SCHEDULING OF UNLOADING, INVENTORY AND DELIVERY OPERATIONS AT AN LNG RECEIVING TERMINAL

RAJNISH KUMAR

(Bachelor of Technology, Chemical Engineering)

A THESIS SUBMITTED FOR THE

DEGREE OF MASTER OF ENGINEERING

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DECLARATION

I hereby declare that this thesis is my original work and it has been written by me in its entirety. I have duly acknowledged all the sources of information which has been used in the thesis.

This thesis has also not been submitted for any degree in any university previously.

RAJNISH KUMAR

22-FEB-2015

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Summary

Faced with the fast depletion of crude oil reserves, high oil prices in recent times, stringent environmental restrictions on CO_2 emissions, trends to diversify the energy supply, barriers to development of feasible renewable energy sources, etc., countries are now moving toward NG as their major and/or alternate source of fuel to supplement energy demand and curb the over dependency on oil [1-3]. However, Most NG reserves are offshore and away from demand sites. Pipelines pose a security risk and are not always feasible or economical. They are often limited by a “ceiling” amount of NG that can be transported. Alternately, an attractive option is to liquefy NG at -163^{o} C at the source and then transport it as liquefied natural gas (LNG) by specially built ships or tankers that are essentially giant floating flasks. When liquefied, the volume of natural gas reduces by a factor of about 600 at room temperature, which facilitates the bulk transport of NG. In fact, LNG is the most economical means of transporting NG over distances more than 2200 miles onshore and 700 miles offshore .

As an alternate fuel, the demand of LNG is doubling every 10 years. A growth rate of 6.5% per year is expected for LNG in the near future, which would be the fastest growth for any energy activity or product worldwide [3]. New open-access, multi-user LNG terminals are already been built in Asia, capable of importing and re-exporting LNG from multiple suppliers. The terminal is to cater to carriers of size 120,000 m^3 to 265,000 m^3

and will supply pipeline gas for purposes of power generation. A tertiary jetty is also expected to be set up for purposes for reloading LNG into ships for use as fuel via a bunkering operation. With its excellent location coupled with the upcoming IMO regulations on sulphur and price competitiveness of LNG with respect to HFO can help Singapore emerge as a global bunkering hub for LNG.

In recent years, new market dynamics such as rapidly increasing spot transactions and the emergence of new players, third parties and customers have made the LNG market dynamic, and thus LNG terminal operations quite complex. Further, LNG regasification costs have more than doubled. Soaring operations and energy costs, availability challenges, and growing demand for yield, require LNG regasification plants to achieve high throughput rates, while improving energy efficiency, safety, and reducing emissions [4-6]. This has led to the need for developing decision support systems which examine design parameters for an LNG receiving terminal – the LNG tanker docking facility, storage tanks and the regasification facility, to determine their relationships and help optimize tanker scheduling, terminal utilization, and profitability.

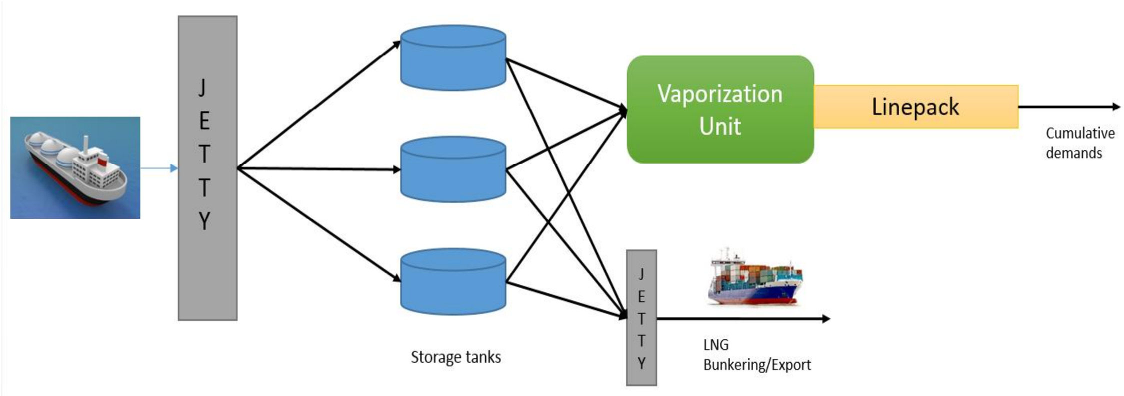

Figure 1: Schematic of operations in a regasification terminal

In this work, we develop optimization model that involves optimal operation of LNG unloading by scheduling of LNG vessels, transfer of LNG from vessel to LNG storage tanks, inventory optimization of storage tanks and optimal operation of vaporizer and send out in natural gas grid. Apart from conventional regasification terminal, terminal also has LNG trading and bunkering facilities. We take into account, the trading of LNG from secondary terminal. There are several decisions involved in these kinds of multi-user, open access import terminal. Shipment Scheduling of incoming and outgoing ships, inventory optimization, demand fulfillment of long and short term contracts and dynamic operational decision for vaporizer has been addressed in the work. MILP Model has been developed for optimizing this downstream side of LNG supply chain.

Acronyms

Index

i – storage tanks

j- vaporizers

Sets

V – Set of incoming vessels

S - Set of Storage tanks

R- Set of Vaporizers

C- Contracts with customers

O- set of orders

Variables

$XF1_{v,t}$ - Binary variable denoting if v starts unloading at time t

$XL1_{v,t}$ - Binary variable denoting if v completes unloading at time t.

$XF2_{v,t}$ - Binary variable denoting if v starts unloading at time t

$XL2_{v,t}$ - Binary variable denoting if v completes unloading at time t.

$XW1_{v,t}$ – Binary variable that denotes if Vessel V is unloading at time t

$XW2_{v,t}$ – Binary variable that denotes if Vessel V is loading at time t

$YR_{r,t}$ - Binary variable that denotes if vaporizer r is operated at time t

$TF1_v$ - Unloading initiation time of vessel v

$TL1_v$ - Unloading completion time of vessel v

$\mathrm{TF2_o}$ - loading initiation time of order o

$\mathrm{TL2_o}$ - loading completion time of order o

$\mathrm{VV_{v,t}}$ – Volume of vessel v at time t.

$\mathrm{VO_{v,t}}$ – Volume of Order O at time t

$\mathrm{FVS_{v,i,tt}}$ – LNG Volumetric flow of from vessel v to tank i at time t.

$\mathrm{FSO_{v,i,tt}}$

$PGas_c$ – Purchased gas by customer C above the contracted amount

$PT_{c,t}$ – Penalty incurred by company for the time interval t

Parameters

$VV0\_v$ - Initial volume of vessel v at time of arrival

$\mathrm{FVS_{v,i,max}}$ – Maximum LNG Volumetric transfer from vessel v to tank i at time t.

$\mathrm{FVS_{v,i,min}}$ – Minimum LNG Volumetric transfer from vessel v to tank i at time t.

$FSO_{o,i,min}$- Minimum LNG Volumetric transfer from tank i to order o at time t.

$FSO_{o,i,max}$- Maximum LNG Volumetric transfer from tank i to order o at time t.

$\mathrm{DD_{c,t}}$ – Demand from customer C at time t

$\mathrm{DC}_{\mathrm{c,total}}$ – Volume of natural gas contracted by customer C

$DD_{o,t}$ – Due date t for order O

$TArr1_v$ – Expected Time of arrival of incoming LNG Vessel

$TArr2_o$- Expected time of arrival of outgoing LNG orders

Scalar

Vf – Volume factor

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CHAPTER 1

INTRODUCTION

The global energy demand is rapidly increasing, and the trends seem to be alarming for global energy crisis in coming future. World energy consumption is estimated to increase from 524 quadrillion Btu in 2010 to 630 quadrillion Btu in 2020 and 820 quadrillion Btu in 2040, an increase of 56% over next 30 years. The unprecedented growth in energy usage is primarily driven by rapid economic growth, and rising population in emerging markets, and their integration into the global economy. The international Energy Agency (IEA) estimates that the developing world will contribute 74% of the increase in energy usage in the reference scenario. The share of China and India alone is expected to be around 45% of the projected increase in the IEA reference scenario. [1]

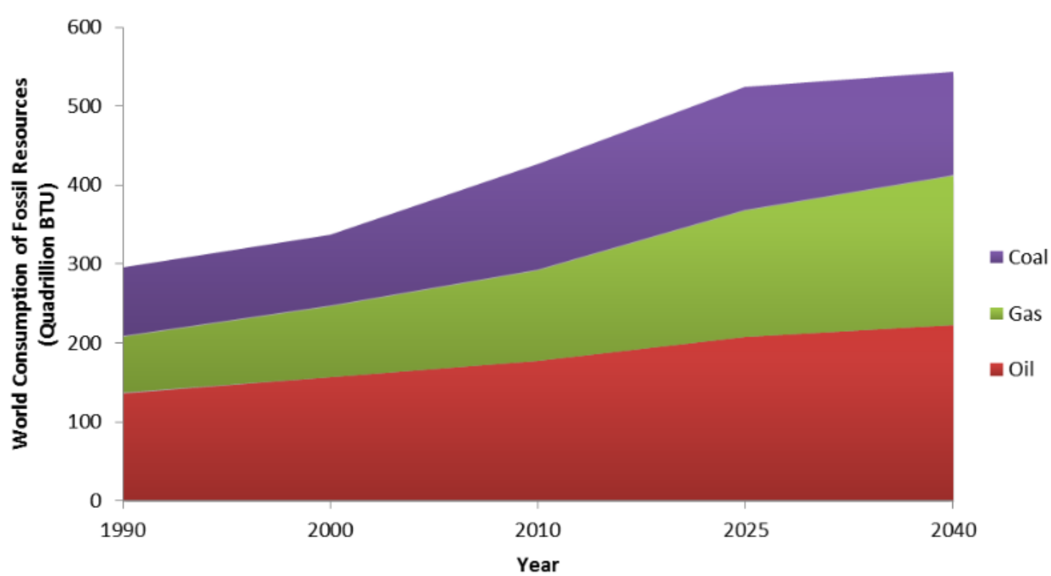

Figure 1.1 World consumption of fossil resources 1990-2040

For the foreseeable future, fossil fuels will continue to form the mainstay of global energy supply. They contributed 81% of global energy demand in 2012. Their share is estimated to almost stay the same at around 82% of the global energy demand in the IEA reference scenario (without any major policy changes) and drop to 76% in the IEA alternative policy scenario (i.e., with government policies to address energy security and climate change) by 2030. Hence, over the next two decades or more, ensuring reliable supplies of fossil fuels will be instrumental for global energy security and therefore for maintaining the high growth rate of the global economy that is crucial for breaking the cycle of poverty in the developing and poor economies. Natural gas is predicted to be the fastest-growing fossil fuel, as global supplies of tight gas, shale gas, and coalbed methane increase.

The industrial sector will account for the largest share of delivered energy consumption and is projected to consume more than half of global delivered energy in 2040. Based on current policies and regulations governing fossil fuel use, global energy-related carbon dioxide emissions are projected to rise to 45 billion metric tons in 2040, a 46% increase from 2010. Economic growth in developing nations, fueled by a continued reliance on fossil fuels, accounts for most of the emissions increases.

1.1 Natural gas

Natural gas is a hydrocarbon gas mixture consisting primarily of methane (CH_4) (usually in the 70-90 mole percentage range)/ It also contains varying amount of other higher alkanes like ethane, propane, butane etc. and even a lesser percentage of carbon dioxide, nitrogen, and hydrogen sulfide world's total natural gas consumption increases by 1.7 percent per year on average, from 113 trillion cubic feet in 2010 to 132 trillion cubic feet in 2020 and 185 trillion cubic feet in 2040. Increasing shale gas production and exploration in United stated, Canada, recently in China and other places, have boosted the global supply market. China shale gas market is expected to come from tight gas, shale gas, and coalbed methane. The recent advancement in hydraulic fracturing, and other drilling technologies have led to rapid increase in natural gas production. As the result of production in several parts of world, the natural gas prices remain below the oil price in energy content basis, and its sustainable growth with new drillings over the years has led to worldwide growth in gas consumption. Natural gas consumption for electricity power generation is expected to increase by nearly 80% from 2010 to 2040. The gas consumption in industrial sector is expected to increase by 60%. The two sector alone will foresee a growth of more 77% over the projected period of 2010-2040 (BP energy market, 2013) [4].

