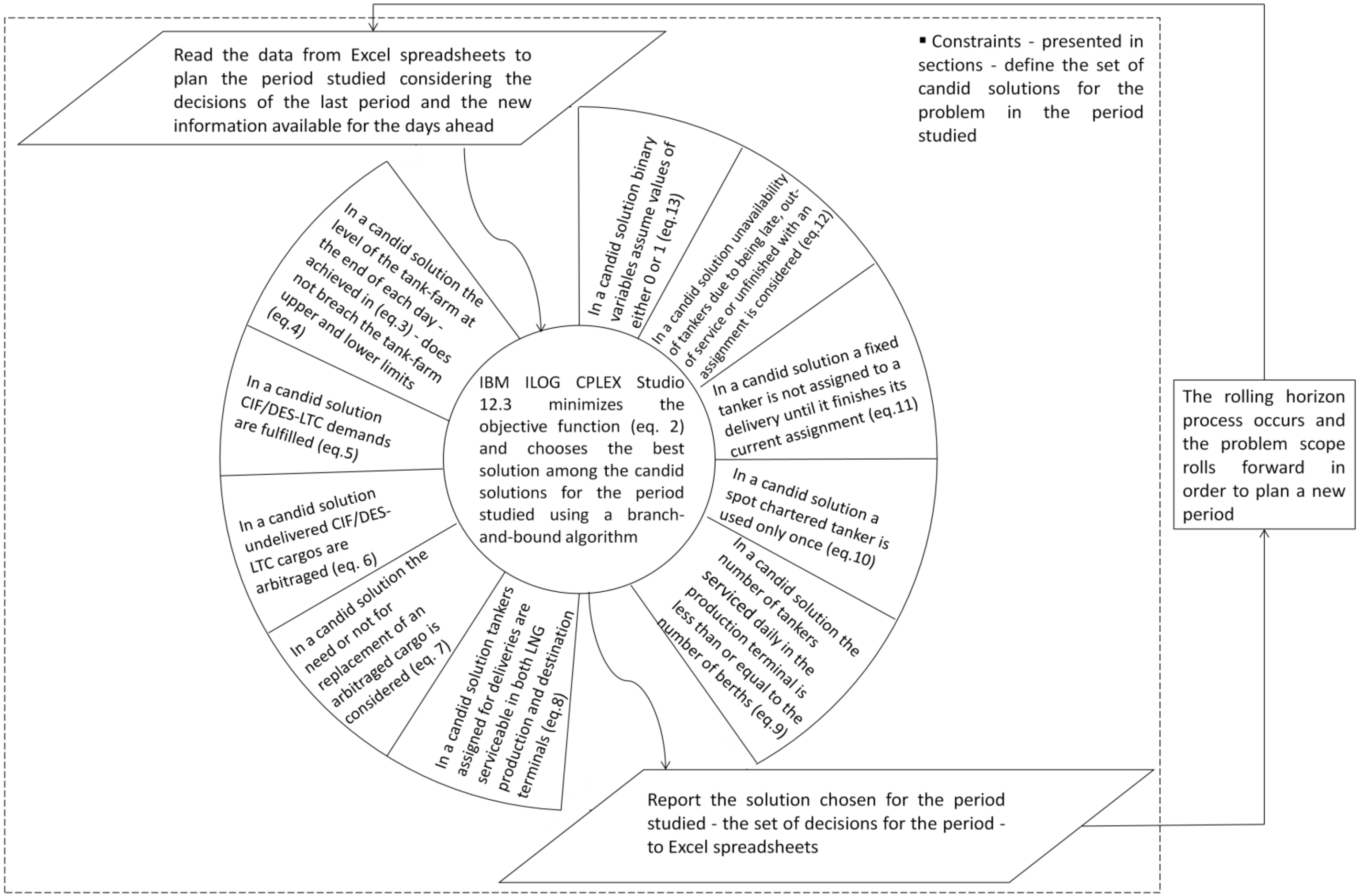


Figure 4.3 - the problem formulation and the rolling horizon process in perspective

Chapter 5

Scenario Analysis

5.1. Introduction

The model developed in the last chapter provides the opportunity to study the significance of different factors in the LNG business. As part of these studies, this chapter considers the importance of (spot sales in) arbitrage (5.2), variable interest rates and compounding frequencies on the profit in an LNG project (5.3 & 5.4). Also, the chapter presents an effort to study the consequences of spot price fluctuation plus simultaneous spot price and interest rate variations in decision-making for uncommitted product (spot) sales (5.5 & 5.6). Finally, a mathematical analysis for the model decisions for uncommitted product sales is suggested (5.7).

Numerical tests have been carried out using a set of real data originating from the industry[1]. The problem is as follows: there is a small LNG plant in the Middle East which delivers 80% of its annual production to three buyers with traditional LTCs and CIF/DES deliveries to their relevant regas terminal/destination; two US[2] buyers/destinations, with round trips of 40 and 35 days, respectively, and an East Asian buyer/destination with a round trip of 28 days. 11 fixed LNG tankers with capacities ranging between 138 000 to 165 000 cubic-meters fulfil the LTCs for the project. Of the 11 tankers, five fulfil the LTC for the first US buyer and three fulfil the LTCs with each of the second US and East Asian buyers. As a result of contractual obligations, each of these tankers can be used only for delivering cargos related to the contract to which they are dedicated, so a fixed tanker is either delivering a cargo to the respective destination of its LTC or is

[1] The data used in this section have been provided in confidence by a LNG producer who wishes to remain anonymous due to competition issues.

[2] Many of the contracts to the US are self-contracts but there are traditional LTCs to this country too. These contracts often cover the bottlenecks in certain regions (Jensen and Dickel, 2009).

used for arbitraging a cargo that was originally supposed to be delivered to the destination of its LTC. The rest of the annual production is sold OTC – uncommitted product sales – and is shipped solely by spot tankers with capacities of 150 000 cubic-meters each; spot tankers are available in sufficient numbers. There are two interested arbitrage/uncommitted product destinations, a European market with a return trip of 18 days and a South Asian market with a return trip of 9 days. More information about the industrial problem is presented in Appendix III, Tables III.1 to III.5.

The industrial mother problem discussed is used in the studies in the remainder of this chapter. However, there are some extra conditions which are defined as being test specific[1]; these conditions can be categorized into two groups.

First group: for tests with regards to arbitrage (5.2) and system costs with changing interest rates (5.3) and compounding frequencies (5.4), the following specifications are also taken into account. The study horizon consists of two successive periods of 75 days; consecutive periods are related to each other using a rolling horizon process that is rolled forward each 30 days. Of each time period only the first 30 days are executed and, hence, 60 days of the dates planned are implemented overall. The spot price (= SP_{hd}) of LNG in the European and South Asian markets are 430 \$/tonne[2] and 390 \$/tonne, respectively, for these tests. The split of revenues between the LNG producer and the LTC buyers in arbitrage is done in such a way that the LNG producer does not benefit from any extra income (= DI_{hdvs}) in dispatching to the South Asian market, while he makes \$45 more on each tonne of LNG by arbitraging cargos to the European market. It

[1] The range and magnitude of these specifications have been verified to be realistic by the LNG producer who provided the data, but are different from what took place in practice (due to concerns regarding competition).

[2] 430 \$/tonne is equal to 8.88 \$/MMbtu, given the density of LNG in the project.

is assumed that there is no need for cargo replacement in arbitrage, if it occurs (UP_{hds} = 0).

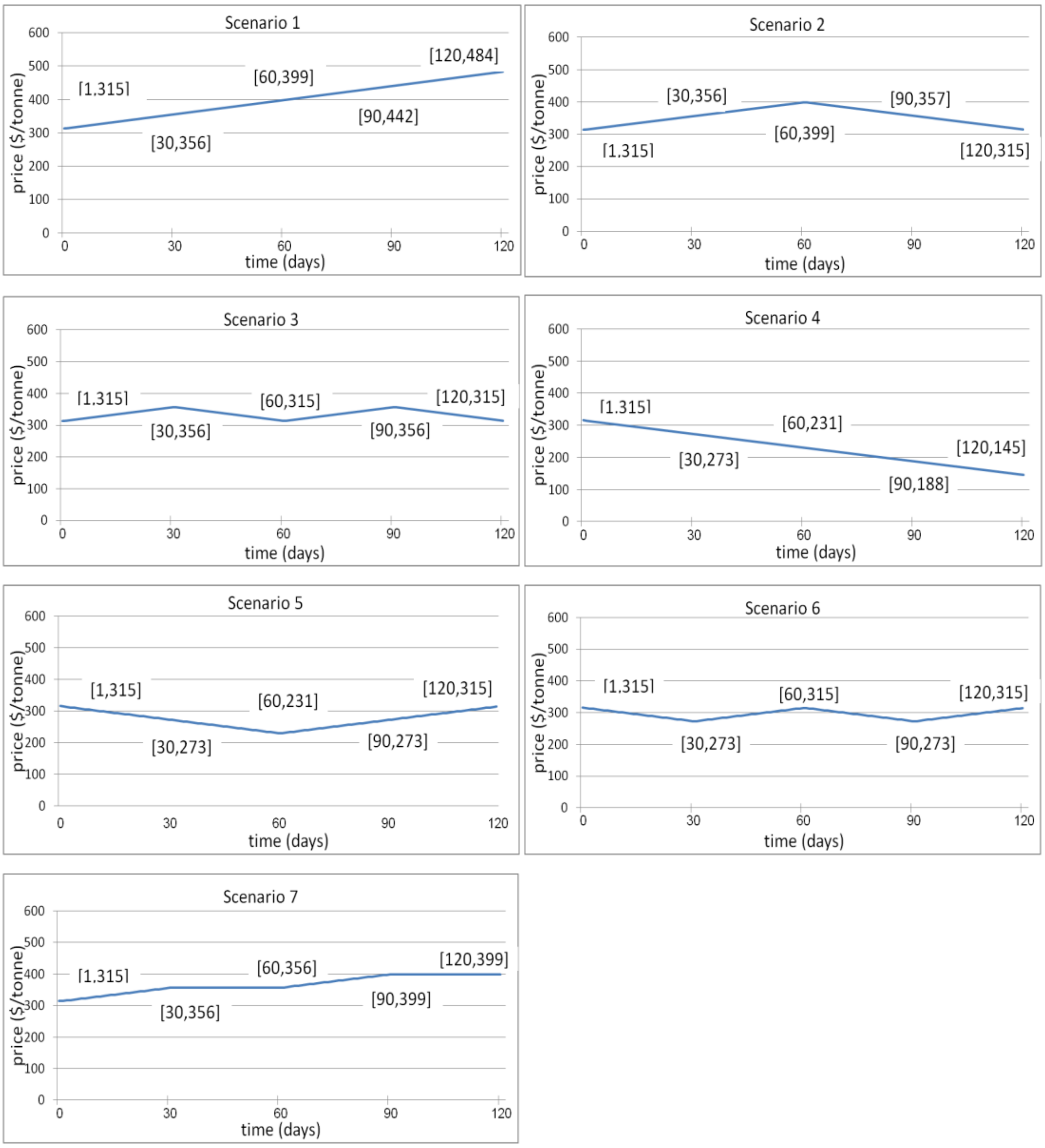


Figure 5.1 - Spot price scenarios for the European destination in tests of Sections 5.5 and 5.6

Second group: for spot trade of uncommitted product with price (5.5) and simultaneous price and interest rate variations (5.6), the extra conditions are as follows. There is a single uncommitted product destination in Europe for this group of tests. The potential destinations is cut to one here, since analysing the response of the LNG producer in these sales to variations in spot price of a single market is easier than for two markets.

Two markets may have contrasting spot price variation trends and, hence, mixed, complicated and hard to analyze effects on decisions for uncommitted product sales.

Seven spot price scenarios, as depicted in Figure 5.1, are defined for the uncommitted product destination in this group; these scenarios are used in the numerical tests accordingly. Scenario 1, in Figure 5.1, is rising, Scenario 2 has a crest on day 60, Scenario 3 has two crests on days 30 and 90, Scenario 4 is falling, Scenario 5 has one trough on day 60, Scenario 6 has two troughs on days 30 and 90, and finally Scenario 7 is a stair. The problem horizon in this group consists of two successive time periods, each of 90 days. Only the primary 30 days of each period are executed and the periods are related to each other using a rolling horizon process.