Natural gas demands

Natural gas is greener fuel compared to either oil or coal. It produces lesser carbon emissions, sulphur emissions, particulates or other pollutants. In the time of increasing carbon emission, and global warming scare, natural gas is preferred fossil fuel that can mitigate the environmental risks It is expected to play an important role from transition from conventional fossil fuel to cleaner energy alternatives. Currently, industrial uses and power generation are the major consumers of natural gas Global natural gas demand in 2012 was 3215.9 billion cubic meters (bcm). The global natural gas demand is expected to rise from 2, 3215 bcm in 2013 to 4,779 bcm in 2030 in the IEA 2013 reference scenario, rising at a rate of 2.1% annually.

There are three main uses of natural gas based on the sectors:

1. Residential and commercial users use natural gas for various household purpose from heating houses, water, cooking. It is mainly dependent on weather, and cold countries have been dependent on natural gas for heating from early 20th century. Heating space and water, and cooking. Users have been dependent and captive about their behavior ad therefore, residential demands take time to adjust in face of a price change or a supply shock.

2. Industrial users may use gas as feedstock, or for in-house power generation on a small-scale power generation or as a heating source in industry. Their demand is stable and can be easily forecasted with minimum uncertainty. Industrial users can easily switch to another fuel like diesel oil during the unexpected price increase or demand shortage.

3. Natural gas use for power generation is rising rapidly in the OECD countries with a doubling of gas use for power in the past fifteen years [5]. Combined-cycle gas turbine (CCGT), or Gas-fired power has been used to meets peak summer demand in several countries. There have been several power plants that been established in the local regions of Indonesia, Australia and other natural gas producing countries that been using natural gas. In Europe, almost two-thirds, and in North America, half, of new electricity plants are based on natural gas [5]. These are favored economically viable

because they are highly efficient and require less capital investment. The efficiency of CCGT plants can be as high as 60%, the highest for any thermal power plant.

Increasing global environmental concern, carbon emission and effect on global rise in temperature has favored natural gas fuel for power generation. Combined cycle Gas-fired plants are also being preferred in the United States and Europe because coal-fired generation is being held up by policy uncertainly and high taxes on carbon emissions.

Gas-to-liquids (GTL) is another potentially promising area for exploiting stranded reserves. GTL involves converting natural gas into liquid transportation fuels at source. However.

LNG Value Chain process

Traditionally, natural gas has been transported by pipeline from reservoir to market. As a consequence, major pipeline networks have emerged, especially in Eurasia and North America. Despite the high growth in natural gas market, there is a demographic disparity between countries that produces natural gas and countries that uses it. Also, Natural gas reserve is found to be mainly in stranded locations, giving the rise to longer pipelines network and complex LNG business. For remote areas far away from the market, transportation by ships is often a more cost-efficient solution than transportation by pipelines (Subero et al., 2004). In order to transport the natural gas by ships, it is cooled down to a liquid state. The product is known as liquefied natural gas (LNG). Figure 3 shows the major trade movements of natural gas, and indicates that ships are the primary mode of transportation for long overseas distances. The LNG value-chain comprises of three main segments: the upstream (production, transportation to liquefaction, liquefaction), midstream (LNG sales and shipping) and downstream (LNG regasification, storage and transportation to the market, consumption) segment

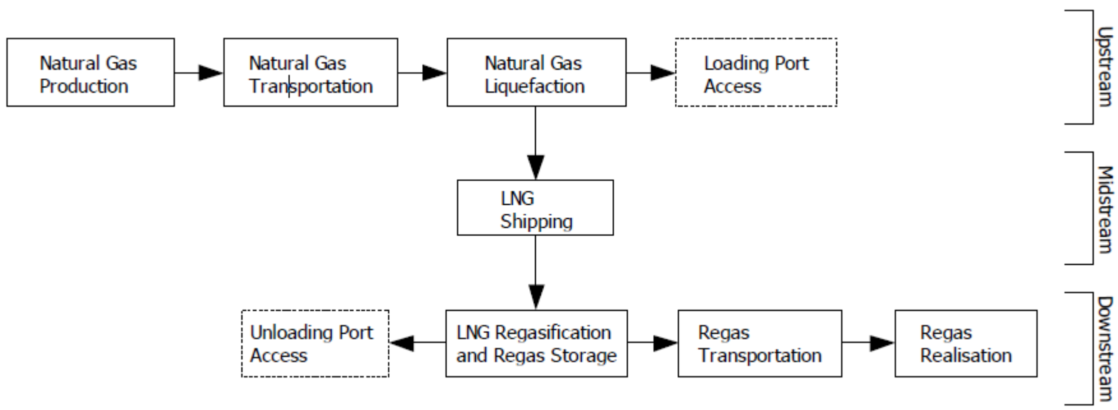

Figure 1.2: LNG Value chain flow

The cost structure indicated in the LNG value chain (Figure 1.2) shows that the substantial or majority of the capital investment is required for cryogenic process of liquefaction of NG. Most of the time the liquefaction process plant is located in the different country, which is the exporting country. The shipping cost if directly proportional to the distance from the market and other complexities such as business environment and contractual agreement. A comparatively smaller capital is needed for the import of LNG through a receiving terminal. These estimates are in line with those of the EIA (2013) that estimates that the production of natural gas represents 16 to 22 percent of the costs, the liquefaction (including the processing, loading, and storage) 28 to 48 percent, the LNG shipping 12 to 32 percent and the receiving (including the storage and distribution) the remaining 15 to 25 percent. The recent market concerns have seen the price rise in LNG market. The general escalation in global energy market, fierce competition for materials and infrastructure, and requires manpower shortage has led to price rise. According to the Center for Energy Economics (2013), the increase in LNG value chain costs between 2008 and 2002 amounted to about 30 percent.

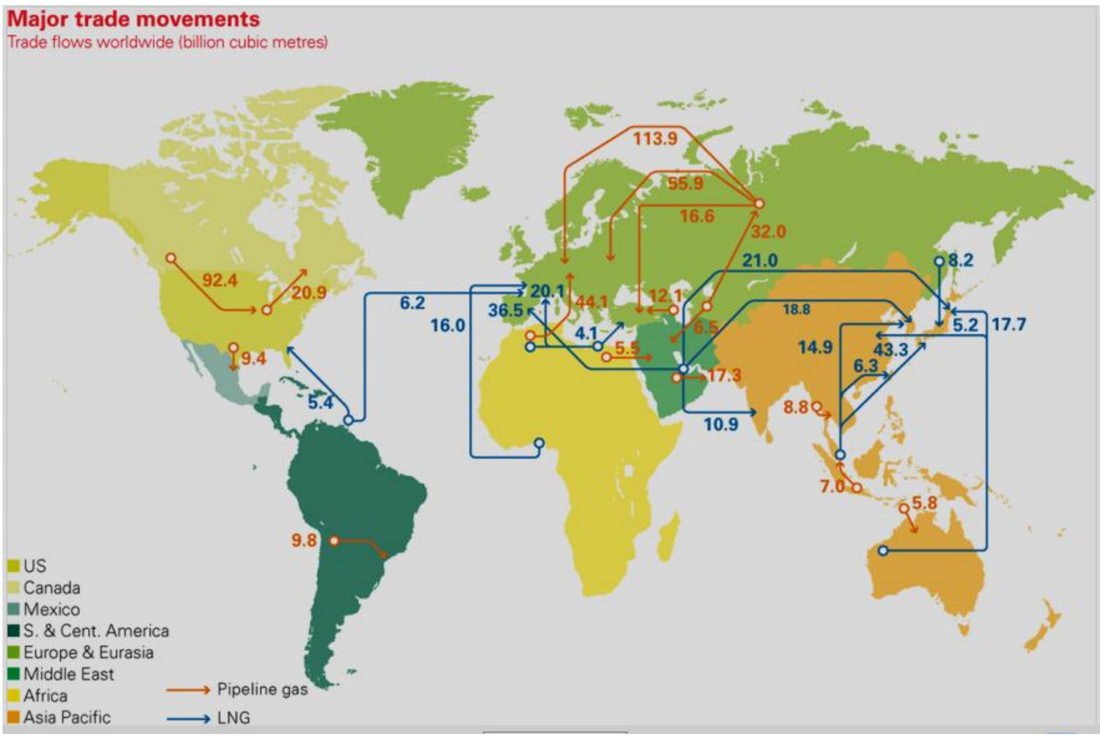

Figure 1.3: major global trade movement, 2011 (BP 2013)

LNG is a cryogenic liquid, with a boiling temperature of ≈ -162◦C at atmospheric pressure. Compared to natural gas, the volume of LNG is reduced by a factor of more than 600. This enables transportation of LNG by specially designed LNG carriers. Conventional carriers' capacity is in the range 130,000 - 150,000 m3 LNG, but the last decade has seen tens of carriers with capacity well above 200,000m By the end of 2011 the global LNG fleet was 363 ships, and additionally 33 in the order books (Wang and Notteboom, 2011) [6] . In comparison, the fleet of active LNG ships numbered 220 only five years ago (Koren and Richardsen). LNG Supply chain is made up of 4 connected segments: exploration/production, liquefaction, transportation and regasification. Each of these segments are independent processes and have larger industry businesses.

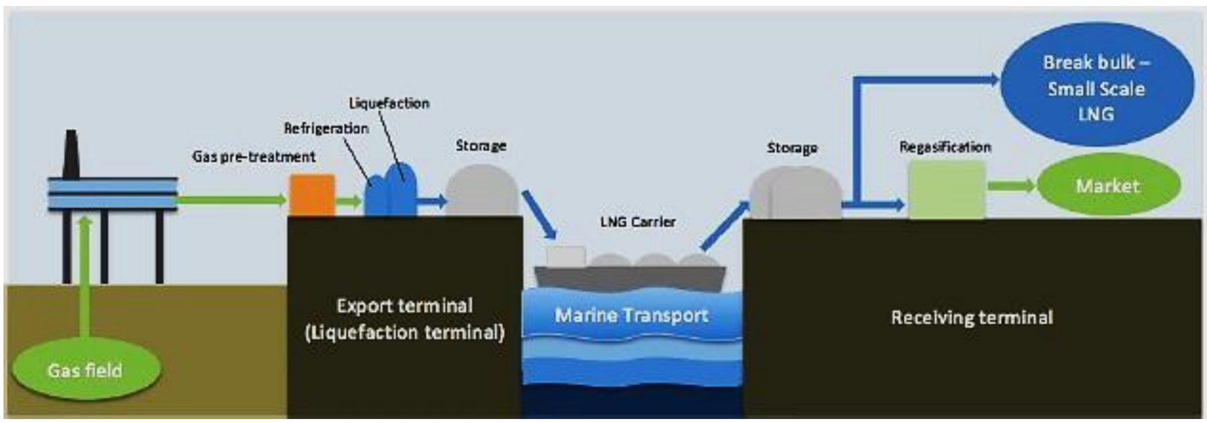

Figure 1.4: LNG Supply Chain overview

1. Exploration – production

At the beginning of the project, geological experts identify the location that may contain natural gas. Then they carry out several tests such as seismic analysis, depth and rock structure analysis as a part of initial assessment. With considerable high probability of discovering gas, dirlling is started, and if viable, the production is started. It nearly takes 3-8 years to start the geological tests to the productions.

2. Liquefaction

The natural gas extracted from the drilling gas and is filtered and purified. The liquefaction process produces a natural gas with a methane content close to 100%. It is also dependent on location, as some region may have lower methane content. Liquefaction plants often consist of several installations arranged in parallel, called “liquefaction trains”. The density of LNG is around 45% that of water.

3. LNG transportation

An LNG carrier is a tank ship designed for transporting liquefied natural gas (LNG). As the LNG market grows rapidly [1] the fleet of LNG carriers continues to experience tremendous growth. Double hulled Liquefied natural gas tankers are designed to prevent any kinds of leakage and rupture or any collateral damage in the wake of an accident. An LNG is stored in the 3-6 per tanker at temperature around -163°C, and at atmospheric pressure. There are three kinds of LNG carriers which are differentiated based on the tank design: IHI Prismatic tanks, Membrane tanks and Spherical tanks. In 2009, carriers with membrane tanks accounted for more than 60% of world LNG transportation capacity, and more than 85% of orders. The LNG tanks can store from 120,000 m^3 up to the latest lager carriers such as capacity carriers such as the Q-flex (210,000 m^3) and Q-max (260,000 m^3) vessels.

Figure 1.5: Interior of a membrane type tank in an LNG carrier (Source: GTT)

4. Storage and regasification

Once received and offloaded, the liquefied natural gas is returned to cryogenic storage tanks – usually varying in capacity from 120,000 to 180,000 cubic meters, depending on the place. It is kept at a temperature of -163°C prior to regasification. Regasification consists of gradually warming the gas back with the heat exchanger, either with sea water or gas fired heat exchanger. It is done under high pressures of 60 to 100 bar, usually in a series of seawater percolation heat exchangers. On its way out of the terminal, the gas undergoes the treatment processes needed to bring its characteristics in line with regulatory and end-user requirements. Its heating value, for example, may be tweaked by altering nitrogen, butane or propane content or blending it with other gases.

Exporting and importing countries

The LNG importing countries can be divided into 2 markets: the Atlantic Basin and the Pacific Basin. The Pacific Basin comprises countries along the Pacific and in South Asia (including India). The Atlantic Basin covers Europe, North and West Africa and the Atlantic coast of the American continent.

The Pacific Basin market emerged in the 1990s, at a time when demand in some Asian countries increased significantly (mainly Japan and South Korea). LNG represented an alternative to oil, and the goal was to maintain security of supply even at relatively high cost. The Atlantic Basin market emerged later in the 1990s, also for reasons of security of supply, but also in anticipation of a fall in some countries' domestic reserves. Japan, with its 26 terminals, remains the world's biggest LNG importer. Japan (93 bcm), South Korea (44 bcm) and Taiwan (15 bcm) together accounted for 51% of global LNG imports in 2010. These countries are 90% dependent on LNG for their gas consumption.

Components of LNG Regasification terminal

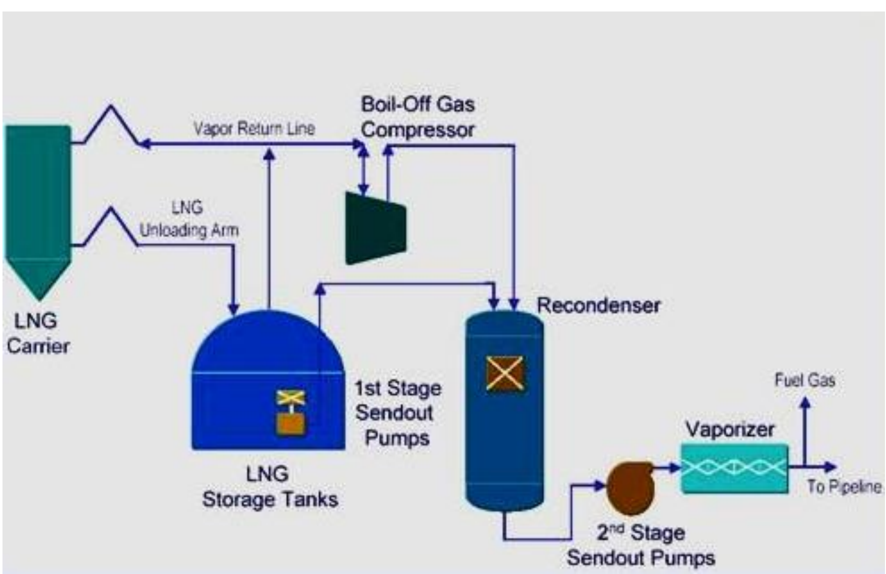

Figure 1.6 Process flow of LNG receiving terminal

The LNG Terminal is a multi-component system which is designed to carry out several tasks simultaneously. At the upper level, the jetty is designed to moor the LNG carrying vessel. The schedule of arrival of ships are known to the schedulers. It is then transferred to the storage tanks which is then send out to the local market and end-users. LNG terminal is designed to deliver regasified at the pressure of the pipeline. The long pipelines which runs several kilometers are generally maintained till 100 barg, and those of the pipelines which runs for around 100-200kms are maintained at 40 barg pressure with temperature around 10-15^{o}C. In order to meet the downstream demand, LNG terminal carries out following main operations.

Receiving

The receiving section consists of the berthing area for LNG carriers, the unloading arms and the transfer line. There can be more than one jetty and berthing area can be located at either of the jetties. Normally main jetty can facilitate the berthing of LNG carriers from capacity of 120,000 m^3 to 265,000 m^3, and secondary jetty can berth order vessel or bunker barges with capacity lower than 120,000 m^3. The jetties are equipped with mooring dolphins and/or breasting dolphins, and each of which are usually equipped with quick release mooring hooks and fenders that protect LNG carriers and give stability while transferring.

The right side of the pier is equipped with 3-4 transfer lines which transfers LNG from vessel to storage tanks, and one centre line which returns the LNG vapor to the LNG carrier. The LNG from the LNG carrier is usually transferred to the storage tanks through 30-60 inch transfer lines that connects the unloading arms to the tanks.

1. **Storage**

The storage tanks are capital intensive structure of the LNG terminal facility. The storage tanks are insulated with double walled section walled tanks build either below ground or above ground. The main capacity can be small around 60,000 m^3 to as large as 250,000 $m^{3.}$ Submerged pumps are installed at the bottom of the tanks that maintains in the movement of the LNG. The tanks are insulated to maintain the temperature of -163 ^oC and pressure just above the atmospheric pressure. The tanks are coaxial cylindrical and made up of 9% nickel and steel. The material stops from corrosion for long term LNG terminal life.

Reloading

The secondary jetty can facilitate incoming of order vessels and bunker barges that can supply the orders and off shore island or bunkering of The LNG Terminal has the capability to reload LNG back onto a LNG carrier that is berthed at any of the three jetties. The transfer lines are the same 40” line that used to discharge the LNG into the tanks. There is one line that maintains pressure using pressure differentials of vapor pressure.

Regasification

The regasification section is responsible for two jobs: regasifying LNG into natural gas, and secondly to maintain pressure according to the exit pressure conditions. It consists of High pressure boosters for movement and pressurizing LNG. Two kinds of vaporizers- Open rack and submerged combustion vaporizers are used to exchange heat with sea water to vaporize the LNG.

Boil-off gas (BOG) recovery

The temperature difference between atmospheric temperature and temperature of the LNG makes the heat transfer through the walls of the tanks. Although insulation prevents the 99.95% of the heat, there is few heat that boils LNG every time. The boil-off gas generated is around 0.05% of the volume of the tank. The generated BOG is a loss, and it is recovered using Boil-off recovery unit. This unit consists of three reciprocating cryogenic compressors, the suction drum and recondenser. The recondenser condenses BOG into LNG and sends back into the storage tanks. BOG recovery unit saves lots of natural gas that were traditionally flared off.

Metering system

Metering station monitors the quantity and quality of the send out gas. The quantity send out is equivalent to real time demand based on the contractual agreement. The quality is specified in the contract and that means methane percentage or caloric value is monitored at the metering station. For example, its calorific value can be adjusted by adjusting the concentrations of nitrogen, butane or propane or by blending. On its way out of the terminal, the gas is treated as necessary to conform to regulatory and end-user specifications. It also add the mercaptons for adding of smell for any kind of detection of leakage for safety of repair.

Chapter 2

Literature Survey

LNG industry has been developing since last few decades and there has been significant advancement in all the segments of supply chain. The interests of several parties, 3PL, government, financers, large corporations etc. has made this multi-billion dollar industry as centre of interest in alternate energy findings. However the supply chain interest of LNG has not been well studied in the literature, and is one of the critical areas to operationally enhance the terminal and downstream operation, and to work under several contracts.

2.1 Natural Gas transportation

There has been substantial work on gas transportation transmission, pipeline network problem. The main objective has been to minimize the CAPEX, OPEX and other relevant costs incurred to the company. An optimal control perspective on the problem is described in Marqués and Morari [32] and Osiadacz and Bell [1]. They discusses about the control optimization and compressor modelling for pipeline. Furey [2] presents a successive quadratic programming (SQP) algorithm for optimizing natural gas pipeline networks and linepack modelling. An optimal routing problem for natural gas transportation is presented in Dahl et al. [3]. A simulation model for natural gas pipeline systems is presented in Nimmanonda et al. [3]. Various numerical and mathematical aspects of cost minimization in gas transmission networks are discussed in [5-8]. Arsegianto et al. [9] present a simulation-based design of a gas transmission network. Kabirian and Hemmati [10] present a nonlinear programming (NLP) model for design of natural gas transmission networks

2.2 Decision-making for local utilities

There has been quite an extensive work in the area of solving the decision support model for making purchases, delivery and storage decisions for local distribution companies (LDC) and gas transportation companies. A decision support system model for natural gas delivery is developed in Chin and Vollmann [11]. It discusses about the optimal delivery to local distributing companies (LDC). Guldmann and Wang [12] solves a model for selecting the optimal mix of natural gas supply contracts for a LDC. Similar contract selection approach for a North American gas producer is presented in Haurie et al. [13]. A LP model for determining utility decisions appears in Avery et al. [14]. A model for a Chilean LDC with contracts is presented in Contesse et al. [15]. It discusses about decision support system that form the delivery strategy for the LDC in Chile. Recently, Gabriel et al. [16] present a mixed nonlinear model of natural gas markets that is solved using global optimization. In another work, the same authors present the problem considering uncertainty and stochastic modelling for natural gas market has been solved [17]. A combined upstream and downstream market model for Europe is presented in Holz et al. [18]. Chen and Baldick [19] discuss a model for optimizing the short-term natural gas supply portfolio for natural gas based power generation for electricity generation usage. Attempts have been made to estimate residential and commercial demand discussion of capacity allocation in pipelines appears in Cremer et al. [20]. A chance constrained approach to making purchasing and storage decisions for a utility is presented in Guldmann [21]. In another work [22] a marginal cost pricing model for the utilities including gas supply, inventory and demands, for gas fuelled Power Company has been discussed. Butler and Dyer [23] develop a multi time period linear programing model for NG purchase by an electricity generating company that considers purchasing, storage and utilization.

2.3 LNG Contracts and pricing

LNG Teisberg and Teisberg [24] discuss a contract valuation methodology for natural gas. An introduction to the application of options theory to oil and gas is discussed in Paddock et al. [25] Weber et al. [26] reviewed and classified 74 papers that had appeared since 1966 with specific attention for Analytical methods used in contracts selections. Dickson [27] was the first paper in the area in 1966. The paper characterizes that the since 1966, there has been increases in the number of papers in the research field but it mainly covers price, quality, location, capacity, but there has been not much attention in the area of quantitative methods of vendor selection, even though the decision-making was becoming more and more complex over time Mohanty and Deshmukh [28] applied the analytic hierarchic process (AHP) to the contract selection problem. They identified four criteria, namely, price, quality, delivery, and service. Weber and Current [29] presented a multi objective optimization approach for multi-criteria trade-off in contracts selections. Vendors commonly relate price to quantity. Chaudhry et al.[30] presented MILP to select vendors who offer price breaks for a single product. Sadrian and Yoon [31] developed a procurement decision support system (PDSS) using MILP.

2.4 Natural gas Linepack Modelling

Many researchers have worked on the gas pipeline and linepack modelling. Abbaspour et al. [32] develop an optimization model for linepack operation of compressor stations and solve it with a sequential unconstrained minimization technique. Marques and Morari [33] presented an optimization model that spans the time horizon from the present to an instant of interest in the future. Osiadacz [34] described used a simple linear diffusion equation to describe the transient flow through the pipe under isothermal conditions. Furey [35] developed an algorithm for dynamic optimal control of complex gas networks. Vostry et al. [36] showed two different long-term and short-term optimizations. The long term strategy depends on steady state conditions, and short term depend on dynamics of the system. Pietsch et al. [37] described a transient optimization that included fuel and energy optimization, evaluation of spot market opportunities, and optimization of facility expansion or addition designs, risk management and presented multi optimization approach for solving the problme. Rachford and Carter [38] presented an algorithm to make operators take decisions in controlling linepack and fuel delivery so as compressors remains in transient conditions. Carter and Rachford [39] explained some control strategies for uncertainty and fluctuations that arises during changing the forecasted delivery or the change of set point of the compressor.

2.5 Planning and Scheduling in Crude Oil refinery

There has been several problem related to planning and scheduling that has been solved and applied in crude oil refinery. The crude oil scheduling is a complex process, and has been well discussed in literature.

Shah [32] considered mathematical optimization techniques for scheduling the crude oil supply to the refinery. The relevant decisions to allocate the crude oil to the various refineries. It also discusses about the connections to different processes such as Crude distillation units (CDUs), blending, and discharging and other components of crude oil supply chain. Brown [33] presented a model for a crude oil tanker scheduling problem. The model considers various cost components of the supply chain such as fleet cost, opportunity cost of ship timings, port and canal charges, demurrages and bunker fuel etc. It also considers the operating speed and optimum loading for the vessel.

Moro and Pinto [34] developed a nonlinear planning model for refinery production that allowed the implementation of nonlinear processes. It also addresses the scheduling problem that relied on both continues and discrete model time formulations.