5.2. Importance of arbitrage in profit maximization

The significance of arbitrage in profit maximization is tested by solving five instances based on the problem discussed in the introduction to this chapter. To establish the instances, arbitrage is permitted for only some of the (CIF/DES-)LTC deliveries (= DD_{hd}) according to Table 5.1. The table states the number of deliveries that can be arbitraged for each LTC buyer and also the permitted arbitrage destination(s). As already mentioned two arbitrage destinations are defined for tests of Section 5.2, a European one (E in the table) and a South Asian one (S in the table).

East Asian markets are highly dependent on their LNG supply, in fact LNG is one of their primary sources of energy, hence, the chances of permitting arbitrage for their LTC deliveries is quite low, as is the case in Table 5.1. US markets, however, enjoy the supply of natural gas from diverse sources – including indigenous supply, inter-regional pipelines and LNG – therefore arbitrage can occur for the deliveries dedicated to these markets without risk of scarcity.

Table 5.1 - Characteristics of the problem instances for 5.2

Problem instances	LTC deliveries for arbitrage				
	First US buyer		Second US buyer		East Asian buyer
	No. of deliveries for arbitrage	Arbitrage destination(s)	No. of deliveries for arbitrage	Arbitrage destination(s)	No. of deliveries for arbitrage
I1	-	-	-	-	-
I2	4	S	-	-	-
I3	4	S	2	S	-
I4	4	S & E	-	-	-
I5	4	S & E	2	S & E	-

In designing the arbitrage instances in this section, the four LTC deliveries of the first US buyer – the second column of Table 5.1 – that can be arbitraged are the first four of his deliveries; see Appendix III, Table III.5 for the list of LTC deliveries. In a similar way, the two LTC deliveries of the second US buyer that can be arbitraged are the first two of his set of deliveries. This is a possible arrangement for arbitrage. It is possible that the beginning of winter in the US could be warmer than what was predicted, hence, the demand and price for gas in the region, which the LNG through a traditional LTC is imported for, falls. In such a situation the LTC buyer, given the demand for and price of LNG in other markets, may decide to arbitrage his first deliveries – those that are supposed to be received at the beginning of winter. Later, as winter deepens, temperatures fall and there are good prices for LNG, the LTC buyer returns to his normal business and receives his LNG in the US. At other times of the year the buyer given the circumstances, may conduct more arbitrage.

The interest rate (= IR) in the tests of Section 5.2 is 5%, and the instances in this section are compounded monthly (= CY). The branch-and-bound node limit in IBM ILOG CPLEX Optimization Studio 12.3 for all the instances is 500 000, while the relative MIP gap tolerance is 5% with other optimizer settings on default. The instances are solved on a 2.99 GHz Intel Core 2 Duo PC with 2 GB RAM. The number of continuous and binary variables for each period of 75 days of the problem in Section 5.2 is 976 and 61 380, respectively, while the number of constraints for the first and second periods in I1 (see Table 5.1) are, in that order, 166 532 and 166 540, in I2 are 166 710 and 166 540, in I3 are 166 796 and 166 540, in I4 are 166 620 and 166 540, and in I5 are 166 664 and 166 540. Table 5.2 provides the objective values/the controllable part of the profit, the difference in profit in comparison to problem instance I1, and the sum of computation time for the successive periods.

Table 5.2 - Results for problem instances of 5.2

Problems	Objective value ($)	Profit difference ($)	Sum of computation time (s)
I1	21 456 425	-	111
I2	36 720 612	15 264 187	115
I3	42 732 118	21 275 693	106
I4	48 955 020	27 498 595	113
I5	58 080 886	36 624 461	111

The LNG producer/data provider has not shared his decisions with the writer on tanker assignment in fulfilling the LTC deliveries or his decisions on uncommitted product sales and arbitrage. Hence, it is not possible to compare the results of the tests in this section, and the other sections of this chapter, with industry.

However, it is argued that the results are reasonable. In order to execute the LTC deliveries the model matches the delivery size to the fixed tanker that can carry it (according to the data set the delivery sizes are such that one tanker can/should transport each of them as a cargo; see Appendix III, Tables III.4 and III.5, respectively, for the sizes of the fixed tankers and the LTC deliveries) and assigns the matched tanker for each delivery. For example, in the case of a delivery of 67 500 tonnes (= 150 000 cubic-meters) on the 23rd day to the East Asian market, of the three fixed tankers that are dedicated to serve that market only the one which its capacity can carry this cargo, and that tanker is correctly assigned to that delivery. The list of tanker assignments for I1 in the 60 days of the combined periods planned that are implemented is presented in Appendix IV, Table IV.1. 16 tankers are dispatched for LTC deliveries in these 60 days. There is no need to mention that all the LTC deliveries should be and are correctly carried with fixed tankers and not spot tankers, as spot chartering a tanker is much more expensive than using a fixed tanker (see Appendix III, Tables III.3 and III.4, respectively, for the operational cost of fixed tankers and tanker spot chartering fees).

On arbitrage decisions, for I2 and I3 all the potential LTC deliveries for arbitrage are sold to the South Asian market. This is a rational choice since the profit of the LNG producer increases by delivering to this market. Here, the producer does not make any extra income by arbitraging to the South Asian market, as stated in Section 5.1, but this market is closer than both of the US destinations, and hence, tanker transport/trip costs are cheaper. Whilst retaining the same revenue/income and reducing transport costs the LNG producer should logically choose the South Asian market over the US destinations; this is the decision made and suggested by the model.

For both I4 and I5 all the LTC deliveries for arbitrage are sold to the European market. In these cases the LNG producer faces a choice between the US destinations and the South Asian and European markets. Given the discussions of the previous paragraph the US destinations are ruled out in favour of the South Asian market. In comparison between the European and South Asian markets it should be said that the European market is farther and, hence, has a higher travelling/trip cost but the extra income ($45/tonne) in Europe makes up for the extra costs, hence, Europe is a better choice than Asia.

In arbitraging the LTC deliveries in I2 to I5 the same fixed tanker that is used for transporting a cargo in problem instance I1, where no arbitrage is allowed, is also chosen for arbitraging that cargo. This is a rational choice given the size of arbitraged deliveries and possibility of using fixed tankers for arbitrage, as stated in 5.1, and the high cost of tanker spot chartering. The dispatch date of arbitraged LTC deliveries is the same as the dispatch date in I1 and this is sensible. It was discussed in the previous chapter (see 4.4.1.4) that an arbitraged cargo is dispatched in such a way that if it was required at the regas terminal of the LTC buyer at the designated time for it, it could be delivered there.

The sizes of the changes in profit due to arbitrage are reasonable. For example, in I2, where the first four cargos of the first US buyer are arbitraged to the South Asian market, the transport cost without considering the time value of money is $15 340 000 cheaper than in I1. This price difference is easily calculated given the tankers chosen for arbitrage and the transport cost to the first US buyer and the South Asian markets. Taking the downward effect of the interest rate into account, the suggested profit difference in Table 5.2 for I2 ($15 264 187) is achievable.

For all the cases of Section 5.2, during the 60 days of planning, which are executed, four uncommitted product cargos are sold in the spot market, typically on days 5, 27, 42 and 51, and all of them to the European destination. In contrast to the arbitrage markets, which for the sake of the tests in I2 and I3 are restricted to the South Asian market, for uncommitted product sales in all the tests (I1 to I5) both South Asian and European destinations are available. It is stated in Section 5.1 that 80% of the LNG plant's production, equal to 16 cargos on the 60 days which are executed, is dedicated to LTC buyers and 20% is uncommitted and sold in the spot market. Given the fact that the capacity of fixed and spot tankers – according to Section 5.1 spot tankers carry all the spot sales – are close, there is a correlation between the share of production dedicated to LTC deliveries and the uncommitted production share; and the number of cargos dispatched for each of these purposes. Therefore, four cargos ($= \frac{20 * 16}{80}$) as suggested by the model is a correct number for uncommitted product sales.

The choice of destination for spot sales of uncommitted product is reasonable, since like arbitrage, given the costs and revenues, dispatching to the European market is more profitable than dispatching to South Asia. The dates suggested for the uncommitted product sales, i.e. 5, 27, 42 and 51, of the problem instances of Section 5.2 are logical. The spot prices and transport costs to the uncommitted product destinations suggested are constant over the course of the studies, hence the profit of these sales are flat. Therefore, to avoid the operational cost of keeping LNG in the tank-farm of the production plant, the uncommitted product cargos should be dispatched as soon as possible. The dates suggested for uncommitted product sales in this section are the earliest possible dates. For example, for the first cargo of these sales, the volume of LNG in the tank-farm given an LTC delivery that is dispatched on the 3^{rd} day to the first US buyer does not allow its dispatch any earlier than the 5^{th} day – see Appendix IV, Figure IV.1 for the volume of LNG available in the tank-farm. The same kind of arguments suggested for validity of the decisions on LTC deliveries, arbitrage and uncommitted product sales in this section can be made for all the numerical tests in the other sections of this chapter.

In conclusion, looking at all the instances of Table 5.2 the profit has increased thus the LNG producer, given the advantageous spot prices, has benefited from arbitrage. The governing parameter in deriving results in I1 to I5 has been the relative MIP gap tolerance (5%) which means in all the instances before reaching the 500 000 node limit threshold, the determined relative MIP gap tolerance was fulfilled.

5.3. Role of interest rate in profit maximization

The significance of the interest rate in profit maximization is established by solving three cases. In the first case, the problem defined at the beginning of the chapter is compounded monthly with five interest rates, i.e. 0%, 1%, 5%, 10%, and 20%. In the second and third cases the problem is compounded daily and hourly, respectively, with the aforementioned interest rates. In this section, with regards to three LTC deliveries, arbitrage is permitted; the first two deliveries to the first US buyer and the first delivery to the second US buyer.

The branch-and-bound node limit and the relative MIP gap tolerance for the instances of 5.3 are 500 000 and 10%, respectively, with other optimizer settings on default. The problem instances are solved on a 2.99 GHz Intel Core 2 Duo PC with 2 GB RAM. The number of continuous and binary variables for each of the 75 days of the problem in Section 5.3 is 976 and 61 380, respectively, and the number of constraints for the first and second period of study are 166 598 and 166 540, respectively. The problem features mentioned in this paragraph, except for the relative MIP gap tolerance, are the same in the next section, hence, are not repeated.

Table 5.3 presents the objective values/the controllable part of the LNG project profit; decrease in profit in comparison to J1; computation times for the sum of the successive periods, and dispatch days for uncommitted product sales for the first case of study – with a monthly compounding frequency.

Table 5.3 - Results for the first study case of 5.3

Problem instance	Interest rate (%)	Objective value ($)	Decrease in objective value (%)	Decrease in profit ($)	Sum of computation times (s)	Dispatch days for uncommitted product sales
J1	0	34 747 755	-	-	105	5, 27, 42 & 51
J2	1	34 699 284	0.139	48 471	103	5, 27, 42 & 51
J3	5	34 581 017	0.480	166 738	105	5, 27, 42 & 51
J4	10	34 374 130	1.075	373 625	103	5, 29, 42 & 51
J5	20	34 036 964	2.046	710 791	104	5, 29, 42 & 51

In Table 5.3 and also the other tables in this section, J1 is the benchmark to which all the other instances are compared. In J1, 13 LTC deliveries are fulfilled while the three deliveries for arbitrage, taking into account the split of extra income, are all dispatched to the European market. With regards to the uncommitted merchandise available, in J1 the model suggests dispatching and selling four cargos which, given the spot prices, are all sent to the European market.

For the rest of the instances in this section, the decisions about LTC deliveries and cargo arbitrage, and also the number of uncommitted product cargos sold are similar to J1. The differences between the instances occur in the objective value function and, in some of them, the spot cargo dispatch days.

The differences between the instances of Table 5.3 are as follows: in J2, no variation in terms of dispatch days is detected, here the profit decreases $48 471. In J3, as in J2, there is no difference in dispatch days, while the profit decreases $166 738. In J4, an uncommitted product sale is delayed for 2 days and the profit decreases $373 625. Finally, in J5, the profit decreases $710 791 when an uncommitted product sale is delayed for 2 days. Table 5.4 suggests the same results as Table 5.3 for the second case of 5.3 – with a daily compounding frequency.

Table 5.4 - Results for the second study case of 5.3

Problem Instance	Interest rate (%)	Objective value ($)	Decrease in objective value (%)	Decrease in profit ($)	Sum of computation times (s)	Dispatch days for uncommitted product sales
J1	0	34 747 755	-	0	105	5, 27, 42 & 51
J6	1	34 683 065	0.186	64 690	117	5, 29, 42 & 51
J7	5	34 509 030	0.687	238 725	119	5, 27, 46 & 51
J8	10	34 414 501	0.959	333 254	114	5, 27, 42 & 51
J9	20	34 084 792	1.908	662 963	113	5, 27, 42 & 51

The results for the third case of Section 5.3 – with hourly compounding – are shown in Table 5.5.