Jetlund and Karimi [35] worked on efficient routing and scheduling of chemical tankers for improving logistics in global chemical supply chains. They developed They developed a mixed-integer linear programming (MILP) formulation using variable-length slots for a single ship that considers maximum-profit scheduling for a fleet of multi-parcel tankers engaged in shipping liquid bulk chemicals. They used the heuristic decomposition algorithm. Cheng and Karimi [36] devised continuous MILP models for scheduling transhipment operations in chemical transportation for distribution of bulk cargo. They considered the multi compartment service vessel and distribution to multiple refinery in the region. In addition, they also developed intuitive simplified heuristic model.

2.3 Supply Chain management

Investing in LNG is a strategic and cost intensive decision, which involves multi party involvement. This is not surprising given the large risks and costs associated with it. There exist a number of deterministic investment models, such as Sullivan (1988), Haugland et al. [38], Nygreen et al. [37] and van den Heever et al. [39]. There are also some models which incorporate uncertainty, such as J¨ornsten [40], Haugen [41], Jonsbr°aten [42], and Goel and Grossmann [43]. The uncertain parameters in the models include future demand for natural gas, development of oil prices and available reserves in the fields.

Supply chain management has been a research area of increasing focus within the last ten years, see reviews like Manuj and Mentzer [44], Ju¨ ttner [45] and Vanany et al. [46]. Other relevant research include papers on supply chain disruptions (Chopra and ManMohan, [46]; Craighead et al., [47]; Kleindorfer and Saad, [48], supply chain vulnerability (Asbjørnslett, [49]; Peck, [50]; Wagner and Bode, [51]), and supply chain flexibility and resilience (Ponomarov and Holcomb, [52]; Tang and Tomlin, [53]). More practical approaches towards supply chain risk management can be found in the workbook on supply chain risk by Cranfield University (Cranfield, [54]), and in the Supply Chain Council SCOR model on risk management (Morrow et al., [55]).

2.7 Research Focus

Dougherty [56] presents a review of works until 1970 from a petroleum engineering perspective that covers both oil and natural gas applications. Another literature review of the work prior to 1977 can be found in Durrer and Slater [57]. Broadly, the work relevant to natural gas can be divided into the following topics:

1. Planning and scheduling in natural gas systems, both from the supply chain point of view and subsystem perspective.

2. Modelling, simulation and optimization of gas transportation systems.

3. Optimization based Decision support system for local distribution companies (LDC) or power companies for procurement, storage and utilization of natural gas.

4. Development of infrastructure, planning and innovation in both in oil and natural gas fields.

5. Some relevant models for oil and gas fields.

There has been several works in each of these area, but due to larger complexities of business and energy market, there has been cases that involves more macro decisions that involves more than one combinations of the above topics. The main research scope is to solve problem that involves planning and scheduling at terminal, and at the same time it maximizes the opportunity for LDC by optimally delivery it. It also stabilize the system and utilize it at steady state by using it steady state. At the same time contractual agreement makes the model more complex. The approach through this research is to integrate several components of the LNG business and quantitatively model it and take optimal decisions. The work has not been found in literature and this gives enormous opportunity for application.

CHAPTER 3

SCHEDULING OF UNLOADING, INVENTORYAND OPTIMAL DELIVERY OPERATIONS AT LNG REGASIFICATION TERMINAL

3.1 Introduction

The supply chain of LNG industry involves four main sections: natural gas exploration and production, liquefaction, shipping, receiving and distribution. The shift of energy outlook from conventional crude oil to the need of alternate energy demands a more matured supply chain, better managed facilities, optimal utilization of resources and competitive price advantage. Optimism towards natural gas as an alternate energy as its proving to be a fast steady solution to the depleting conventional crude oil reserves and rising prices of crude oil. Environmental friendly natural gas market has been in development phase in last few decades. However, it is changing rapidly with investment in current decade. Liberal gas market which is run by several stringent contracts between different parties to make sure investment is feasible over the long time horizon and investment and operational risk is distributed over all the stakeholders.

LNG terminal is key link between producers and downstream end-users (power plants, residential users etc.). The terminal is one of the most expensive unit in the energy business and it is important to manage the terminal with optimized manner, to maximize the profit. The long term and short term project of the terminal owner should take into account several supply and demand projections, price fluctuations, uncertainties in demand and supply. In the short-term, capacity and operation of the natural gas networks and the flexibility of gas markets affect the vulnerability of the gas system to demand peaks and supply interruptions. Transportation constraints prevent trade and arbitrage and reduce the efficiency of terminal usage, and increases the demurrages. The demand side limited by the ability of pipeline operators to efficiently allocate transportation capacity. When these inflexibilities and constraints are not alleviated, supply costs and uncertainty increase, which slow supply and demand growth. (IEA, 2011). The terminal can facilitates the multi-user to store and regasify, and it can be accessed by multiple customers at the same time. The terminal operation requires to abide by the contracts, and at the same time use the units within operation limits. The scheduling model is required at the terminal for the optimal use of the facility, and maximizing the output and minimizing the penalties.

3.1 Problem Statement

An entity owns and manages a multi-user LNG import terminal which imports LNG from different producers by LNG carriers, unload LNG into storage tanks, and send out the demand over given time. LNG and gas trading. The regasified natural gas is used for industrial and power generation based on long-term and short term contracts. In addition to the core business of throughput services, the company also offers other services such as LNG storage and reloading services. Here, company provides unloading, reloading, and temporary storage services to other companies based on their prior agreements. Also, it facilitates bunkering services to provide fuel for ships using LNG as a fuel.

The configuration of this system corresponds to a multistage supply chain network. It mainly consists of LNG Vessels, storage tanks, vaporizer, and secondary jetty for bunkering and distribution centers for meeting industrial demands. All these components resemble different nodes in a supply chain and are related to each other as shown in Figure 1. The demands from different customers are usually tied with long term or short term contracts and are known a priori.

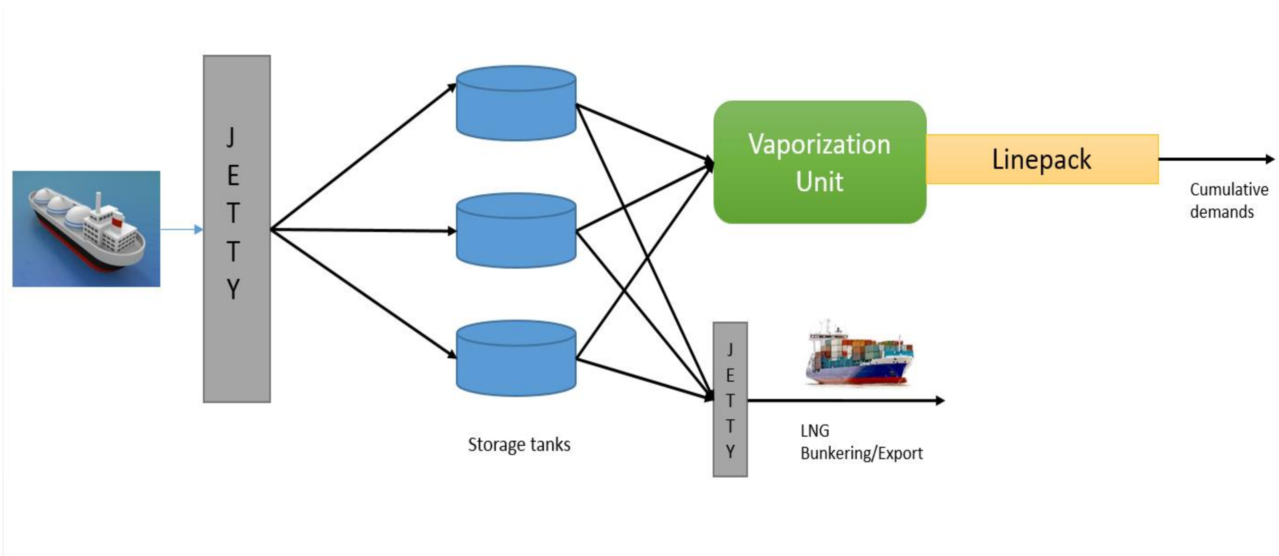

Figure 3.1: Schematic of operations in a regasification terminal

Figure 3.1 shows the schematic of an LNG supply chain surrounding an LNG regasification terminal. In addition to this terminal, it shows a nearby LNG bunkering terminal and several local grids or distribution systems for natural gas (NG). The former supplies LNG as a marine fuel to dual-fuel or LNG-fueled ships and the latter supplies NG to a variety of domestic and industrial customers. A business entity manages the operations at the regasification terminal in the context of this supply chain.

The system configuration of the LNG import terminal company is illustrated in figure 1. It is a multistage system consists of LNG vessels, Storage tanks, Vaporizers, send out unit, Primary jetty for receiving incoming LNG vessels and secondary jetty for outgoing LNG orders.

The terminal has J jetties (j=1,2,…,J). Inbound vessels (e.g. LNG tankers) berth here and unload their LNG cargos into the storage tanks. Outbound vessels (e.g. small tankers or delivery ships) also berth here to load LNG cargos from the storage tanks. Each vessel requires some preparation time (for testing, docking, connecting, loading arm cooling, etc.), before LNG transfer can begin. Similarly, it requires some release time after the transfer, before another vessel can enter the same jetty to prepare for a transfer. The business entity must schedule shipments of LNG cargos from its suppliers to maintain inventory at the terminal. It must decide the timings and sizes of these shipments. It must also ensure that both inbound and outbound cargos are transferred as quickly as possible so as not to incur demurrages. Similarly, it must ensure enough ullage in the storage tanks to unload incoming cargos and enough inventory to load outgoing cargos.

The regasification unit at the terminal operates continuously to gasify LNG into NG. To ensure its smooth operation, it is desirable to maintain the regasification rate s steady as possible. The terminal has special take-or-pay (TOP) contracts (described later) with C customers (c=1,2,…,C) of its NG. It supplies NG to G distribution grids (g=1,2,…,G). Each grid g has a dedicated set C_g of customers (c∈C_g). Each customer withdraws gas from its own grid freely as per its needs. In other words, the terminal has little control over the gas that a customer withdraws at any time except for the terms and conditions in its TOP contracts. A typical TOP contract carries several penalties for violating its terms and conditions. While they may vary from place to place, a typical TOP contract stipulates some limits (lower and upper) on the gas uptakes by a customer over fixed intervals (called makeup time). It guarantees the minimum agreed supply to the customer, failing which the terminal must pay penalty to the customer, but also expects the customer to control its gas uptake within the agreed limits. As long as this happens, no penalty is incurred, and the customer pays a normal price for the gas. If the customer uptakes less than its minimum quota within its makeup time, then it loses rights to that quota, and must pay for the shortfall. If the customer withdraws more than the agreed maximum quota, then it must pay a premium price for the extra gas above the quota. In other words, it is the responsibility of the customer to regulate and manage its gas uptakes over time to minimize the various penalties.

In spite of the checks and balances against out-of-limit gas uptakes by the customers, over-the-limit withdrawals do occur. If not regulated, these may jeopardize the supplies to other customers. Therefore, a customer wanting to uptake over-the-limit must seek prior permission or allocation from the terminal. The terminal usually processes such requests individually and grants appropriate allocations. In other words, a customer periodically submits its planned uptake profile to the terminal, and the terminal then decides how much gas to allocate to that customer at various times. Clearly, it is likely that the terminal may agree to only a part of the high demand requested by a customer. In such cases, the customer is contractually bound to not exceed its allocation, otherwise it may pay significant penalty. Needless to say that the gas allocation decisions by the terminal require a global view of the overall operation and demands. To the best of our knowledge, this is currently done manually in the industry by dedicated experts. A scheduling tool such as the one presented in this work can be very useful in aiding and improving the gas allocation decisions by the terminal.

The inventory of NG in the transfer lines of a distribution grid offers an interesting option for temporary storage because of its compressible nature. The terminal can avail the freedom of varying the gas pressure in a grid over time. By increasing the pressure, the terminal can hold more gas in the grid. Thus, it can use the grid for temporary NG storage to act as a buffer against uncertain and peak demands. This would also allow the terminal to minimize fluctuations in its regasification rate. This concept of using the distribution system for temporary storage is known as linepack (give references) in the gas industry.

Apart from selling NG, the terminal also sells LNG in two ways. First, it ships relatively small LNG cargos to regional customers via small tankers or delivery ships. These outbound delivery ships compete with the large inbound tankers for jetties. Second, the terminal also supplies LNG as a marine fuel to the nearby LNG bunkering terminal. This supply is via trucks and/or pipelines, and hence needs no jetties. Both these trades (bunkering and regional distribution) are nascent and relatively tiny markets at this time in the LNG industry. Since the bunkering calls will be sporadic and unpredictable, the goal will be to merely maintain LNG inventory in a supply tank at the bunkering terminal. For this reason, we treat this demand as continuous. However, we do impose a penalty (opportunity cost) for not supplying the demand requested by the bunkering terminal. Similarly, we also impose penalties, if a delivery ship is delayed in its departure from the terminal or could not get the required amount of cargo.