Table 5.5 - Results for the third study case of 5.3

Problem instance	Interest rate (%)	Objective value ($)	Decrease in objective value (%)	Decrease in profit ($)	Sum of computation times (s)	Dispatch days for uncommitted product sales
J1	0	34 747 755	-	0	105	5, 27, 42 & 51
J10	1	34 698 666	0.141	49 089	120	6, 27, 42 & 51
J11	5	34 580 672	0.481	167 083	126	5, 27, 42 & 51
J12	10	34 372 710	1.079	375 045	119	5, 29, 42 & 51
J13	20	34 030 730	2.064	717 025	121	7, 27, 42 & 51

In all the instances (J1 to J13) the dominating parameter in determining the results has been the relative MIP gap tolerance (10%) and not the node limit. There is a limit to the size of the problems that solver software (IBM ILOG CPLEX Optimization Studio 12.3) can solve; increasing the magnitude of a problem due to a change in a factor or several factors may result in the software not solving the problem.

In the problem of Section 5.3, with three deliveries for arbitrage and for the range of interest rates and compounding frequencies suggested, a problem instance with 37 tankers, including 11 fixed and 26 spot tankers, is not solvable. In trying to solve this problem instance the computer runs out of memory in depicting the problem for itself and before starting the optimization process. The factor that is varied and thus creates the unsolvable instances in this chapter is the number of tankers.

In all three cases described in this section we can observe that higher interest rates lower the value of the objective function at the solution, therefore suggesting that the profit emanating from the entire LNG project has been reduced. However, the changes identified in the profit are relatively small, such that the biggest profit adjustment – equal to $717 025 for instance J13 – causes only 2% of a change in comparison to the *profit of instance J1. This small change, given the uncertainty in defining the other factors for the model , e.g. the travel times for each trip can be a little different from the times suggested in the data set and, hence, have a slightly different price from the suggested trip costs; this is minor compared to the scale of the monetary sums involved and not substantial in determining the profit.*

The instances of this section do not show any specific trend with regards to changes in the uncommitted product cargo selling decisions. Some of the differences observed among the examples in dispatch days of these cargos are due to the relative MIP gap tolerance in finding the solution. For example, the tests repeated for J7, J10 and J13, which have different dispatch days, in the next section in K9, K4 and K16, respectively, with a tighter relative MIP gap tolerance (10^{-4}) converge the uncommitted product cargo selling dates for all of them to 5, 27, 42 and 51, which are the typical cargo dispatch days for uncommitted product in Section 5.3. The new tests for these cases do not affect the observations stated in the last paragraph. Tables 5.3, 5.4, and 5.5 suggest the results are relatively unaffected by the frequency of compounding.

5.4. Compounding frequency in profit maximization

The importance of the frequency of compounding in profit maximization is tested by solving the problem defined at the beginning of this chapter in three sets of examples. The interest rate in the first set of examples is 1%, while it is 5% and 20% for the second and the third sets, respectively. In all the examples, the problem is compounded yearly, monthly, daily, hourly, by the minute, and by the second. In a similar way to the previous section, with regards to three LTC deliveries arbitrage is permitted; the first two deliveries of the first US buyer and the first delivery of the second US buyer.

It was understood from the primary tests that the effects of compounding frequencies are marginal when it comes to comparison hence, the relative MIP gap tolerance in Section 5.4 is chosen as 10^{-4} to make the results more accurate and reliable. Table 5.6 summarizes the results and shows objective values/the controllable part of the LNG project profit; decrease in profit in comparison to K1, and computation time for the sum of the consecutive periods for the first set of examples where the interest rate is 1%.

Table 5.6 - Results for the first set of examples in 5.4

Problem Instance	Compounding frequency	Objective value ($)	Decrease in objective value (%)	Decrease in profit ($)	Sum of computation times (s)
K1	1 (yearly)	34 699 436	-	-	307
K2	12 (monthly)	34 699 284	0.000439	152	310
K3	365 (daily)	34 699 271	0.000478	165	301
K4	8 760 (hourly)	34 699 270	0.000479	166	298
K5	525 600 (by the minute)	34 699 270	0.000479	166	498
K6	31 536 000 (by the second)	34 699 270	0.000479	166	328

In this section for all the problem instances (K1 to K6), the decisions with regards to fulfilment of LTC deliveries, cargo arbitrage and uncommitted product sales are similar. In all of these instances, 13 LTC deliveries are fulfilled, while three cargos for arbitrage and four cargos of uncommitted product are sold to the European market. The differences between the examples occur just in the profit.

In Table 5.6 for K2, K3, K4, K5 and K6 in comparison to K1 the profit decreases $152, $165, $166, $166 and $166, respectively. Table 5.7 suggests the same measurements as Table 5.6 but for the second set of examples where the interest rate is 5%.

Table 5.7 - Results for the second set of examples in 5.4

Problem instance	Compounding frequency	Objective value ($)	Decrease in objective value (%)	Decrease in profit ($)	Sum of computation times (s)
K7	1 (yearly)	34 584 704	-	-	331
K8	12 (monthly)	34 581 017	0.010661	3 687	327
K9	365 (daily)	34 580 683	0.011627	4 021	325
K10	8 760 (hourly)	34 580 672	0.011658	4 032	333
K11	525 600 (by the minute)	34 580 671	0.011661	4 033	482
K12	31 536 000 (by the second)	34 580 671	0.011661	4 033	331

Table 5.8 provides the results for the third set of instances where the interest rate is 20%.

Table 5.8 - Results for the third set of examples in 5.4

Problem instance	Compounding frequency	Objective value ($)	Decrease in objective value (%)	Decrease in profit ($)	Sum of computation times (s)
K13	1 (yearly)	34 142 673	-	-	337
K14	12 (monthly)	34 090 021	0.154212	52 652	331
K15	365 (daily)	34 084 792	0.169527	57 881	310
K16	8 760 (hourly)	34 084 620	0.170031	58 053	318
K17	525 600 (by the minute)	34 084 612	0.170054	58 061	311
K18	31 536 000 (by the second)	34 084 612	0.170054	58 061	312

The governing parameter in finding the answers in K1 to K18 has been the node limit number (500 000). The relative MIP gap tolerance is relatively small and is, therefore, not achieved in any of the cases. For the problem in Section 5.4 with three cargo arbitrages and for the range of interest rates and compounding frequencies, an instance with 35 tankers, including 11 fixed tankers and 24 spot tankers is not solvable. In attempting to solve this problem instance the computer runs out of memory due to the size of the branch-and-bound algorithm calculations – also known as the branch-and-bound tree – in the optimization process.

Given the results in all the tables of Section 5.4 it is seen that the objective values are starting to converge toward a specific amount when the compounding frequency increases, which means the effects of swap between primary compounding frequencies – e.g. 1 and 12 – far exceed that of the later frequencies – e.g. 8 760 and 525 600. In other words, there is a threshold after which the compounding frequency loses its significance in the examples considered. *In Section 5.4, by increasing the compounding frequency the profit has decreased, however the changes are marginal such that the biggest adjustment in profit is $58 061 for K18, which is equal to just 0.17% of alteration. Hence, as in the previous section, given the uncertainty in defining the parameters for the model, it does not seem that the compounding frequency has any considerable effect in determining the profit.* The dispatching decisions for uncommitted product sales as previously stated are similar in all the cases of this section.

5.5. Importance of price fluctuation in decision-making for uncommitted product sales

The significance of spot price rises and falls is tested by implementing the price scenarios of Figure 5.1 in three variants of the problem introduced at the beginning of this chapter. The first problem is the industrial case, for which 20% of its output is uncommitted and for spot sales; while the second and third problems have about 30% and 50% of production, respectively, uncommitted. No arbitrage is permitted in any of the cases. To produce the 30% and 50% cases, a set of random deliveries to LTC buyers were generated. These deliveries are presented in Appendix III, Tables III.6 and III.7.

The delivering time to the regas terminal of the buyers with LTCs with CIF/DES deliveries also the delivering time in the production plant to the buyers' tankers with LTCs with FOB deliveries is pre-determined. For LTC buyers with CIF/DES deliveries, given the usual small range in capacity for fixed tankers serving a typical LNG LTC and the fact that LTC deliveries normally only comprise one cargo, as is the case for all the LTC deliveries in this chapter; usually only one or one of the few identical fixed tankers, whose capacity matches the cargo, can carry that cargo. This implies that the dispatch time of the deliveries for LTCs with CIF/DES deliveries in many LNG projects is largely fixed, given the speed of the tanker(s) that can carry them and the fixed deliver time of the cargos to the LTC buyer. Hence, the study in this section and the next focuses on the flexible decisions, which are the uncommitted product sales.

An explanation is necessary for the second and third problems of this section. When LTC deliveries are evenly distributed across the year having 30% and 50% of production uncommitted in any period of time during the year is impossible. Since, as stated in Chapter 2, the proportion of uncommitted product in LNG projects is less than 20%. To the author's knowledge, an even distribution is typically the case for most LNG projects and LNG producers are interested in having this kind of arrangement for their projects as it makes the system more efficient.

However, if LTC deliveries are not evenly distributed across the year, having 30% or 50% of production, uncommitted to LTCs, for periods of time during the year is conceivable and realistic. The set of data used in this chapter is related to an LNG project with evenly distributed LTC deliveries across the year.

The branch-and-bound node limit for all the periods of Section 5.5 is 500 000, while the relative MIP gap tolerance is chosen to be 1%, with the rest of the optimizer settings on default. The problem instances are solved on a 2.99 GHz Intel Core 2 Duo PC with 2 GB RAM. The interest rate in all the calculations of Section 5.5 is 5%, while the instances are compounded monthly.

By implementing price scenarios of Figure 5.1 in the first problem with 20% of production uncommitted to any LTC, the results of Table 5.9 are achieved. This table includes the objective value (the controllable part of the profit) for the 60 days executed, computation time for each period, and dispatch days for uncommitted product sales again for the executed 60 days. In solving the first problem in each time period the number of continuous and binary variables is 1 171 and 45 357, respectively, and the number of constraints for the first and second periods of study is, correspondingly, 125 373 and 125 387.

Table 5.9 - Results for the first problem of Section 5.5 with 20% of production OTC

Price scenario no.	Objective value ($)	Period no.	Computation time (s)	Dispatch days for uncommitted product sales
1	14 639 204	1	174.03	8, 29, 47 & 53
		2	146.87	
2	14 639 204	1	176.13	8, 29, 47 & 53
		2	152.09	
3	7 999 119	1	220.98	8, 29, 42 & 51
		2	164.19	
4	-9 417 500	1	184.34	5, 27, 42 & 51
		2	169.95	
5	-9 417 500	1	198.88	5, 27, 42 & 51
		2	172.47	
6	-2 772 031	1	171	5, 27, 47 & 53
		2	171.69	
7	10 946 178	1	170.37	8, 29, 42 & 51
		2	155.69	

The governing parameter in solving all the instances of Table 5.9 has been the node limit (500 000). In this table, in Scenarios 1 and 2, the prices are rising for the first 60 days, hence, the uncommitted product sales take place as late as possible – on days 8, 29, 47 and 53 – in order to take advantage of higher prices. In Scenario 3, in the first 30 days, the prices are rising, while in the next 30 days they are falling, therefore, in the first half uncommitted product sales occur as late as possible – on days 8 and 29 – whereas in the second half they take place as soon as possible – on days 42 and 51. In Scenarios 4 and 5, the prices are falling in the first 60 days, hence, sales occur as soon as is feasible – on days 5, 27, 42 and 51. In Scenario 6, prices are falling for the first 30 days then rising for the next 30, therefore sales occur as soon as possible in the first half – on days 5 and 27 – whilst they take place as late as possible in the second half – days 47 and 53. Finally, in scenario 7, prices are rising for the first 30 days and they are flat for the second 30 days, hence sales in the first half occur as late as is feasible – on days 8 and 29 – while they are happen as soon as is feasible in the second half – days 42 and 51 – to avoid paying the extra inventory costs as a result of any delay in the sales.

Price scenarios of Figure 5.1 are implemented in the second problem of Section 5.5 – with 30% of production uncommitted to LTCs – and the respective results are presented in Table 5.10. In solving instances of the second problem, in each time period the number of continuous and binary variables is 1 171 and 45 357, respectively, and the number of constraints for the first and second periods of study is, correspondingly, 125 342 and 125 349.

The node limit factor (500 000) has governed the process of solution finding in all the periods of Table 5.10, which means that in none of them has the determined relative MIP gap tolerance has been achieved. Looking at this table and comparing it with Table 5.9, it can be seen that the tendencies of scenarios are the same. For example, in Scenario 1, like this scenario in Table 5.9, dispatches for uncommitted product sales are occurring as late as possible on days 11, 23, 32, 44 and 49 in order to take advantage of rising prices. In this scenario the number of cargos is five, one less than most of the other scenarios in Table 5.10; this is logical since the model decides to delay the last cargo to after day 60 to use the opportunity for better prices. Or, in another example that shows the similarity of tendencies in Scenario 2, six cargos are dispatched as late as possible – on days 11, 23, 32, 44, 49 and 60 – to use the rising prices in the first 60 days.

In this scenario the last cargo, the one which is missing from Scenario 1, is sold on day 59 since prices after that day are dropping.

Table 5.10 - Results for the second problem of Section 5.5 with 30% of production OTC

Price scenario no.	Objective value ($)	Period no.	Computation time (s)	Dispatch days for uncommitted product sales
1	46 614 030	1	170.72	11, 23, 32, 44 & 49
		2	181	
2	69 388 070	1	179.89	11, 23, 32, 44, 49 & 60
		2	180.41	
3	58 470 644	1	209.95	11, 23, 30, 38, 47 & 59
		2	162.38	
4	31 400 221	1	206.92	8, 17, 26, 38, 47 & 59
		2	178.73	
5	31 400 221	1	203.33	8, 17, 26, 38, 47 & 59
		2	186.63	
6	42 158 515	1	172.86	8, 17, 26, 44, 49 & 60
		2	202.94	
7	43 542 006	1	172.69	11, 23, 30, 38 & 47
		2	157.75	

The last problem of this section is a problem with 50% of production uncommitted to LTCs for the study periods; Table 5.11 outlines the problem results against the price scenarios of Figure 5.1. For this problem, in each time period the number of continuous and binary variables are 1 171 and 45 357, respectively, and the number of constraints for the first and second periods are 125 187 and 125 192, respectively.

In the last problem, in contrast to the previous problems, the governing parameter in solving the instances is the relative MIP gap tolerance (1%). The tendencies and arguments in Table 5.11 are similar to the previous tables of this section. For example, in Scenario 3 with a crest on the 30th day, in the rising part of the scenario/first 30 days, the cargos are sold late on days 8, 14, 18 and 25, while in the second part/next 30 days with falling prices, they are sold early on days 31, 35, 41, 44, 50 and 60.

Table 5.11 - Results for the third problem of 5.5 with 50% of production OTC

Price scenario no.	Objective value ($)	Period no.	Computation Time (s)	Dispatch days for uncommitted product sales
1	141 987 083	1	61.09	8, 14, 19, 26, 32, 38, 42, 49 & 52
		2	61.28	
2	164 081 919	1	61.09	8, 14, 20, 26, 31, 38, 43, 50, 53 & 60
		2	61.61	
3	147 911 635	1	61.72	8, 14, 18, 25, 31, 35, 41, 44, 50 & 60
		2	62.52	
4	103 782 091	1	66.14	5, 11, 17, 23, 29, 35, 41, 44, 50 & 59
		2	122.09	
5	103 630 893	1	62.47	5, 11, 17, 23, 30, 35, 41, 44, 50 & 59
		2	61.33	
6	102 575 696	1	61.14	5, 11, 17, 23, 29, 38, 44, 50 & 53
		2	61.08	
7	135 236 047	1	61.09	8, 14, 20, 26, 32, 37, 42, 49 & 51
		2	60.61	

It is observed in the cases of Section 5.5 that with increasing prices the uncommitted product sales are postponed, while with decreasing prices the uncommitted product cargos are preferably sold early. And the change in decision affects the profit in a meaningful way. For the main problem of Section 5.5, with 80% of annual production on LTCs, and given the price scenarios, the solver cannot work out a problem instance with 33 tankers – 11 fixed tankers and 23 spot chartered ones – is not solvable. Here, the computer runs out of memory due to the volume of the branch-and-bound tree in the optimization process.

5.6. Significance of interest rates in decision-making for uncommitted product sales in the presence of price fluctuation

To study the importance of interest rates in decision-making for uncommitted product sales, one of the problems of Section 5.5, with 50% of production on LTCs, is tested against different interest rates, i.e. 5%, 25%, 50%, 100%, 200% and 400%. A higher proportion of uncommitted output (50%) in comparison to other problems of Section

5.5 makes this problem more sensitive to changes in the interest rate. This is a positive point for the purpose of studies in this section.

Price Scenarios 1 and 4 of Figure 5.1 are implemented with each of the aforementioned interest rates. In these scenarios, the price slope does not change, hence, studying the interest rate effects is easier compared to the other scenarios. Some of the interest rates chosen for this study, such as 400%, are unlikely. But this is not important since in this section the aim is to study the nature of the interaction between the spot price and the interest rate in decision-making for uncommitted product sales. By solving the problem against price Scenario 1 the following results, Table 5.12, are achieved. The table contains the decisions for uncommitted product sales with respect to each interest rate.

Table 5.12 - Decisions for uncommitted product sales for price Scenario 1 in Section 5.6

Price scenario no.	Interest rate (%)	Dispatch days for uncommitted product sales
1	5	8, 14, 19, 26, 32, 38, 42, 49 & 52
	25	8, 14, 20, 26, 31, 37, 43, 50 & 52
	50	8, 13, 20, 26, 31, 37, 44, 50 & 53
	100	8, 14, 20, 26, 30, 38, 44, 50 & 51
	200	5, 12, 18, 24, 30, 35, 42, 50, 52 & 59
	400	5, 12, 17, 23, 29, 35, 41, 44, 50 & 60

In the above table, for interest rates 5%, 25%, 50% and 100%, nine cargos are sold, while with interest rates 200% and 400%, ten spot cargos are dispatched. Looking at the table, there is a clear change of trend in decisions on uncommitted product sales between 100% and 200% which produces a new strategy of sale. In the new strategy one cargo is added to the list of sales and the sales begin earlier. This cargo, perhaps with uncommitted product sales of 5% to 100%, is dispatched on a day after 60 but due to a new strategy which brings the sales forward for interest rates of 200% and 400%, it has shifted and occurs within the 60 executed days of the periods planned.

The reason for having this difference in strategy is that in each of the instances of Table 5.12 two factors are working against each other; the incentive of higher later prices, which encourages delaying the sales for a higher net present value, and the downward effect of the interest rate on the net present value of the sales, which pushes for earlier sales. With interest rates 5%, 25%, 50% and 100% the higher prices have a stronger effect compared to the interest rates. Hence, with these interest rates the uncommitted product sales, in comparison to examples with interest rates of 200% and 400%, are pushed to later days and the sales begin on the 8^{th} day. While with rates of 200% and 400%, the later higher prices lose the advantage to the downward effect of the interest rates. Hence, with these rates the selling decisions are brought forward and begin on the 5^{th} day.

The sharper the change in spot prices the higher would be the incentive for postponing the uncommitted product sales. Only a high interest rate and its generated downward effect can overcome such a sharp change in prices and push for beginning the sales sooner rather than later. However, with a small change in prices even a low interest rate can balance the effects of variations in price.

The use of such high interest rate values in the tests discussed in this section has been motivated by the need to demonstrate the latter as a property of the problem. Since the changes in prices are sharp, only high interest rates can show the interaction between the factors and the change of policy in sales. The same effect and change in policy is imaginable with reasonable interest rates and smooth changes in price. The problem in this section is also solved with price Scenario 4 and the results are presented in Table 5.13.

Table 5.13 - Decisions for uncommitted product sales for price Scenario 4 in Section 5.6

Price scenario no.	Interest rate (%)	Dispatch days for uncommitted product sales
4	5	5, 11, 17, 23, 29, 35, 41, 44, 50 & 59
	25	
	50	
	100	
	200	
	400	

According to Table 5.13, in all the cases the decisions have been the same. This is a logical outcome since in all the cases the later the cargos are sold the lower the spot prices, and also the stronger the downward effect of the interest rate. Hence, in all the instances the cargos are sold as soon as possible and the selling decisions are the same.

The studies of Section 5.6 showed that interest rates can be important in decision-making for uncommitted product sales in the presence of variations in price and changes in the spot sale strategy. An interesting question to answer would be the importance of this new strategy in profit making. Commenting on this aspect of the problem, given the high interest rates used in this section, is difficult and a set of new tests with new price scenarios are needed. This is one of the recommended expansions to this research in the next chapter.

5.7. Mathematical analysis of decision-making for uncommitted product sales

Timing of an uncommitted product sale is an important topic; in this section a mathematical analysis for these decisions in the presence of the time value of money factor and variations in spot price is presented. Imagine that the net present value – revenue minus the set of costs – of a specific uncommitted product cargo is calculated at the time of sale, and this value is named N. To discuss the possible decisions with regard to the time of sale of this cargo, the problem is divided into two groups; with a positive N and with a negative value for N.

5.7.1. An uncommitted product sale with a positive profit

An uncommitted product cargo sale with a positive profit (N) for the producer is a normal sale. To discuss the timing of the sale in more detail, here three sets are defined; set one with a constant N over time, set two with an increasing N over time, and set three with a decreasing N over time.

Before further discussions it should be mentioned that, the value of N can vary or stay constant due to reasons such as changes in the tanker and inventory costs and the spot price. However, an increase or decrease in the costs and revenue does not necessarily result in a bigger or smaller N. For example, with both a rising spot price and rising costs, if the slope of costs is sharper than the slope of price, N decreases over time. In Chapter 4, the present value formula – equation (1) – is used in discounting the values. This formula is the core for discussion in this section.

PV is the present value at time = t_1

FV is the future value at time = t_2

r denotes the nominal interest rate per period

m denotes the number of times the interest is compounded per period

t denotes the number of periods

$$PV = \frac{FV}{\left(1+\frac{r}{m}\right)^{mt}} \qquad (1)$$

Set 1, a constant N value over time: if N stays constant over time, i.e. the net present value of the cargo at the time of selling stays constant no matter when it is sold, then it would be logical to sell the uncommitted product cargo as soon as possible. Since the later the cargo is sold from the time of decision making – beginning of the period studied – the smaller would be its present value (= $\frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}$); N_1 (= N) is the value of the cargo at the time of sale and t_1 represents the time period between the decision-making moment and the time of sale.

Set 2, an increasing N value over time: if N increases over time, given the situation, it might be better to sell early, late or remain unchanged. Consider that a cargo with value N_1 (= N) can be sold at t_1; its present value at the time of decision-making would be $\frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}$. If the sale is delayed to time t_2, then its present value would be $\frac{N_1+a}{\left(1+\frac{r}{m}\right)^{mt_2}}$; a is the extra value which is added to N_1 between t_1 and t_2 ($t_2 > t_1$, N is increasing over time).

The uncommitted product sale should be delayed if $\left[\frac{N_1+a}{\left(1+\frac{r}{m}\right)^{mt_2}} - \frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}\right]$ is positive. This is the case for the first problem in Section 5.6 for interest rates 5%, 25%, 50% and 100%; with these interest rates the sales are delayed in comparison to sales for the examples with interest rates 200% and 400%. If $\left[\frac{N_1+a}{\left(1+\frac{r}{m}\right)^{mt_2}} - \frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}\right]$ is equal to zero, then the time of sale is not important. And finally, if the aforementioned equation is negative e.g. when a is relatively small and $t_2 >> t_1$ then the cargo should be sold early. This occurs for the instances with interest rates 200% and 400% compared to the other examples in Table 5.12.

Set 3, a decreasing N value over time: if N decreases over time then it is reasonable to sell as early as possible. Imagine that a cargo with value N_1 (= N) can be sold at t_1; its present value at the time of decision-making would be $\frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}$. If the sale is delayed, then N_1 decreases and t_1 increases which implies that it is better to sell as soon as possible. In Section 5.6 for the second problem in all the instances the uncommitted product cargos are sold as soon as possible, which is rational given the discussion in this example.

5.7.2. An uncommitted product sale with a negative profit

An uncommitted product sale with a negative profit (N) is not a normal sale but a forced one. This type of sale may happen when there is a lack of capacity for inventory and the producer has to sell, but at the same time the spot prices are fairly low. As in the previous case (5.7.1) three sets are defined: set one with a constant N over time, set two with an increasing N over time, and set three with a decreasing N over time.