Hence, the regasification terminal has one or more jetties, several LNG storage tanks, and a regasification unit or vaporizer. It performs the following tasks.

(1) It receives LNG shipments from various sources via large LNG tankers.

(2) It stores LNG in its inter-connected storage tanks.

(3) It sends LNG shipments to its regional customers via small tankers or delivery ships.

(4) It supplies LNG to the LNG bunkering terminal via trucks or pipeline.

(5) It regasifies most of its LNG into natural gas (NG).

(6) It supplies the NG to several end users via the NG grid or distribution system.

Of these, operations 1 and 3 occur intermittently over time, while the others occur largely continuously.

We address the scheduling of LNG terminal operation for a given horizon [0,H], during which several LNG carriers are to arrive at the terminal and terminal to fulfil the demands from the refineries and order from the order parcels.

Given:

1. Primary and secondary jetty for unloading and reloading operation, loading and unloading cost at the jetty

2. V ships, their capacity, arrival time and cost of unloading, cost of waiting outside the jetty.
3. S storage tanks, their capacity, minimum and maximum operational limit, operational cost, boil off losses.
4. K regasification units, rate of regasification, operational cost and output volume of natural gas
5. R Storage capacity of Linepack, its upper and lower limits.
6. C customers, who has demand daily and overall demand limit.
7. Daily demand D_{Ct} and the overall demandTD_C.

Determine:

1. Parcels that each tank will receive, start/end times and volume of each parcel transfer.
2. Completion time windows of orders.
3. Actual departure times of incoming LNG incoming vessels and LNG outgoing parcels and any demurrage charges.
4. Completion delay penalties on refinery orders and demurrage charges on incoming
5. Hold up in each tank and volume profile in linepack.
6. Delivery profiles of natural gas to customers at send out.

Assumption:

1. At most one LNG carriers/LNG outgoing parcel can dock at the terminal at any time.
2. Tank can receive and deliver simultaneously.
3. Unloading sequence is known a priori for each LNG incoming vessel and order orders.
4. At most one tank can receive LNG at a time, and one tank can be send out.
5. The daily demands from the customers are known.
6. No roll-over is considered in the storage tanks, and the rate of boil-off will remain constant.
7. Each order must be served fully in the scheduling horizon.

Allowing:

Terminal can receive and deliver LNG simultaneously.

The problem is then to maximize the profit by minimizing the operating variables to minimize the cost. The cost can be minimized by taking some optimal decisions: The scheduling objective is to minimize the total operating costs that include the holding, demurrages, and order delay penalties.

3.3 Model Formulation

We discretize the time into several uniform intervals and assume that the process remains same between the two intervals. It changes only during start and end of the interval.

Let v ∈ V denotes the set of incoming vessels, o ∈ O be the set of order parcel, expected time of arrival of which is known. Let s ∈ S denoted the set of storage tanks. The capacity and operational limits of the storage tanks are known. Regasification unit consists of numbers of vaporizers and r ∈ R denotes the set of the vaporizers in the regasification unit. There is one send out unit which supplies regasified natural gas to the pipeline distribution channel. The pipeline distribution acts as storage depending upon change in pressure. When the pipeline is stored at higher pressure, it can hold more gas. When the demand is more, it can be operated at lower pressure and send out more gases. The linepack acts as temporary storage. The supply of natural gas is bounded by contracts. The supply to customer is bounded by contracts Set c ∈ C is the set of contracts which the customers to receive regasified natural gas.

Let v be the set of the vessels (v = v1, v2, …, V) coming at primary jetty. The time of arrival AT_v is known. If the jetty is occupied, ship waits till the previous ship leaves the jetty. Once the ship arrives at the docking station, the transfer of LNG from ship to storage tanks S (S= s1, s2, ..., S). The transfer starts at time TF_v and unloads the entire volume of the ship. The unloading operation finishes at TL_v. The ship can transfer at only one storage tank at a time. The volume of the storage tanks at the given time t is Q_{st}. The volume of the storage tank has minimum and maximum upper limit. The terminal also facilitates the export of the LNG from the secondary jetty. The order parcel arrival time is known in priori. Apart from unloading operation and loading at secondary jetty, the terminal has the regasification and send out unit. The gas supply is bounded by the long term contracts with the daily upper and lower limit. The natural gas customer, mainly power plants, also has the contract over the total volume of the gas delivered over the scheduled time. However, customer are free to demand more than the contracted amount. Penalty is imposed if the customer demands are not met.

3.3.1 Unloading Operations at Primary Jetty

The unloading of LNG is important process as it requires We divide the planning horizon $[0, H]$ into T uniform intervals ($t = 1, 2, \ldots, T$). Unless specified otherwise, the constraints are written for all valid values of their defining indices.

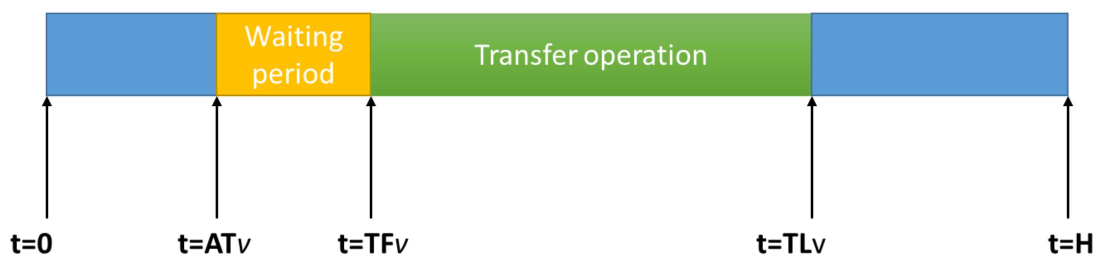

Figure 3.22: Timeline of unloading operation

Let vessel v reach the terminal at the start of interval ETA_v and be expected to leave the latest by the end of interval LDT_v. Let CV_v be the amount of cargo that vessel v needs to unload and F_v^U denote the maximum amount of cargo that vessel v can unload in one interval. Then, to model the unloading of cargos from LNG vessels at the primary jetty, we define the following binary variables for $ETA_v \leq t \leq LTD_v$.

$$xe_{vt} = \begin{cases} 1 & if\ vessel\ v\ enters\ the\ jetty\ at\ the\ start\ of\ interval\ t \\ 0 & otherwise \end{cases}$$

$$xl_{vt} = \begin{cases} 1 & if\ vessel\ v\ leaves\ the\ jetty\ at\ the\ end\ of\ interval\ t \\ 0 & otherwise \end{cases}$$

$$x_{vt} = \begin{cases} 1 & if\ vessel\ v\ is\ at\ the\ jetty\ during\ interval\ t \\ 0 & otherwise \end{cases}$$

Each vessel visits the jetty only once during the entire horizon. Therefore,

$$\sum_{t=ETA_v}^{t=LTD_v} xe_{vt} = 1 \qquad (3.1)$$

And each vessel leaves the jetty only once during the time horizon,

$$\sum_{t=ETA_v}^{t=LTD_v} xl_{vt} = 1 \qquad (3.2)$$

Since we know the expected ship arrival time, we can initialize the value of binary variable at known time ETA_v

$$x_{vt} = xe_{vt} \qquad t = ETA_v \qquad (3.3)$$

$$x_{vt} = x_{v(t-1)} + xe_{vt} - xl_{v(t-1)} \qquad ETA_v + 1 \leq t \leq LTD_v \qquad (3.4)$$

Since the primary jetty allows only one vessel to unload at a time, a vessel v must finish unloading before $(v + 1)$ can begin.

$$\sum_{t=ETA_{(v+1)}}^{t=LTD_{(v+1)}} (t-1) \times xe_{(v+1)t} \geq \sum_{t=ETA_v}^{t=LTD_v} t \times xl_{vt} \qquad 1 \leq v < V \qquad (3.5)$$

It can be shown that x_{vt} can be treated as 0-1 continuous variable. Each vessel must stay connected to the jetty for sufficient time to unload its cargo. Therefore,

$$\sum_{t=ETA_v}^{t=LTD_v} x_{vt} \geq CV_v / F_v^U \qquad (3.6)$$

While we allow a vessel to unload its cargo into more than one tank, we restrict its transfers to at most one tank during one interval. We define the following binary variable to allow the vessel to transfer LNG into tank s during interval t.

$$xt_{vst} = \begin{cases} 1 & if\ vessel\ v\ transfers\ to\ tank\ s\ during\ interval\ t \\ 0 & otherwise \end{cases} \tag{3.7}$$

If the vessel is not at the jetty, then it cannot transfer to any tank, hence,

$$x_{vt} \geq \sum_{s=1}^{S} xt_{vst} \tag{3.8}$$

Let F_{vst} denote the amount of LNG that vessel v transfers to tank s during interval t. Since this cannot exceed the maximum possible transfer amount, and the entire cargo must be unloaded during the vessel's stay at the jetty, we have,

$$F_{vst} \leq F_v^U xt_{vst} \tag{3.9}$$

$$\sum_{s=1}^{S} \sum_{t=ETA_v}^{t=LTD_v} F_{vst} = CV_v \tag{3.10}$$

Let TT_v denote the maximum number of intervals that vessel v can stay at the terminal without incurring any demurrage. Then, the demurrage can be computed using the following.

$$DM_v \geq 1 + \sum_{t=ETA_v}^{t=LTD_v} t \times xl_{vt} - ETA_v - TT_v \tag{3.11}$$

Demurrages are the penalties that are incurred by the terminal operating company, and have to minimize. Hence demurrages will be included in the penalty function.

Loading Operations at Secondary Jetty

The constraints for order loading will be very similar to those for cargo unloading. Let the earliest interval at which the loading of order o can begin be $\mathrm{ETL_o}$ and the latest interval by which it should finish be $\mathrm{LTL_o}$. Let $\mathrm{OV_o}$ be the amount of order o and $\mathrm{G_s^U}$ denote the maximum amount of LNG that tank s can unload in one interval. Then, to model the loading of orders at the secondary jetty, we define the following binary variables for $\mathrm{ETL_o} \leq \mathrm{t} \leq \mathrm{LTL_o}$.

$$\mathrm{ye_{ot}} = \begin{cases} 1 & \text{if order o begins loading at the start of interval t} \\ 0 & \text{otherwise} \end{cases} \quad (3.12)$$

$$\mathrm{yl_{ot}} = \begin{cases} 1 & \text{if order o ends loading at the end of interval t} \\ 0 & \text{otherwise} \end{cases} \quad (3.13)$$

$$\mathrm{y_{ot}} = \begin{cases} 1 & \text{if order o is at the jetty during interval t}(\\ 0 & \text{otherwise} \end{cases} \quad (3.14)$$

Each order must be loaded only once during the entire horizon. Therefore,

$$\sum_{\mathrm{t=ETL_o}}^{\mathrm{t=LTL_o}} \mathrm{ye_{ot}} = 1 \quad (3.15)$$

$$\sum_{\mathrm{t=ETL_o}}^{\mathrm{t=LTL_o}} \mathrm{yl_{ot}} = 1 \quad (3.16)$$

$$\mathrm{y_{ot}} = \mathrm{ye_{ot}} \quad \text{at } \mathrm{t} = \mathrm{ETL_o}$$

$$\mathrm{y_{ot}} = \mathrm{y_{o(t-1)}} + \mathrm{ye_{ot}} - \mathrm{yl_{o(t-1)}} \quad \text{for } \mathrm{ETL_o} + 1 \leq \mathrm{t} \leq \mathrm{LTL_o} \quad (3.17)$$

Since the secondary jetty allows the loading of only one order at a time, an order o must finish unloading before $(\mathrm{o}+1)$ can begin.

$$\sum_{\mathrm{t=ETL_{(o+1)}}}^{\mathrm{t=LTL_{(o+1)}}} (\mathrm{t}-1) \times \mathrm{ye_{(o+1)t}} \geq \sum_{\mathrm{t=ETL_o}}^{\mathrm{t=LTL_o}} \mathrm{t} \times \mathrm{yl_{ot}} \quad \text{for } 1 \leq \mathrm{o} < \mathrm{O} \quad (3.18)$$

It can be shown that y_{ot} can be treated as 0-1 continuous variable. Each vessel must stay connected to the jetty for sufficient time to unload its cargo. Therefore,

$$\sum_{t=ETA_v}^{t=LTD_v} y_{ot} \geq OV_o / \max_{\mathrm{s}} G_s^U \quad (3.19)$$

While we allow an order to be filled from multiple tanks, we allow at most one tank to fill an order during an interval. We define the following binary variable to allow the vessel to transfer LNG into tank s during interval t.

$$yt_{sot} = \begin{cases} 1 & if\ tank\ s\ is\ loading\ order\ o\ during\ interval\ t \\ 0 & otherwise \end{cases} \tag{3.20}$$

If the order is not under loading, then no tank can load the order, hence,

$$y_{ot} \geq \sum_{s=1}^{S} yt_{sot}; \tag{3.21}$$

Let G_{sot} denote the amount of order o that tank s loads during interval t. Since this cannot exceed the maximum possible transfer amount, and the entire order must be loaded in one shot, we have,

$$G_{sot} \leq G_s^U yt_{sot} \tag{3.22}$$

$$\sum_{s=1}^{S} \sum_{t=ETL_o}^{t=LTL_o} G_{sot} = OV_o \tag{3.23}$$

Let OT_o denote the latest interval by which order o must be filled without incurring a delay penalty. Then, the delay in fulfilling an order can be computed using the following.

$$OD_o \geq \sum_{t=ETL_o}^{t=LTL_o} t \times yl_{ot} - OT_o \tag{3.24}$$

The order must be fulfilled within the contracted number of days, beyond which the penalties are incurred on the terminal operating company. Hence it will be in objective function.