Set 1, a constant N value over time: with a constant negative value over time, it would be better to sell as late as possible, since, in this way the negative present value of N at the time of decision-making is minimized.

Set 2, an increasing N value over time: with an increasing N over time, it would be logical to sell as late as possible, since both N_1 (= N) and t_1 in $\frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}$ increase, which results in a minimized negative present value for N.

Set 3, a decreasing N value over time: with a decreasing N, it might be better to sell early, late or remain unchanged. Imagine that a cargo with value N_1 (= N) can be sold at t_1; the present value of this deal at the beginning of the period would be $\frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}$. If this cargo is scheduled to be sold earlier in t_2 ($t_2 < t_1$), then the present value is $\frac{N_1+a}{\left(1+\frac{r}{m}\right)^{mt_2}}$; a with a positive value is the amount which N loses between t_2 and t_1. Here if $\left[\frac{N_1+a}{\left(1+\frac{r}{m}\right)^{mt_2}} - \frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}\right]$ is positive then selling earlier is rational; if $\left[\frac{N_1+a}{\left(1+\frac{r}{m}\right)^{mt_2}} - \frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}\right]$ is zero then there is no advantage to selling earlier or later; and finally if $\left[\frac{N_1+a}{\left(1+\frac{r}{m}\right)^{mt_2}} - \frac{N_1}{\left(1+\frac{r}{m}\right)^{mt_1}}\right]$ is negative, e.g. as a is rather small or r is large, then selling earlier is irrational.

5.8. Concluding remarks

In this chapter, given the model developed in the previous chapter, some of the factors and features governing the LNG business are studied. The importance of arbitrage is tested; numerical results prove that by using opportunities for arbitrage, the profit for the producer can increase considerably. The sensitivity of profit to the interest rate and compounding frequency is considered. Results for a set of tests – where no change of decisions is detected – did not show any considerable change in profit. In these tests the effects of interest rates were bigger than compounding frequency.

Decision-making for uncommitted product sales under price fluctuation is studied. Seven different price scenarios are defined and model decisions on the timing of sales is presented and analyzed. It is seen that increasing prices encourage the late sale of uncommitted product cargos, while decreasing prices push for an early sale. The simultaneous effects of price fluctuation and interest rate variation in decisions for uncommitted product sales are considered. It is observed that rising prices and increasing interest rates work against each other and one of them dominates and determines the timing and strategy for sales. Finally, timing of uncommitted product sales from an analytical perspective is examined and different cases are considered.

In the next chapter, some points and practical insights relating to the LNG business are derived. Also, a few recommendations for further development of this research are suggested.

Chapter 6

Conclusions and Further Research

6.1. Conclusions

This research led to the creation of a model for integrated decision-making in LNG production and distribution for profit maximization, as these two supply phases are managed by the same company. During the course of the research, several scientific topics were covered. Given the research objectives, outlined in the beginning of this work, the achievements of the study can be summarized as follows:

(1) It is established in Chapter 2 that the bulk of LNG is traded on LTCs (traditional ones with CIF/DES or FOB deliveries and self-contracts with CIF/DES deliveries). However, spot sale of LNG occurs in the sector too, for uncommitted product of the liquefaction plants to LTCs and in arbitrage of CIF/DES deliveries in traditional LTCs and particularly self-contracts.

(2) A survey of maritime IRPs is carried out in Chapter 3. The insights derived are instrumental in model development in Chapter 4. The main features of the MIP model are:

- Flexibility in accommodating operational requirements in running the LNG project, like bad weather or technical difficulties with the tankers/LNG plant and changes in the LTC buyers' demands. Using the model, the consequences of these issues can be predicted and managed.
- Having the option of hiring spot tankers, in addition to the fixed fleet, at a cost.
- Possibility of arbitrage which permits redirection of LTC cargos with CIF/DES deliveries to alternative markets by mutual agreement of the parties to the LTC.
- Possibility of selling the product that is not committed to LTCs OTC.

- The time value of money consideration in decision-making.

(3) Results of using the model developed for some analyses are reported in Chapter 5. The following practical insights are obtained from these tests:

- A set of tests in Section 5.2 proves that cargo arbitrage in traditional LTCs with CIF/DES deliveries can be beneficial to the producer and increase his profit. Unfortunately, usual traditional LTCs with CIF/DES deliveries, with a tight and strict destination clause make arbitrage quite difficult (this is a kind of contract rigidity) since with such a term, long negotiations between the LNG producer and the LTC buyer are needed before redirection of a cargo to an alternative destination can occur. Having these LTCs with a relaxed destination clause can make arbitrage a lot easier and quicker. Therefore, it is advisable for traditional LTCs to be written with a relaxed destination clause to facilitate arbitrage.

- A set of tests in Sections 5.3 and 5.4 proves that the effect of the time value of money on the profit of a project, where no change of decisions/strategy for sales and dispatching of cargos is observed, is very marginal and given the uncertainties in the LNG business is unimportant. For projects with evenly distributed LTC deliveries and without any arbitrage, it is imaginable that the time window for dispatching the uncommitted product sales/cargos – which according to Chapter 2 typically makes up to 10% of annual production – is very tight as there is a string of fixed LTC deliveries around each uncommitted product sale. Hence, a change of strategy by moving the dispatch time of these cargos is unlikely. Given this discussion it seems that for such LNG projects the time value of money does not play any important role in operational planning. This is the case for most of the LNG projects totally dedicated to East Asian markets in which no arbitrage is permitted; these include projects based in Australia, Indonesia, Malaysia and also some of the Middle Eastern ones.

The model presented in Chapter 4 is still valid and easily covers the state where the time value of money is not considered in calculations. In such a case the interest rate (= IR) should be zero and the number of cost clusters for fixed tankers (= f) needs to be defined as one.

- From the studies, it is found that there is a trade-off between the inventory and shipping costs and the prospect of higher revenues for the uncommitted product; this means it is economical to keep a uncommitted product cargo for a while and pay the extra inventory costs and possible higher future shipping costs if the future prices result in a higher profit on that cargo (Section 5.5). Of course keeping the product for very long periods is not possible since there are constraints with regards to vessel availability and inventory capacity, in other words at some point the producer has to sell not because there is no hope for a higher net profit but due to, for example, a lack of capacity for inventory.

6.2. Recommendations for further research

In this section several recommendations for further development of the research are proposed.

- In the LNG production and distribution model presented in this thesis, spot price is an input (see Section 5.1). A future contribution to this research can be the development of a spot price prediction model. Having such a model internationally does not seem to be possible since the LNG market is local rather than international (2.4.4), therefore the right approach would be to develop a model for each regional market, e.g. continental Europe. The combination of the model discussed in Chapter 4 and the proposed price predication one would be a very useful tool for decision-makers in the LNG sector.

- The LNG production and distribution model in Chapter 4 permits the arbitrage of CIF/DES deliveries in LTCs. Looking at equation (6) for the model it can be seen that the arbitrage is timed in such a way that the cargo dispatched for arbitrage could be delivered to the regas terminal of the LTC buyer at its designated time and fulfil the LTC demand. To the author's knowledge this is an acceptable arrangement since, given the logistical constraints, in many cases the same tanker that should have fulfilled the LTC delivery on the same day that it needed to leave for the LTC buyer's regas terminal, loads the arbitraged cargo and leaves the LNG plant (if the subject tanker has a really busy schedule and the new regas terminal is far from the plant – farther than the regas terminal of the LTC buyer – another tanker would need to be chosen). However, at the same time there are cases whereby dispatching of the arbitraged cargo occurs regardless of its designated delivery time to the LTC buyer. An expansion to the model could cover these states and permit arbitrage for all dispatch times.

- Due to the rigidity of some old traditional LTCs (as mentioned in 2.4.5), an LNG tanker that serves a LTC cannot participate in any activity other than its LTC. This causes inefficiency, since for example an idle LTC tanker which is controlled by the producer cannot be used for an uncommitted product sale and the producer has to spot charter a tanker at a high cost. In newer LTCs (traditional and self-contract) the rigidity on using LTC tankers has decreased and idle tankers can be used for other services provided that the profit is shared with others who have responsibility for the tanker (Flower, 2010). Given the model of Chapter 4, a set of tests can be designed and executed with which the importance of serving uncommitted product sales with idle LTC tankers that are controlled by the producer is studied. It is predicted that given the high cost of spot chartered tankers, using LTC tankers will result in a higher profit for the producer.

- Looking at the numerical tests in Chapter 5, it is seen that there is a limit to the magnitude of the problem instance that the solver/IBM ILOG CPLEX Optimization Studio 12.3 can solve. Thus a logical extension to this research would be the development of a heuristic algorithm that helps in tracing the calculations for bigger problem cases.

- A new set of tests with new price scenarios and reasonable interest rates should be carried out for a better understanding of the relation between profit and the time value of money in a case where a change of strategy in uncommitted product sales occurs. This could be the case of Section 5.6 where the LTC deliveries are not evenly distributed and hence there is the opportunity of moving the uncommitted product sales and having a different dispatch strategy.

  To do these tests with a range of reasonable interest rates for the problem of Section 5.6, the price scenarios should be designed to have mild increases in price and also each be slightly different. Even with a new strategy, a considerable change in profit is not predicted as the prices would be relatively flat and a change in sale dates does not seem to overly change the profit. Furthermore, with increasing profit for an uncommitted product sale by delaying it the downward effect of the interest rate also increases. If the tests confirm this prediction, then there is a good chance that the time value of money does not have a considerable role in any LNG production and distribution project – both with and without a change in strategy – at the operational level and hence, it can be ignored.

Publications Relating to this Work

Peer-Reviewed Journals

Nikhalat-Jahromi, H., Bell, M.G.H., A Study on the Importance of Price Fluctuation and Interest Rates on Liquefied Natural Gas Spot Sales, Maritime Policy & Management, submitted (2012)

Nikhalat-Jahromi, H., Bell, M.G.H., Optimizing Liquefied Natural Gas Sales at the Operational Level in a Production and Distribution Project}, Maritime Economics & Logistics, submitted (2012)

Conference Proceedings

Nikhalat-Jahromi, H., Bell, M.G.H., Farrell, S.P., Optimizing Liquefied Natural Gas Sales at the Operational Level in a Production and Distribution Project, TRB 2012, Washington, 22-26 January 2012

Nikhalat-Jahromi, H., Zavitsas, Z., Bell, M.G.H., El-hajj, M., Predicting the Future of LNG Market: A Review and Comparison of Oil and LNG Industries Performance Indicators and Risk Factors, IAME 2010, Lisbon, 7-10 July 2010

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Appendix I: The Mathematical Model

Objective function:

$$Min \sum_{h} \left\{ \sum_{t=1}^{FT} \sum_{d} \sum_{f} \frac{CT_{htdf}\, X_{htd}}{J(RT_{tdf})} + \sum_{t=1}^{FT} \sum_{d=1}^{CD} \sum_{f} \frac{CT_{htdf}\, Y_{htd}}{J(RT_{tdf})} \right.$$

$$+ \sum_{t=1}^{FT} \sum_{d=1}^{CD} \sum_{v} \sum_{s} \sum_{f} \frac{CT_{htvf}\, Z_{htdvs}}{J(RT_{tvf})} + \sum_{t=FT+1}^{PT} \sum_{d} \frac{SC_{htd}\, X_{htd}}{J(0)} + \sum_{t=FT+1}^{PT} \sum_{d=1}^{CD} \frac{SC_{htd}\, Y_{htd}}{J(0)}$$

$$+ \sum_{t=FT+1}^{PT} \sum_{d=1}^{CD} \sum_{v} \sum_{s} \frac{SC_{htv}\, Z_{htdvs}}{J(0)} - \sum_{t} \sum_{d} \frac{SP_{hd}\, CA_t\, DE\, X_{htd}}{J(H1_{td})}$$

$$- \sum_{t} \sum_{d=1}^{CD} \sum_{v} \sum_{s} \frac{DI_{hdvs}\, CA_t\, DE\, Z_{htdvs}}{J(H1_{tv})} + \sum_{t} \sum_{d=1}^{CD} \sum_{v} \sum_{s} \frac{UP_{hds}\, CA_t\, DE Z_{(h-H1_{td})tdvs}}{J(0)}$$

$$\left. + \frac{IC_h\, I_h + max(0, MI_2 - I_h)\, CS}{J(0)} \right\} \tag{2}$$

Constraints:

$$I_h = I_{h-1} + \left(\frac{PP_h}{DE}\right) - \sum_{t} \sum_{d} CA_t\, X_{htd} - \sum_{t} \sum_{d=1}^{CD} CA_t\, Y_{htd} - \sum_{t} \sum_{d=1}^{CD} \sum_{v} \sum_{s} CA_t\, Z_{htdvs}$$

$$- \left(\frac{DP_h}{DE}\right) \qquad \forall\, h \tag{3}$$

$$MI_1 \le I_h \le MI_3 \qquad \forall\, h \tag{4}$$

$$\frac{DD_{hd}}{DE} \left(1 - \frac{LV_{hd}}{100}\right) \le \sum_{t} CA_t\, Y_{(h-H1_{td})td} \le \frac{DD_{hd}}{DE}, \quad if\ DD_{hd} > 0 \qquad \forall\, h, d \in \{1, \dots, CD\} \tag{5}$$

$$\frac{DD_{hd}}{DE} - \sum_{t} CA_t \, Y_{(h-H1_{td})td} = \sum_{t}\sum_{v}\sum_{s} CA_t \, Z_{(h-H1_{td})tdvs} \,, \quad if \; DD_{hd} > 0 \quad \forall \, h, d \in \{1, \ldots, CD\} \tag{6}$$

$$\left.\begin{array}{c} \sum_{t}\sum_{v}\sum_{s=1} CA_t \, Z_{(h-H1_{td})tdvs} = 0 \\ or \\ \sum_{t}\sum_{v}\sum_{s=2} CA_t \, Z_{(h-H1_{td})tdvs} = 0 \end{array}\right\} \quad if \; DD_{hd} > 0 \quad \forall \, h, d \in \{1, \ldots, CD\} \tag{7}$$

$$\left.\begin{array}{l} CA_t \, Y_{htd} \leq min\,\{ MT_0, MT_d \} \quad \forall \, h, t, d \in \{1, \ldots, CD\} \\ CA_t \, X_{htd} \leq min\,\{ MT_0, MT_d \} \quad \forall \, h, t, d \\ CA_t \, Z_{htdvs} \leq min\,\{ MT_0, MT_v \} \quad \forall \, h, t, d \in \{1, \ldots, CD\}, v, s \end{array}\right\} \tag{8}$$

$$\sum_{t}\sum_{d} X_{htd} + \sum_{t}\sum_{d=1}^{CD} Y_{htd} + \sum_{t}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{htdvs} + NP_h \leq NB \qquad \forall \, h \tag{9}$$

$$\sum_{a=0}^{PH-h}\sum_{d} X_{(h+a)td} + \sum_{a=0}^{PH-h}\sum_{d=1}^{CD} Y_{(h+a)td} + \sum_{a=0}^{PH-h}\sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{(h+a)tdvs} \leq 1 \qquad \forall \, h, t \in \{FT+1, \ldots, FT+ST\} \tag{10}$$

$$\left.\begin{array}{l} F(x,y) + G(y-1) \leq H(y) \\ where: \\ \left.\begin{array}{lll} x = HH_{td} \quad and \quad y = X_{htd} \,, & & \forall \, h, t \in \{1, \ldots, FT\}, d \\ x = HH_{td} \quad and \quad y = Y_{htd} \,, & & \forall \, h, t \in \{1, \ldots, FT\}, d \in \{1, \ldots, CD\} \\ x = HH_{tv} \quad and \quad y = Z_{htdvs} \,, & & \forall \, h, t \in \{1, \ldots, FT\}, d \in \{1, \ldots, CD\}, v, s \end{array}\right\} \\ \quad \sum_{d} X_{htd} + \sum_{d=1}^{CD} Y_{htd} + \sum_{d=1}^{CD}\sum_{v}\sum_{s} Z_{htdvs} \leq 1 \qquad \forall \, h, t \in \{1, \ldots, FT\} \end{array}\right\} \tag{11}$$

$$\left.\begin{array}{l} \sum_{d=1}^{CD} \{Y_{htd} \leq UT_{ht}\} \\ \sum_{d} \{X_{htd} \leq UT_{ht}\} \\ \sum_{d=1}^{CD}\sum_{v}\sum_{s} \{Z_{htdvs} \leq UT_{ht}\} \end{array}\right\} \quad \forall \, h, t \tag{12}$$

$$\left.\begin{array}{ll} X_{htd} \in \{0,1\} & \forall\, h,t,d \\ Y_{htd} \in \{0,1\} & \forall\, h,t,d \in \{1,\ldots,CD\} \\ Z_{htdvs} \in \{0,1\} & \forall\, h,t,d \in \{1,\ldots,CD\},v,s \end{array}\right\} \tag{13}$$

Appendix II: Algorithm Implementation

This code is written and developed in IBM ILOG CPLEX Optimization Studio 12.3 (OPL Studio 12.3). It is written and saved in a file format named MOD. An auxiliary DAT file, built in OPL Studio 12.3, then connects the code to Excel spreadsheets which contain the data.

The process of running is such that Excel calls the DAT and code files and also the OPL Studio 12.3. The DAT file facilitates reading the data from the spreadsheets and feeding it into the code. Then the OPL Studio 12.3 using the code optimizes the problem, and the DAT file reports the results back to the spreadsheets. Repetition of this process permits the execution of the rolling horizon process.

```
/************************************
 * OPL 12.3 Model
 * Author: Hamed Nikhalat
************************************ /
/* LNG production and distribution project */

/*Defining the Indices*/

 int nd=...;
 range d1=1..nd;

 int dc=...;
 range d2=1..dc;

int nv=...;
 range v1=1..nv;

 int ndp=...;
 range h1=40+1..40+ndp;
 range h2=0..ndp+100;

range s1=1..2;

 int nt=...;
range t1=1..nt;
int lc=...;
int sc=nt-lc;
range t2=1..lc;
range t3=lc+1..lc+sc;

int nf=...;
range f1=1..nf;
```

/*Defining the Parameters*/

```
int Ca[t1]=...;

tuple Chtd {
      int h;
      int t;
      int d;
      int f;
    float c;
         }
{Chtd} tCd=...;
```

Reading parameters with more than two dimensions as tuples from Excel spreadsheets

```
tuple Chtv {
      int h;
      int t;
      int v;
      int f;
    float c;
         }
{Chtv} tCv=...;

float CSS[h1]=...;

int DD[h1][d2]=...;

float Convert=...;

int DH[h1]=...;

tuple DIhdvs {
     int h;
     int d;
     int v;
     int s;
   float di;
         }
{DIhdvs} tDI=...;

HTD[h1][d1]=...;

HTD1[h1][d1]=...;

HTV[h1][v1]=...;

HTV1[h1][v1]=...;

float I0=...;

float IC[h1]=...;

int LV[h1][d2]=...;

int minI2=...;

int minI1=...;

int maxI=...;

int Max1[0..nd]=...;

int Max2[v1]=...;

int n[h1]=...;

int nb=...;

int P[h1]=...;

tuple SCChtrd {
        int h;
        int t;
        int d;
     float scc;
            }
{SCChtd} tSCCd=...;

tuple SCChtv {
        int h;
        int t;
        int v;
     float scc;
            }
```

```
{SCChtv} tSCCv=...;

int SP[h1][d1]=...;
 tuple UPhds {
       int h;
       int d;
       int s;
    float up;
        }
{UPhds} tUP=...;

int UT[h1][t1]=...;

float IR=...;

int CY=...;

tuple RT1tdf {
       int t;
       int d;
       int f;
     int rt1;
         }
{RT1tdf} tRT1=...;

tuple RT2tvf {
       int t;
       int v;
       int f;
     int rt2;
         }
{RT2tvf} tRT2=...;
```

/* Defining the Decision Variables */

```
dvar float I[h1];
```

Defining the binary decision-variables / equation (13)

```
dvar int X[h2][t1][d1] in 0..1;

dvar int Y[h2][t1][d2] in 0..1;

dvar int Z[h2][t1][d2][v1][s1] in 0..1;
```

/* Pre-Processing */

Pre-processing is for converting the read tuples into arrays for use in the code.

```
//DI[h1][d2][v1][s1]
 {int} HDI = { h+40 | <h,d,v,s,di> in tDI };
 {int} DDI = { d | <h,d,v,s,di> in tDI };
 {int} VDI = { v | <h,d,v,s,di> in tDI };
 {int} SDI = { s | <h,d,v,s,di> in tDI };
 int DI[HDI][DDI][VDI][SDI];
execute {
 for(var di in tDI)
 { DI[di.h+40][di.d][di.v][di.s] = di.di };
 }
```

Converting a tuple into an array

```
//Cd[h1][t2][d1]
 {int} HCd = { h+40 | <h,t,d,f,c> in tCd };
 {int} TCd = { t | <h,t,d,f,c> in tCd };
{int} DCd = { d | <h,t,d,f,c> in tCd };
 {int} FCd = { d | <h,t,d,f,c> in tCd };
 float Cd[HCd][TCd][DCd][FCd];
execute {
 for(var c in tCd)
 { Cd[c.h+40][c.t][c.d][c.f] = c.c };
 }

//Cv[h1][t2][v1]
 {int} HCv = { h+40 | <h,t,v,f,c> in tCv };
 {int} TCv = { t | <h,t,v,f,c> in tCv };
{int} VCv = { v | <h,t,v,f,c> in tCv };
 {int} FCv = { v | <h,t,v,f,c> in tCv };
 float Cv[HCv][TCv][VCv][FCv];
execute {
 for(var c in tCv)
 { Cv[c.h+40][c.t][c.v][c.f] = c.c };
 }

//SCCd[h1][t3][d1]
 {int} HSCCd = { h+40 | <h,t,d,scc> in tSCCd };
```

```
 {int} TSCCd = { t | <h,t,d,scc> in tSCCd };
  {int} DSCCd = { d | <h,t,d,scc> in tSCCd };
 float SCCd[HSCCd][TSCCd][DSCCd];
execute {
 for(var scc in tSCCd)
 { SCCd[scc.h+40][scc.t][scc.d] = scc.scc }; }
//SCCv[h1][t3][v1]
 {int} HSCCv = { h+40 | <h,t,v,scc> in tSCCv };
 {int} TSCCv = { t | <h,t,v,scc> in tSCCv };
  {int} DSCCv = { v | <h,t,v,scc> in tSCCv };
 float SCCv[HSCCv][TSCCv][DSCCv];
execute {
 for(var scc in tSCCv)
 { SCCv[scc.h+40][scc.t][scc.v] = scc.scc };
 }

//UP[h1][d2][s1]
 {int} HUP = { h+40 | <h,d,s,up> in tUP };
 {int} DUP = { d | <h,d,s,up> in tUP };
 {int} SUP = { s | <h,d,s,up> in tUP };
 int UP[HUP][DUP][SUP];
execute {
 for(var up in tUP)
 { UP[up.h+40][up.d][up.s] = up.up };
 }

//RT1[t2][d1][f1]
 {int} TRT1 = { t | <t,d,f,rt1> in tRT1 };
{int} DRT1 = { d | <t,d,f,rt1> in tRT1 };
 {int} FRT1 = { f | <t,d,f,rt1> in tRT1 };
 int RT1[TRT1][DRT1][FRT1];
execute {
 for(var rt1 in tRT1)
 { RT1[rt1.t][rt1.d][rt1.f] = rt1.rt1 };
 }

//RT2[t2][v1][f1]
 {int} TRT2 = { t | <t,v,f,rt1> in tRT2 };
{int} VRT2 = { v | <t,v,f,rt1> in tRT2 };
 {int} FRT2 = { f | <t,v,f,rt1> in tRT2 };
 int RT2[TRT2][VRT2][FRT2];
execute {
 for(var rt2 in tRT2)
 { RT2[rt2.t][rt2.v][rt2.f] = rt2.rt2 };
 }
```