Boil off gas

Due to its cryogenic nature, LNG is continuously vaporized and lost as boil-off gas (BOG) during storage and transportation. The amount of BOG depends on the design and operating conditions of the LNG tanks and ships. Depending on the insulation and sea conditions, a boil-off rate of about 0.1-0.15%. In this work the boil off is assumed to be 0.1% of the volume of storage tank. During loading and unloading operation, the generated boil off gas is more, and is assumed to be 0.15% of the capacity of LNG vessel and outgoing parcel.

$$\mathrm{BOG_t} = 0.001 * \sum_{s} \mathrm{Q0_s} + \sum_{s}\sum_{o} 0.0015 * \mathrm{yt_{sot}} * \mathrm{OV_o}$$
$$+ \textstyle\sum_s \sum_v 0.0015 * \mathrm{xt_{vst}} * \mathrm{CV_v} \qquad (3.25)$$

The boil off gas is sent out into the pipeline.

Contractual Gas Demands

Customers like electricity generating companies must purchase from the producers, regardless of the end customer demand. This quantity is the so-called take-or-pay (TOP), which is a fixed volume of gas contracted with each producer. The total purchase cost is the sum of the fixed TOP cost plus the cost of any additional gas beyond the TOP level, valued at some fixed commodity rate, i.e., a cost proportional to the volume of gas requested. In addition, there are some purchase penalty costs (fines) when daily minimum and maximum purchase levels are not respected.

Another important condition specified in the contracts between supplier and customer is the make-up recourse. Make-up is the difference between the TOP level and the volume of gas actually received by the buyer, when it is below this level, as shown in figure. This make-up may be used, or recovered, when the volume actually received by the buyer exceeds the TOP level, within the agreed periods immediately following the period where it originated. After that, the buyer loses it. In our problem we consider the planning horizon as the time period for make-up recourse.

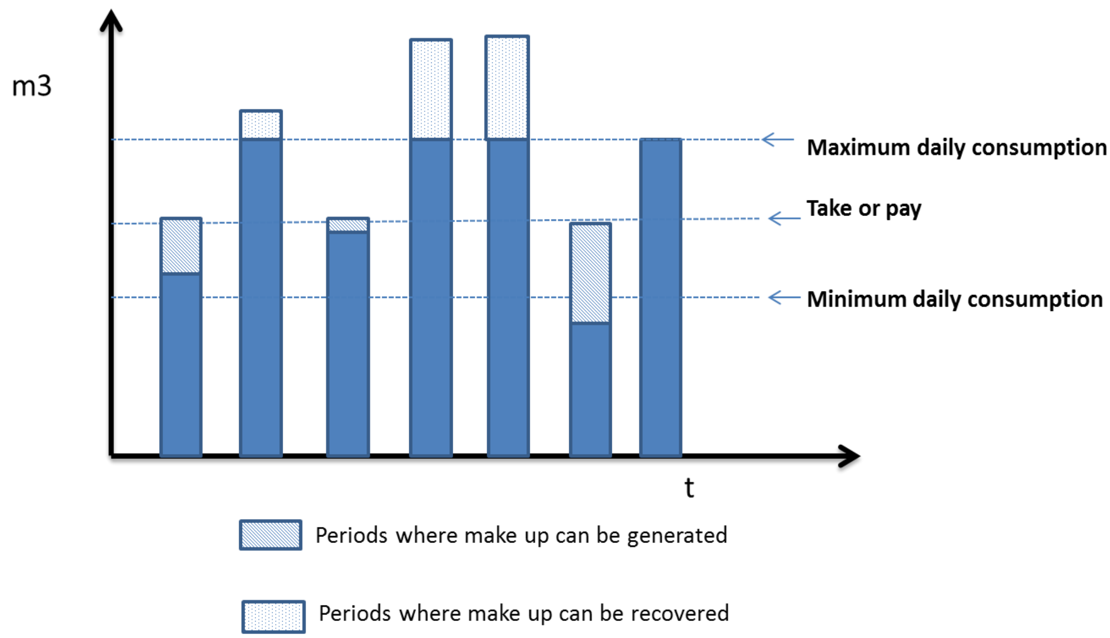

Figure 3.3: make up generation and recovery

To model the contractual problem, we consider the customer agreement for every period and for entire planning horizon.

If $[D_{ct}^{L}, D_{ct}^{U}]$ denotes the range gas volume that terminal has agreed to supply to customer c during interval t, and D_{ct} be the actual demand from customer c, then

$$FG_{ct} = FG_{ct}^{-} + FG_{ct}^{0} + FG_{ct}^{+} \tag{3.26}$$

$$w_{ct}^{-} = \begin{cases} 1 & if\ FG_{ct} \leq D_{ct}^{L} \\ 0 & otherwise \end{cases} \tag{3.27}$$

$$w_{ct}^{0} = \begin{cases} 1 & if\ D_{ct}^{L} \leq FG_{ct} \leq D_{ct}^{U} \\ 0 & otherwise \end{cases} \tag{3.28}$$

$$w_{ct}^{+} = \begin{cases} 1 & if\ FG_{ct} \geq D_{ct}^{U} \\ 0 & otherwise \end{cases} \quad (3.29)$$

$$w_{ct}^{-} + w_{ct}^{0} + w_{ct}^{+} = 1 \quad (3.30)$$

$$FG_{ct}^{-} \leq D_{ct}^{L} \quad (3.31)$$

$$FG_{ct}^{0} \leq D_{ct}^{U} - D_{ct}^{L} \quad (3.32)$$

$$FG_{ct}^{+} \leq max[0, D_{ct} - D_{ct}^{U}] \quad (3.32)$$

$$FG_{ct}^{0} \leq (1 - w_{ct}^{-})(D_{ct}^{U} - D_{ct}^{L}) \quad (3.34)$$

Figure 3.4: Daily contractual limit of customers

$$FG_{ct}^{+} \leq (1 - w_{ct}^{-})\max[0, D_{ct} - D_{ct}^{U}] \quad (3.35)$$

$$FG_{ct}^{-} \geq (w_{ct}^{0} + w_{ct}^{+})D_{ct}^{L} \quad (3.36)$$

$$FG_{ct}^{0} \geq w_{ct}^{+}(D_{ct}^{U} - D_{ct}^{L}) \quad (3.37)$$

$$FG_{ct}^{+} \leq (1 - w_{ct}^{0})\max[0, D_{ct} - D_{ct}^{U}] \quad (3.38)$$

$$D_{ct}^{-} \geq D_{ct} - FG_{ct} \tag{3.39}$$

$$FG_{ct} \leq D_{ct} \tag{3.40}$$

Price of LNG

Unlike crude oil prices, price of LNG is not fixed, and are influenced by regional supply and demand. For example price LNG price in Japan is higher than LNG price in Japan, and so on. Thus price is very critical consideration for LNG buyer and supplier. There have been many formulations to explain the local price. The most widely used pricing structure has been a linear function of crude oil price:

$$\mathrm{P_c = a_c * P_{crudeoil} + b_c} \tag{3.41}$$

where contractual price of LNG is the linear function of the price of crude oil.

The other terms of the contract such as INCO terms and LNG quality is assumed to be same for all customers.

Linepack

The linepack is the fraction of the pipeline's total transportation capacity that is owned by the customer. Any positive or negative linepack unbalances produced by the daily transported quantities with respect to the contracted linepack, are penalized with increasing return to scale costs. Linepack is important reliability on the demand and supply uncertainty. It also guarantee the part of the pipeline to be owned by customer which can used with flexibility.

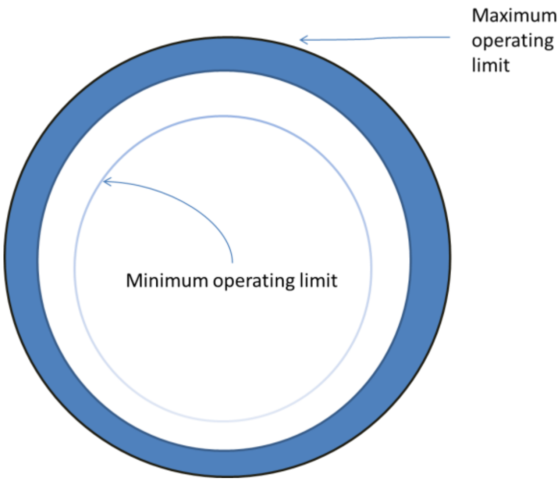

Figure 3.5: Pipeline linepack limits.

Let GG_{ct} be the amount of gas supplied to customer c and RG_{st} be the amount of LNG regasified from tank s during interval t. Let the Then,

$$LP_t = LP_{t-1} + \sum_{s=1}^{S} RG_{st} - \sum_{c=1}^{C} FG_{ct} \tag{3.42}$$

$$LP_t^L \leq LP_t \leq LP_t^U \tag{3.43}$$

There is upper and lower limit to the linepack flexibility and is fixed.

LNG Inventory (storage tanks)

Let Q_{st} be the amount of LNG in tank s at the end of interval t. Then, the mass balance on tank s gives us,

$$Q_{st} = Q_{s(t-1)} + \sum_{v=1}^{V} F_{vst} - \sum_{o=1}^{O} G_{sot} - RG_{st} - 0.001 * Q0_s \tag{3.44}$$

$$Q_{st}^L \leq Q_{st} \leq Q_{st}^U \tag{3.45}$$

There is a constant boil off in the storage tank, and is considered to be 0.1% of the volume of storage tank. Apart from this, there is a minimum volume of LNG that must be required as a part of heel to keep the storage cool. And there is a maximum volume of LNG than can be stored in the tank.

Objective Function

The goal of the terminal is to maximize its revenue.

$$\sum_{c=1}^{C}\sum_{t=1}^{T} FG_{ct}\, P_c + \sum_{t=1}^{T}\gamma_c^{+} FG_{ct}^{+} + \sum_{t=1}^{T}\gamma_c^{-}(D_{ct}^{L} - FG_{ct}^{-}) + \sum_c \beta_c^{-} TG_c^{-} - \sum_{t=1}^{T} \propto_c^{-} D_{ct}^{-} - \sum_{v=1}^{V} DM_v PD_v - \sum_{o=1}^{O} OD_o PO_o \quad (3.45)$$

The scheduling model minimizes the cost incurred during the given time horizon, while maximizing the spot price opportunity.

CONCLUSION AND FUTURE WORKS

From the results of Chapter 3, we can draw the following significant conclusions with regard to the LNG supply chain process at regasification terminal.

1. The understanding of holistic approach at LNG terminal and the understand of stakeholders
2. The scheduling of incoming vessel, unloading and loading of LNG into storage tanks
3. Optimal scheduling of LNG outgoing parcel
4. Regasification decision for the terminal
5. Linepack and use of Linepack for the changing demand and supply.
6. Managing Long and short term contract at regasification terminal
7. Optimal delivery to maximize the profit
8. Supply Chain disruption and mitigating the risk of capital loss using Linepack natural gas

MILP model gives the easy and faster solution (8.42 seconds) that can be applicable as decision support system at LNG regasification terminal. The decision at terminal can be complex as there are several decision involved at a given time. The model based strategic decision is a novel work that has not been discussed in the literature so far. The work extended the boundary of research by working on holistic design that involves several areas of supply chain of LNG at terminal.