/* The Objective Function */

```
minimize
 sum(h in h1, t in t2, d in d1, f in f1) (Cd[h][t][d][f]*X[h][t][d]/((1+IR/CY)^(CY*((h+RT1[t][d][f])/365))))+
 sum(h in h1, t in t2, d in d2, f in f1) (Cd[h][t][d][f]*Y[h][t][d]/((1+IR/CY)^(CY*((h+RT1[t][d][f])/365))))+
 sum(h in h1, t in t2, d in d2, v in v1, s in s1, f in f1) (Cv[h][t][v][f]*Z[h][t][d][v][s]/((1+IR/CY)^(CY*((h+RT2[t][v][f])/365))))+
 sum(h in h1, t in t3, d in d1) (SCCd[h][t][d]*X[h][t][d]/((1+IR/CY)^(CY*(h/365))))+
 sum(h in h1, t in t3, d in d2) (SCCd[h][t][d]*Y[h][t][d]/((1+IR/CY)^(CY*(h/365))))+
 sum(h in h1, t in t3, d in d2, v in v1, s in s1) (SCCv[h][t][v]*(Z[h][t][d][v][s])/((1+IR/CY)^(CY*(h/365))))-
 sum(h in h1, t in t1, d in d1) (SP[h][d]*X[h][t][d]*Ca[t]/(Convert*(1+IR/CY)^(CY*((h+HTD1[t][d])/365))))+
sum(h in h1, t in t1, d in d2, v in v1, s in s1) ((Ca[t]/Convert*UP[h][d][s]*Z[h-HTD1[t][d]][t][d][v][s])/((1+IR/CY)^(CY*(h/365)))-
sum(h in h1, t in t1, d in d2, v in v1, s in s1) ((Ca[t]/Convert*DI[h][d][v][s]*Z[h][t][d][v][s])/((1+IR/CY)^(CY*((h+HTV1[t][v])/365))))+
 sum(h in h1) I[h]*IC[h]/((1+IR/CY)^(CY*(h/365)))+
 sum(h in h1) maxl(0, minI1-I[h])*CSS[h]/((1+IR/CY)^(CY*(h/365)));
```

Objective function / equation (2)

/* Constraints */

```
subject to {

 ctInventory1:
  I[41]==(I0+P[41]*Convert-sum(t in t1, d in d1) ((X[41][t][d])*Ca[t])-sum(t in t1, d in d2) ((Y[41][t][d])*Ca[t])-sum(t in t1, d in d2, v in v1, s in s1) ((Z[41][t][d][v][s])*Ca[t])-DH[41]*Convert);

 forall(h in 40+2..40+ndp)
 ctInventory2:
  I[h]==(I[h-1]+P[h]*Convert-sum(t in t1, d in d1) ((X[h][t][d])*Ca[t])-sum(t in t1, d in d2) ((Y[h][t][d])*Ca[t])-sum(t in t1, d in d2, v in v1, s in s1) ((Z[h][t][d][v][s])*Ca[t])-DH[h]*Convert);
```

Inventory balance constraint / equation (3)

```
forall (h in h1)
 ctTankFarmLevel:
  minI2 <= I[h] <= maxI;
```

Inventory limits constraint / equation (4)

```
 forall (h in h1, t in t1, d in d2)
 ctDemandandAssignements1:s
  if (DD[h][d]>0) {
  DD[h][d]*Convert*(1-(LV[h][d]/100))<=sum(t in t1) (Ca[t]*Y[h-HTD1[t][d]][t][d])<= DD[h][d]*Convert;
  };

 forall (h in h1, t in t1, d in d2)
 ctDemandandAssignements2:
```

CIF/DES-LTC demands fulfilment constraint + plus some extra code which helps in reducing the calculations for the OPL Studio 12.3 / equation (5)

```
 if (DD[h][d]==0) {
 Y[h-HTD1[t][d]][t][d]==0;  };
 forall (h in h1, t in t1, d in d2)

ctDemandandAssignements3:
 if (DD[h+HTD1[t][d]][d]==0) {
 Y[h][t][d]==0;
 };

ctServicePossibility:
 sum(h in h1) (P[h]+(I0-minI1)/Convert) >= sum (h in h1, d in d2) (DH[h]+DD[h][d]);
```

Continues to CIF/DES-LTC demands fulfilment constraint + plus some extra code which helps in reducing the calculations for the OPL Studio 12.3 / equation (5)

```
 forall (h in h1, d in d2)
 ctDivesrionAssignements1:
 if (DD[h][d]>0) {
 0.98*DD[h][d]*Convert-(sum(t in t1) (Ca[t]*Y[h-HTD1[t][d]][t][d])) <= sum(t in t1, v in v1, s in s1) (Ca[t]*Z[h-HTD1[t][d]][t][d][v][s]);
 1.02*DD[h][d]*Convert-(sum(t in t1) (Ca[t]*Y[h-HTD1[t][d]][t][d])) >= sum(t in t1, v in v1, s in s1) (Ca[t]*Z[h-HTD1[t][d]][t][d][v][s]);
 };

 forall (h in h1, t in t1, d in d2, v in v1, s in s1)
 ctDivesrionAssignements2:
 if (h-HTD1[t][d]<40+1) {
 Z[h-HTD1[t][d]][t][d][v][s]==0;
 };
```

Arbitrage constraints - the arbitraged product delivery constraint + plus some extra code which helps in reducing the calculations for the OPL Studio 12.3 / equation (6)

```
forall (h in h1, t in t1, d in d2, v in v1, s in s1)
 ctDivesrionAssignements3:
  if (DD[h][d]==0) { Z[h-HTD1[t][d]][t][d][v][s]==0; };
  forall (h in h1, t in t1, d in d2, v in v1, s in s1)

ctDivesrionAssignements4:
  if (DD[h+HTD1[t][d]][d]==0) {
  Z[h][t][d][v][s]==0;
  };
```

Continues to arbitrage constraints - the arbitraged product delivery constraint + plus some extra code which helps in reducing the calculations for the OPL Studio 12.3 / equation (6)

```
forall (h in h1, d in d2)
 ctDivesrionAssignements5:
  if (DD[h][d]>0) {
  sum(h in h1, t in t1, din d2, v in v1) Z[h][t][d][v][1]==0;
  };
```

Arbitrage constraints - a typical arbitrage type constraint / equation (7)

```
forall(h in h1, t in t1, d in d1)
 ctBerths1:
  if (Max1[d] < Max1[0]) {
  X[h][t][d]*Ca[t] <= Max1[d];
  } else {
  X[h][t][d]*Ca[t] <= Max1[0];
  }

 forall(h in h1, t in t1, d in d2)
 ctBerths2:
```

Berthing service constraints - berth capacity control / equation (8)

```
if (Max1[d] < Max1[0]) {
Y[h][t][d]*Ca[t] <= Max1[d];
} else {
Y[h][t][d]*Ca[t] <= Max1[0];
}

forall(h in h1, t in t1, d in d2, v in v1, s in s1)
ctBerths3:
if (Max2[v] < Max1[0]) {
Z[h][t][d][v][s]*Ca[t] <= Max2[v];
} else {
Z[h][t][d][v][s]*Ca[t] <= Max1[0]; }
```

Continues to berthing service constraints - berth capacity control / equation (8)

```
forall (h in h1)
ctBerths4:
sum(t in t1, d in d1) (X[h][t][d])+sum(t in t1, d in d2) (Y[h][t][d])+sum(t in t1, d in d2, v in v1, s in s1) (Z[h][t][d][v][s])<= nb-n[h];
```

Berthing service constraints - berth availability in the production plant / equation (9)

```
forall (h in h1, t in t3)
ctAvailability5:
sum(d in d1, x in 0..40+ndp-h) (X[h+x][t][d])+sum(d in d2, x in 0..40+ndp-h) (Y[h+x][t][d])+sum(d in d2, v in v1, s in s1, x in 0..40+ndp-h) (Z[h+x][t][d][v][s])<=1;
```

Tanker assignment constraints - spot chartered tanker service constraint / equation (10)

```
forall (h in h1, t in t2, d in d1)
 ctAvailability1:
  (2*nd*HTD[t][d]*(nv+1)*(X[h][t][d])+(sum(x in 0..HTD[t][d]-1, d in d1) (X[h+x][t][d]))+(sum(x in 0..HTD[t][d]-1, d in d2)
(Y[h+x][t][d]))+(sum(x in 0..HTD[t][d]-1, d in d2, v in v1, s in s1) (Z[h+x][t][d][v][s])))<= 2*nd*HTD[t][d]*(nv+1)+1;

 forall (h in h1, t in t2, d in d2)
 ctAvailability2:
  (2*nd*HTD[t][d]*(nv+1)*(Y[h][t][d])+(sum(x in 0..HTD[t][d]-1, d in d1) (X[h+x][t][d]))+(sum(x in 0..HTD[t][d]-1, d in d2)
(Y[h+x][t][d]))+(sum(x in 0..HTD[t][d]-1, d in d2, v in v1, s in s1) (Z[h+x][t][d][v][s])))<= 2*nd*HTD[t][d]*(nv+1)+1;

forall (h in h1, t in t2, d in d2, v in v1, s in s1)
 ctAvailability3:
  (2*nd*HTV[t][v]*(nv+1)*(Z[h][t][d][v][s])+(sum(x in 0..HTV[t][v]-1, d in d1) (X[h+x][t][d]))+(sum(x in 0..HTV[t][v]-1, d in d2)
(Y[h+x][t][d]))+(sum(x in 0..HTV[t][v]-1, d in d2, v in v1, s in s1) (Z[h+x][t][d][v][s])))<= 2*nd*HTV[t][v]*(nv+1)+1;

forall (h in h1, t in t2)
 ctAvailability4:
  sum(d in d1) (X[h][t][d])+sum(d in d2) (Y[h][t][d])+sum(d in d2, v in v1, s in s1) (Z[h][t][d][v][s])<=1;
```

Tanker assignment constraints - fixed tankers service constraint / equation (11)

```
forall (h in h1, t in t1)
ctBeingoff-service:
  sum(d in d1) (X[h][t][d]=U[h][t]);
  sum(d in d2) (Y[h][t][d]=U[h][t]);
  sum(d in d2, v in v1, s in s1) (Z[h][t][d][v][s]=U[h][t]);
```

Tanker assignment constraints - constraint for tanker unavailability due to being late, out-of service or unfinished with an assignment / equation (12)

Binary decision- variables are defined before.};

/* Post-Processing */

Post-processing for converting the multidimensional decision-variables, i.e. Y[h][t][d], X[h][t][d] and Z[h][t][d][v][s] to tuples. These tuples along I[h] are reported by the DAT file to Excel spreadsheets.

```
tuple YtP {
 int h;
 int t;
 int d;
 int Y;
 }
 {YtP} YP = { <h-40,t,d,Y[h][t][d]> | h in h1, t in t1, d in d2 };

tuple XtP {
 int h;
 int t;
 int d;
 int X;
 }
 {XtP} XP = { <h-40,t,d,X[h][t][d]> | h in h1, t in t1, d in d1 };

tuple ZtP {
 int h;
 int t;
 int d;
 int v;
 int s;
 int Z;
 }
 {ZtP} ZP = { <h-40,t,d,v,s,Z[h][t][d][v][s]> | h in h1, t in t1, d in d2, v in v1,
s in s1 };
```

Converting a decision-variable from an array to a tuple.

Appendix III: Data Set

Table III.1 - Specifications for the LNG liquefaction plant and the regas terminals

Feature	Unit	Value
Cost of safety stock level fall (CS)*	No Safety stock volume is kept in this plant	
Density of LNG (DE)	tonnes/cubic-meters	0.45
FOB-LTC demands (DP_h) and arrived tankers in the production plant for these demands (NP_h)	There are no such demands for the plant	
Inventory cost for LNG at the production port (IC_h)	\$/cubic meters/day	0.1
Primary tank-farm level at the beginning of the first period (IB)**	cubic-meters	50 000
Minimum permitted stock level ($MI_1 = MI_2$)	cubic-meters	1 000
Tank-farm capacity (MI_3)	cubic-meters	2 * 140 000
Maximum serviceable tanker in the LNG production and all the regas terminals ($MT_0 = MT_d = MT_v$)	cubic-meters	165 000
Number of berths in the LNG production plant (NB)	Berth	1
LNG production (PP_h)	tonnes/day	22 875

** It is assumed that no failure occurs in the Trains over the course of the tests.*

** The primary level of a tank-farm at the beginning of the second period is the level of the tank-farm at the end of the 30-day episode (in this problem) of the primary period that is executed.

Table III.2 - Travelling times for all the tankers*

Destination	Total trip duration	
	Outward leg	Return leg
First US buyer's regas terminal	40	
	20	20
Second US buyer's regas terminal	35	
	18	17
East Asian buyer's regas terminal	28	
	14	14
Asian arbitrage/uncommitted product destination	9	
	5	4
European arbitrage/uncommitted product destination	18	
	9	9

* According to the LNG producer, travel times to the same destination are equal for all tankers. For uncommitted product and LTC destinations the total trip duration is HH_{td} and outward/return legs are $H1_{td}$ and $H2_{td}$, respectively, in the calculations. For arbitrage destinations the total trip duration is HH_{tv} and outward/return legs are $H1_{tv}$ and $H2_{tv}$, respectively. The study assumes that there is no delay in the trips undertaken by the tankers, and that no fixed tanker has a technical problem or needs dry-docking.

Table III.3 - Cost and capacity specifications for a spot tanker

Capacity in cubic meters (CA_t)	A trip cost ($)*	
	Destination	($)
150 000	First US buyer's regas terminal	8 200 000
	Second US buyer's regas terminal	7 190 000
	East Asian buyer's regas terminal	5 840 000
	Asian arbitrage/spot destination	1 690 000
	European arbitrage/spot destination	4 040 000

* The spot chartering cost (a trip cost) is assumed to be constant. The spot chartering cost to uncommitted product and LTC destinations is given by SC_{htd} and the cost for arbitrage destinations is given by SC_{htv}.

Table III.4 - Cost and capacity specifications for the fixed tankers

Tanker no.	Capacity in cubic-meters (CA_t)	Dedicated to	Service type	Trip cost to the LTC destination ($)*	Trip cost to the European arbitrage destination ($)*	Trip cost to the Asian arbitrage destination ($)*
1	156 100	The LTC with the second US buyer	Time charter	3 830 000	2 340 000	820 000
2	156 100		Time charter	3 830 000	2 340 000	820 000
3	150 900		Time charter	3 830 000	2 340 000	820 000
4	145 000	The LTC with the East Asian buyer	Time charter	3 160 000	2 340 000	820 000
5	151 800		Time charter	3 160 000	2 340 000	820 000
11	150 000		Time charter	3 160 000	2 340 000	820 000
6	165 000	The LTC with the first US buyer	Bareboat charter	5 180 000	2 720 000	1 010 000
7	165 000		Bareboat charter	5 180 000	2 720 000	1 010 000
8	138 000		Time charter	4 320 000	2 340 000	820 000
9	145 000		Time charter	4 320 000	2 340 000	820 000
10	145 000		Time charter	4 320 000	2 340 000	820 000

* The operational cost of a fixed tanker for a trip, assumed to be constant in this study, is split between the outward and return legs of the journey. This split defines the cost clusters, i.e. CT_{htdf} in delivering to LTC destinations and CT_{htvf} in delivering to arbitrage destinations for fixed tankers. The resulting cost cluster time, expressed by the variable RT_{tdf} for LTC deliveries and RT_{tvf} for arbitrage deliveries, is provided in Table III.2.

Table III.5 - The LTC deliveries (DD_{hd}) before permission for any arbitrage*

No.	Dates for deliveries	LTC destination	Magnitude in tonnes	Volume in cubic-meters
1	23	First US buyer's regas terminal	65 250	145 000
2	23	East Asian buyer's regas terminal	67 500	150 000
3	31	Second US buyer's regas terminal	70 245	156 100
4	35	First US buyer's regas terminal	74 250	165 000
5	39	First US buyer's regas terminal	74 250	165 000
6	38	East Asian buyer's regas terminal	68 310	151 800
7	46	First US buyer's regas terminal	65 250	145 000
8	48	Second US buyer's regas terminal	70 245	156 100
9	53	First US buyer's regas terminal	62 100	138 000
10	55	Second US buyer's regas terminal	67 905	150 900
11	55	East Asian buyer's regas terminal	65 250	145 000
12	64	First US buyer's regas terminal	65 250	145 000
13	67	Second US buyer's regas terminal	70 245	156 100
14	74	East Asian buyer's regas terminal	67 500	150 000
15	75	First US buyer's regas terminal	74 250	165 000
16	79	First US buyer's regas terminal	74 250	165 000
17	82	East Asian buyer's regas terminal	68 310	151 800
18	86	First US buyer's regas terminal	65 250	145 000
19	91	Second US buyer's regas terminal	70 245	156 000
20	97	First US buyer's regas terminal	62 100	138 000
21	97	Second US buyer's regas terminal	67 905	150 900
22	102	East Asian buyer's regas terminal	67 500	150 000
23	105	First US buyer's regas terminal	65 250	145 000
24	112	Second US buyer's regas terminal	70 245	156 100
25	116	First US buyer's regas terminal	74 250	165 000
26	120	East Asian buyer's regas terminal	65 250	145 000

*The study horizon consisting of two time periods for the tests of first group - see Section 5.1 - is 105 days; here, each period is 75 days and the rolling horizon occurs every 30 days, hence the problem horizon for these tests would be 105 (= 75 + 30) days. Given this horizon, tests of first group cover the LTC demands listed in the above table up to row 23 only, as the delivery day for rows 24 to 26 would be later than day 105.

The study horizon for the tests of second group is 120 days, consisting of two time periods each of 90 days with the rolling horizon every 30 days. These tests cover all the demands listed in the above table.

Table III.6 - The designed LTC deliveries for the problem with 30% of production OTC

No.	Dates for deliveries	LTC destination	Magnitude in tonnes	Volume in cubic-meters
1	23	First US buyer’s regas terminal	62 100	138000
2	21	East Asian buyer’s regas terminal	68 310	151800
3	30	Second US buyer’s regas terminal	70 245	156100
4	34	Second US buyer’s regas terminal	70 245	156100
5	38	Second US buyer’s regas terminal	67 905	150900
6	45	First US buyer’s regas terminal	65 250	145000
7	43	East Asian buyer’s regas terminal	65 250	145000
8	47	East Asian buyer’s regas terminal	67 500	150000
9	51	East Asian buyer’s regas terminal	68 310	151800
10	61	First US buyer’s regas terminal	65 250	145000
11	65	First US buyer’s regas terminal	62 100	138000
12	68	Second US buyer’s regas terminal	70 245	156100
13	72	Second US buyer’s regas terminal	70 245	156100
14	76	Second US buyer’s regas terminal	67 905	150900
15	77	East Asian buyer’s regas terminal	67 500	150000
16	81	East Asian buyer’s regas terminal	68 310	151800
17	91	First US buyer’s regas terminal	65 250	145000
18	98	East Asian buyer’s regas terminal	74 250	165000
19	101	First US buyer’s regas terminal	74 250	165000
20	103	Second US buyer’s regas terminal	70 245	156100
21	108	First US buyer’s regas terminal	65 250	145000
22	114	Second US buyer’s regas terminal	70 245	156100
23	119	First US buyer’s regas terminal	62 100	138000

Table III.7 - The designed LTC deliveries for the problem with 50% of production OTC

No.	Dates for deliveries	LTC destination	Magnitude in tonnes	Volume in cubic-meters
1	24	First US buyer’s regas terminal	65 250	145 000
2	24	East Asian buyer’s regas terminal	68 310	151 800
3	30	East Asian buyer’s regas terminal	67 500	150 000
4	40	Second US buyer’s regas terminal	67 905	150 900
5	48	First US buyer’s regas terminal	65 250	145 000
6	52	Second US buyer’s regas terminal	70 245	156 100
7	54	East Asian buyer’s regas terminal	68 310	151 800
8	65	Second US buyer’s regas terminal	70 245	156 100
9	76	First US buyer’s regas terminal	65 250	145 000
10	72	East Asian buyer’s regas terminal	67 500	150 000
11	86	First US buyer’s regas terminal	74 250	165 000
12	91	First US buyer’s regas terminal	65 250	145 000
13	91	East Asian buyer’s regas terminal	68 310	151 800
14	105	Second US buyer’s regas terminal	70 245	156 100
15	107	Second US buyer’s regas terminal	70 245	156 100
16	118	First US buyer’s regas terminal	74 250	165 000
17	120	First US buyer’s regas terminal	62 100	138 000

Appendix IV: Optimisation Outputs for Section 5.2

Table IV.1 - Tanker assignment for fulfilling the LTC demands for I1 (see Table 5.1)

No.*	Tanker assignment by no.**	Dispatch day	Volume in cubic-meters
1	9	3	145 000*
2	11	9	150 000
3	1	13	156 100
4	6	15	165 000
5	7	19	165 000
6	5	24	151 800
7	10	26	145 000
8	2	30	156 100
9	8	33	138 000
10	3	37	150 900
11	4	41	145 000
12	9	44	145 000
13	1	49	156 100
14	11	60	150 000
15	6	55	165 000
16***	7	59	165 000

* The row numbers in this table and Table III.5 in Appendix III are the same; tanker row one in this table is dispatched to fulfil the delivery of row one in Table III.5.

** For tanker numbers please refer to Appendix III, Table III.4.

*** Upon dispatching the 16th tanker the assignment plan exceeds the initial 60 day execution window.

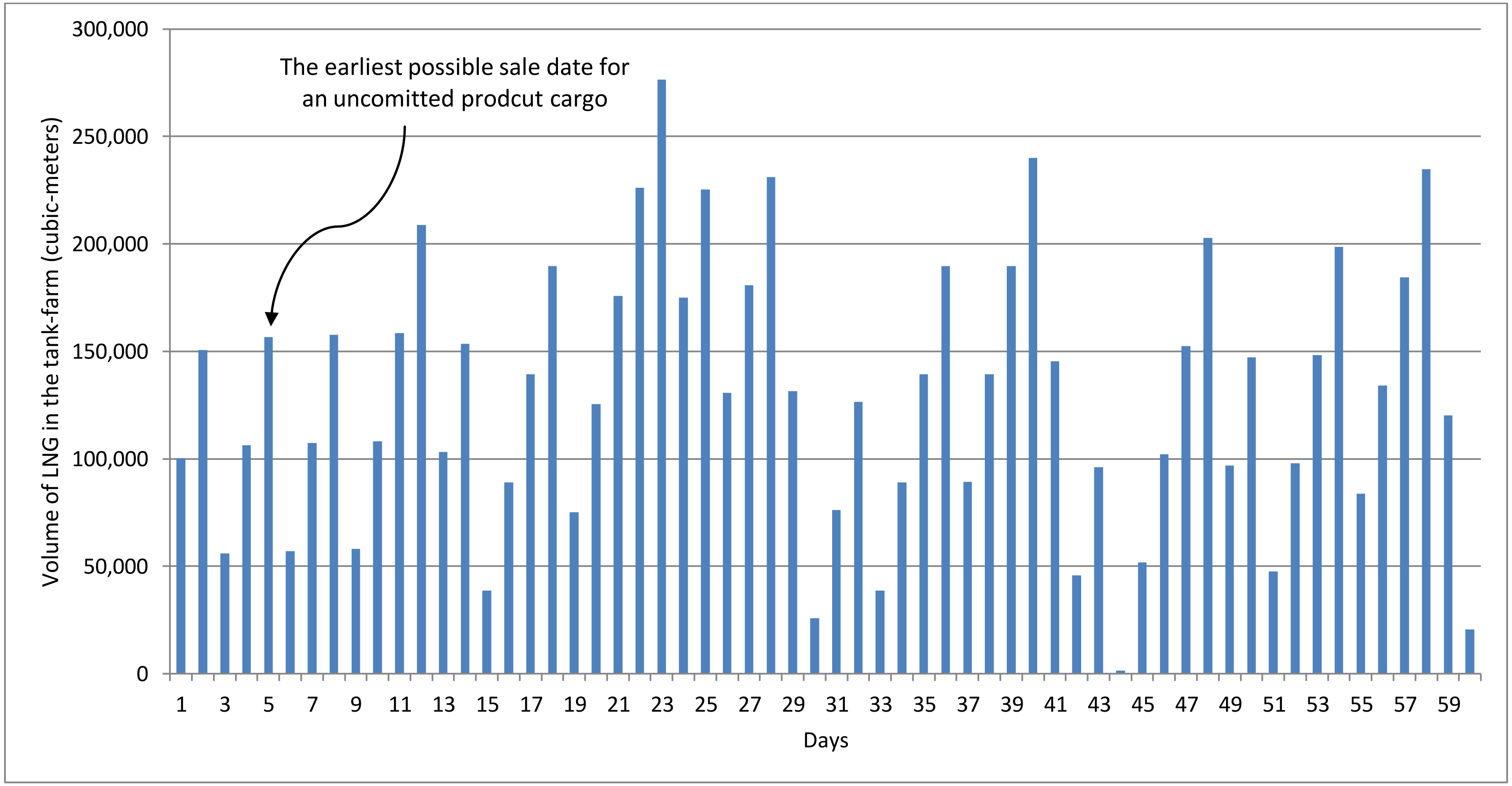

Figure IV.1 - Tank-farm level at the end of each day in cubic-meters (I_h) for the 60 executed days of the problem of Section 5.2