The work is based on few assumption and in future it would be even more practical to relax those assumption. However that will make the modeling more difficult and to find the optimal decision parameter can be even more challenging. Few of the area of recommendations can be:

1. The different grades of LNG should be considered in the future. This will make the component non-linear and pricing/contracts limitations. There could also be mixing of different LNG and the safety and risk should be included for the roll over.
2. The assumption that ship arrival time is deterministic is not very practical. The uncertainty consideration and modeling using stochastic or robust optimization problem can help the optimal decision even during uncertainties.
3. Boil off handling includes the reliquefaction, and the reliquefaction thermodynamic cycle can be include in the model. The solution can be found using rigorous simulation model.
4. The consideration of processes of various units and its design parameter can give us global optimization. However such problems are not easy to model and solve. The statistical model using surface response modeling can be tried to achieve the global optimization.

Future works

The current work only touches a part of the larger complex LNG business, and there can be several future works in the area.

1. **Global Optimization**: The work discussed here considers that arrival time of vessel and order vessel as known parameter. However, the upstream market dynamics has not been considered in the model. Also, for the downstream power generation demand model can be included for better practical modelling of the system
2. **Uncertainty modeling**: Uncertainty arises from various conditions have not been modeled. The stochastic or robust optimization modeling can be used to model the various parameters of the system.
3. **Sensitivity Analysis**: A sensitivity analysis needs to be carried out to ascertain the variation of optimal solution value and solution point with respect to parameter values and variable bounds. Intuitively, the solution is expected to be less sensitive to minor variations in parameter values in transfer operations or contractual agreement because there is enough slack in the system to adjust it.
4. **Complexity**: An economic representation of the system could be built on top of the model presented here where the contractual modeling framework is extended to include complex commercial and economic rules. It can also consider the larger problem for multiple time periods and continuous time scheduling formulation. The problem is solved with the 30 days or as short term scheduling problem. While the planning for resources and utilities can be more number of days
5. **Implementation issue**: The issue to implement in Decision support system developed in thesis requires lot of considerations including software, database,

compatibility, access and privacy, data mining and software integration. This can be combined with the model can form a good part of the real life application. A systematic mechanism to trace infeasibility of the model to specific delivery specifications and contractual rules is needed for a good implementation because determining the source of infeasibility is not always obvious because the effect of constraints can propagate through the network to appear far away from the concerned constraint.

Conference Publications

Rajnish Kumar, I.A. Karimi, "*Planning and Scheduling of Supply/delivery Operations in an LNG Regasification Terminal",* AICHE Annual Meeting, San Francisco, USA, Nov 7, 2013.

Rajnish Kumar, I.A. Karimi "*Supply chain optimization of LNG downstream processing terminal*", World Congress of Chemical Engineering, Seoul, South Korea, Aug 21, 2013

Chapter 4

CASE STUDIES OF UNLOADING, INVENTORY AND OPTIMAL DELIVERY STRATEGY

In previous chapter, we have developed MILP based scheduling model formulation which can minimize the total operating costs that include the holding, demurrages, and order delay penalties. The terminal operations is a critical part of large scale LNG supply chain. The problem will enable us to solve real life operational decisions such as incoming time, volume of order delivery, inventory levels, contracts, boil-off gas etc. To take the decision that provides us the optimal decisions and apply it for business purpose has always been a challenge. In this chapter, we discuss how the model developed in chapter 3 can be applicable for taking business related decisions.

The data is assumed but very close to real terminal operation data. There are two examples, first one is motivating example that describes how the model can help to take decision on short term basis.

4.1 Motivating Example

Consider the planning horizon of 10 days and the planning horizon is divided into 10 equal time interval. There are two incoming vessel of capacity 120,000m^3 arrives at the terminal. The arrival time of the two vessals and their capacities are known in advance. The order vessel sequence timing and their capacities are known in advance and is shown in the figure. The change within the time period remains unchanged. The sequence can be shown in figure below

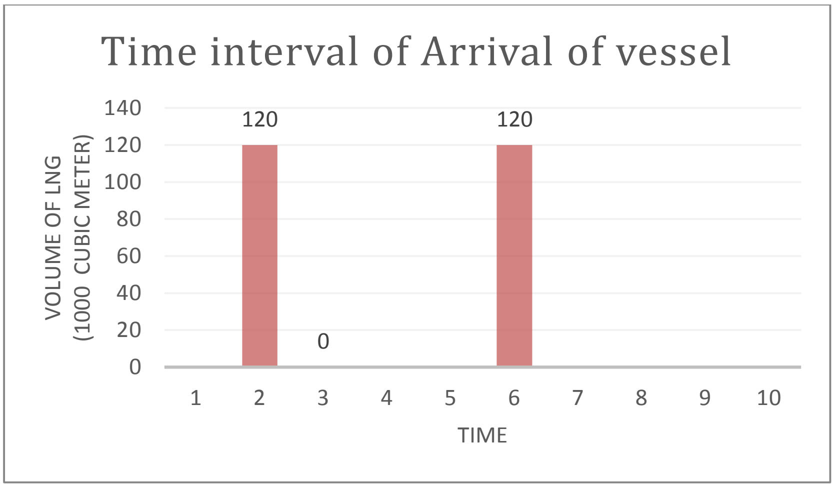

Figure 4.1: Arrival of LNG vessel at terminal and its carrying capacity

There are two vessel of 120,000m^3 capacity arriving at time period t2 and time period t6. The order parcels arrives at period t1, t3, t5 and t7. The order parcel has smaller volume compared to the LNG vessel. The capacity of each is known in advance. The vessel has to unload the entire volume of LNG at the terminal and storage tank must fill the maximum possible volume of order parcel.

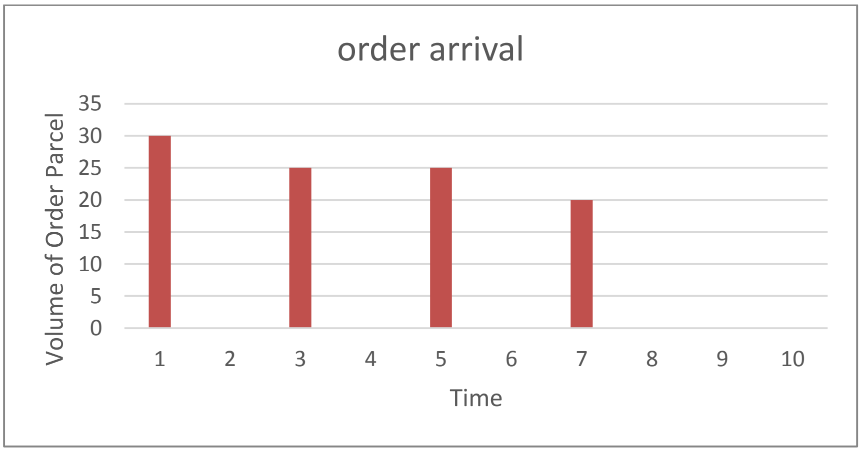

Figure 4.2: Arrival of order parcel for loading operation and its maximum capacity

It can been see that in first 7 periods, all the loading and unloading operations are completed and last 4 period demands are fulfilled with inventory. It is important to manage inventory for the better operations and delivery.

Demands (time)	1	2	3	4	5	6	7	8	9	10
Customer 1	16	17	18	17	20	25	22	21	29	22
Customer 2	14	12	18	14	12	14	16	14	10	14
Customer 3	18	11	14	18	11	14	11	18	11	14

Table 4.1: Customer demands at various time interval for motivating example

There are three customers, each of which is have daily demands. The daily demands can be fulfilled by the regasifying natural gas. We can see in this short time, customer 1 have the demand range from 16000 to 29000 m^3. We can also see that customer 2 demand changes a little from 12000-16000m^3 per time interval. It is because of the customers agree on different kinds of contracts and these may be different source of demand. The residential demands changes more than the demands from electricity companies. So the nature of three customers can be different. There is a penalty for each time the order parcel is undelivered or the customer order is not fulfilled. The penalty is function of the volume of the shortfall as discussed in chapter 3, and hence the model will never be infeasible. This MILP model is solved in GAMS.

In this example, it is assume that there is no linepack. Places like Singapore and Korea, there are liberalised natural gas grid and hence the linepack is not considered in this example. This also shows that out model is quite flexible and can adapt to be customized.

Solution

The model is solved using the data given in the problem. Using the MILP model discussed in the previous chapter, we solve the optimal delivery problem. The solution is presented in graphical form for better and each figures are discussed.

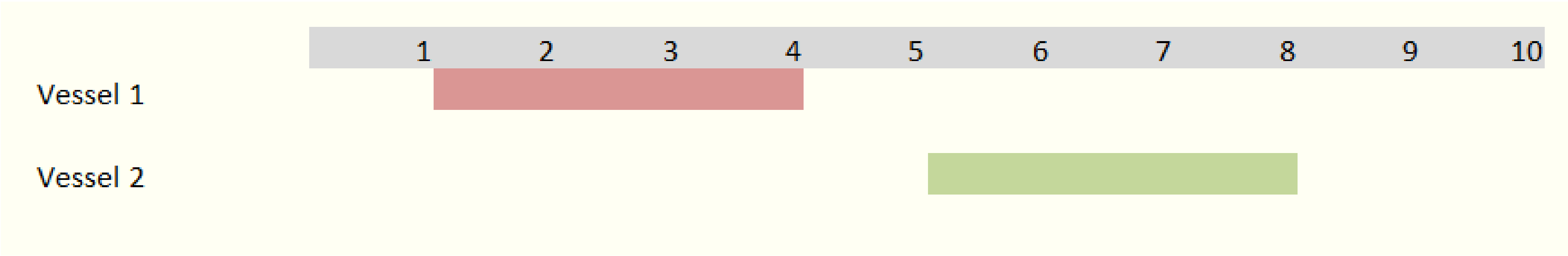

Figure 4.3: Optimal Solution of vessels scheduling on jetty for motivating example

Vessel 1 arrives at jetty at the end of time interval 1, and starts its transfer operation. It stays it till the end of the time interval 4. Vessel 2 arrives at jetty at the end of time interval 5, and starts its transfer operation. It stays it till the end of the time interval 8. The transfer operations are scheduled for simultaneous transfer in either of the available tank for the given time interval. There is a deliberate delay imposed by the optimizer, as the demurrage cost is less than the penalty of the shortfall.

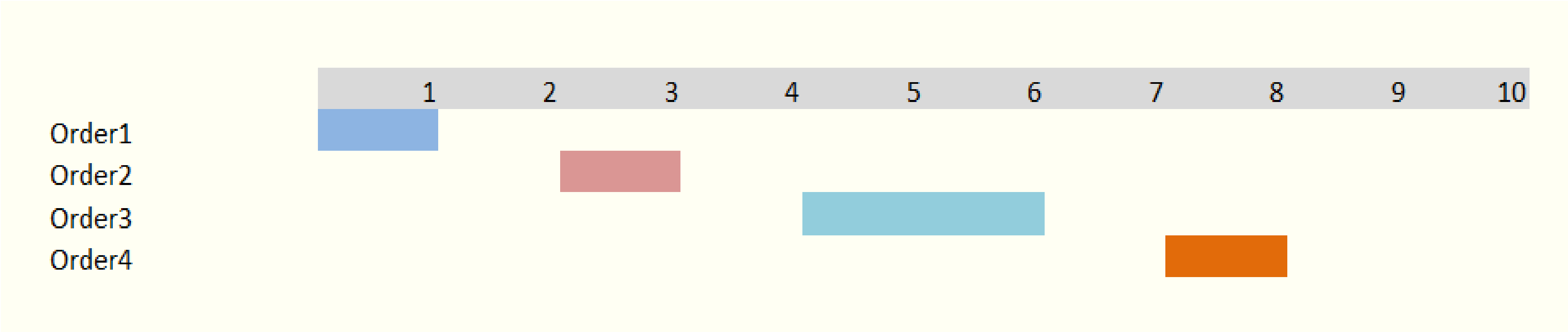

Figure 4.4: Optimal Solution of order delivery scheduling and their volume

Order 1 arrives at jetty at the beginning of time interval 1, and starts its transfer operation. It stays it till the end of the time interval 2. Order 3 arrives at jetty at the beginning of time interval 2, and starts its transfer operation. It stays it till the end of the time interval 2. Similarly order 3 and order 4 arrives on jetty at end of time interval 4 and time interval 7 respectively. The transfer operations are scheduled for simultaneous transfer from either of the available tank for the given time interval.

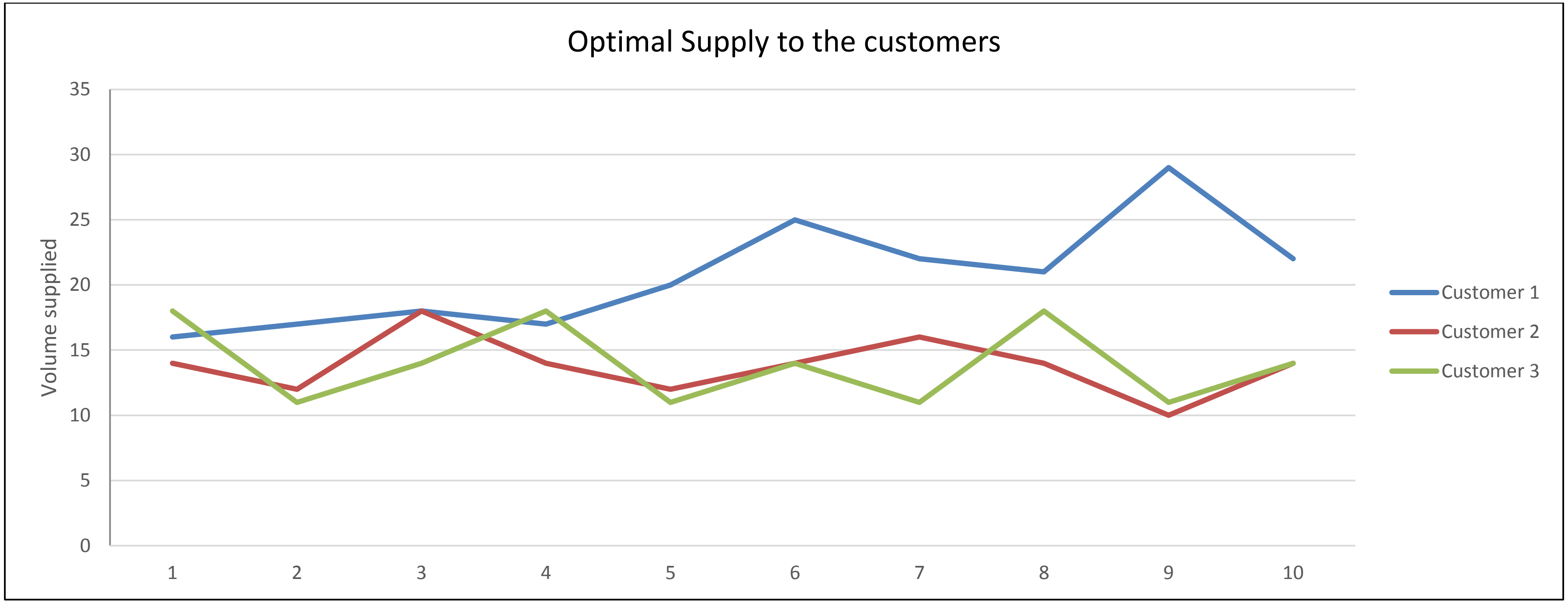

Figure 4.5: The optimization based solution for the optimal delivery to the customers.

Customer demands as shown in figure 4.5 can be met by supply natural gas after regasification. The supply portfolio can be seen in figure The optimal delivery portfolio minimizes the penalty occurred by the terminal company and maximizes the benefits from excess supply.

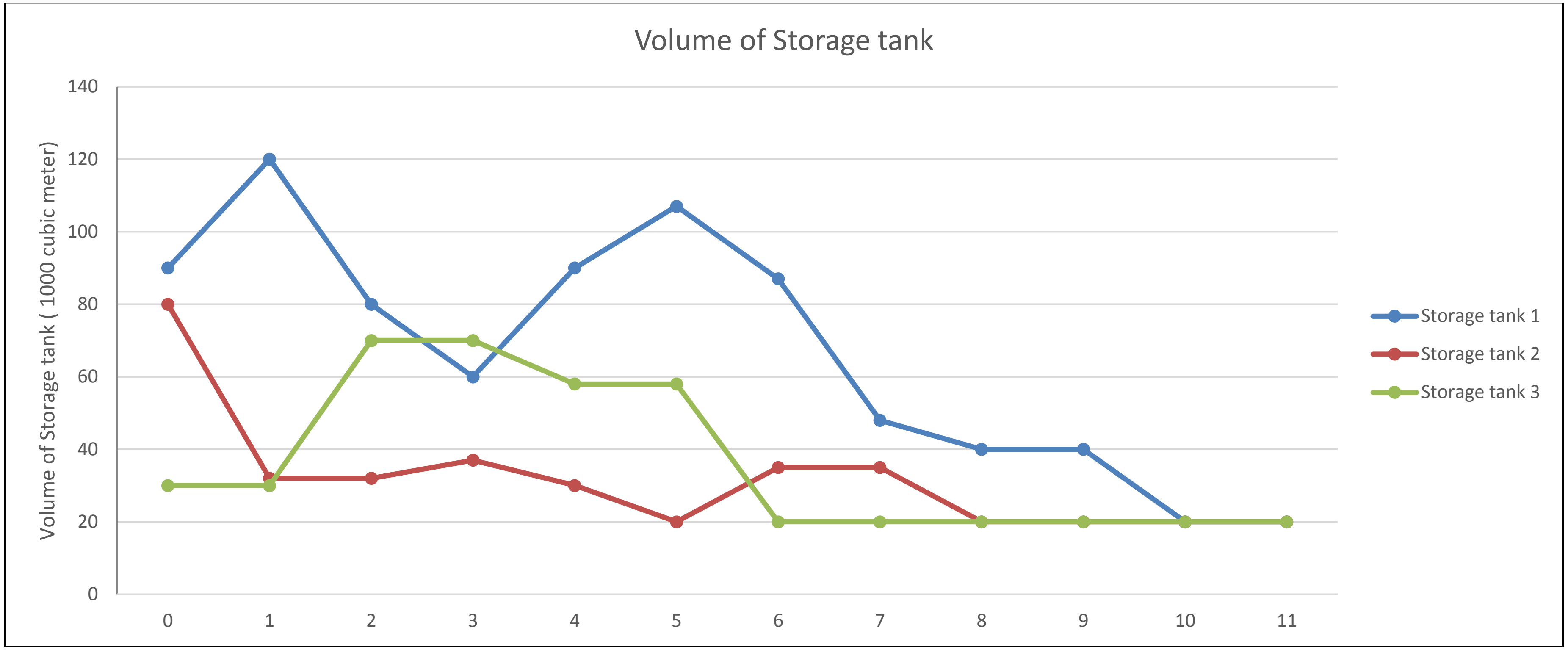

Figure 4.6: Inventory positions for various storage tanks for motivating example.

Model optimal solution minimizes the inventory and at the end of the planning horizon it minimizes the inventory. This way, we can reduce the operating cost of the inventory and also minimizes the opportunity loss due to capital equivalent of excess cargo holding in present value.

Orders highlighted in the figure, are the slots at which transfer operation takes place. The order is loaded for 1 time interval for order 1, order 2 and order 4 while for order 3 it takes 2 time interval. It should be noted that the volume of parcel 1 is more than parcel 3 but parcel 3 is taking more time. This is to minimize the overall costs, and to reduce the penalty for natural gas delivery to different customers.

All the demands from the customers are met. This is because there is a penalty for not meeting the demand, and also there is an excess revenue if the extra natural gas is supplied. So model looks at the potential future demand and proposes to supply extra or not.

The position of inventory is very important. The operating costs of inventory is relatively low. But it minimizes the inventory and hence the costs of it.

There are demurrages that are incurred during the planning horizon:

Vessel 1: 1 day;

Vessel 2: 1 day

Order parcel 3: 1 day.

In model example we can see that the various demands and supply and how optimization model based decision support tool can help to minimize the operating cost

4.2 Case Study 1

Consider a company ABC which operates the LNG regasification terminal with initial capacity given as below. We consider 4 identical tanks each of which has capacity of 180,000m^3 which transfers LNG from incoming vessels and outgoing parcel. Each time interval is 10hours, and the scheduling operation is solved for 40 time intervals. The LNG terminal owner is in long term contract with six customers, each of which has different demand profile over the time horizion. Here each time interval is 10 hours. It is assumed that operations between the time horizons remain the same. Given below is the intial known state of inventory. The entire three inventories are having maximum volume of 200,000 m^3 however actual capacity is 180,000 m^3 and there a head left to vent out boil off gases. There is a constant boil off in the tanks, and hence to maintain the storage tank always cool there has to maintain LNG heel. The heel for these storage tanks are 20,000 m^3.

Storage Tank	Initial Inventory(m3)	Storage Capacity(m3)
1	180000	200000
2	80000	200000
3	130000	200000

Table 4.2: Initial inventory and storage capacity of case study 1

Initial inventory is 180,000, 80000 and 130,000 m^3.

The terminal has contracts long term with 6 customer and each customer has different LNG price and penalty indexes.

	Sequence and volume of vessels and parcel (in '000m3)	
	Time of Arrival of LNG Vessel	**Time of Arrival of order Parcel**
1		30
2	120	
3		25
4		
5		30
6		
7	100	20
8		
9		30
10		25
11	110	
12		
13		40
14		
15	130	20
16		
17		30
18		
19	160	25
20		

21		30
22		
23		20
24	120	
25		30
26		
27		25
28	100	40
29		
30		20
31		
32	140	25
33		
34		30
35		20
36	110	40
37		
38		
39		
40		

Table 4.2: Expected Arrival time for vessel and order parcel and their capacity of case study 1

These are the sequence of arrival of LNG vessel and order parcel is given in the table above. Similarly, orders are characterized by their volumes, delivery rate from the tanks, their delivery time window as well as the penalties for delay and earliness associated with them. While each parcel to transfer into more than one tank, an order delivery is restricted from a particular tank as each tank is designated to deliver only single - LNG orders.

As you can see that the size of the vessels can be different and also the size of the order vessels can be of varying size. This can be quite tedious to manage without the modelling and optimization in real life. The problem like this can be rigorous and often requires large scale optimization. The demand from customers is given below:

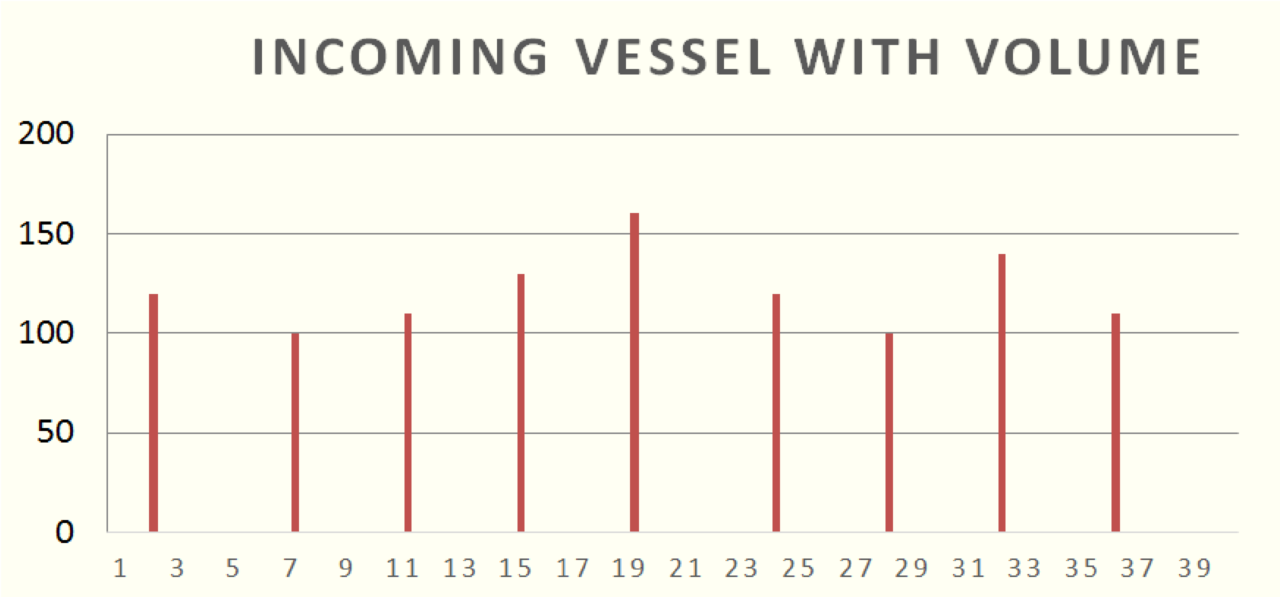

Figure 4.7: Incoming LNG vessels, their expected date of arrival, and its capacity for case study 1

The incoming vessel expected time of arrival with capacity is given in the figure. The vessel 1 arrives at 2nd time interval and has the capacity of 120,000 m^3. Similarly other 8 vessels time and capacities are known in priori. The demurrages are incurred it the vessel takes longer than the allocated time, and there is penalty for the incurred time.

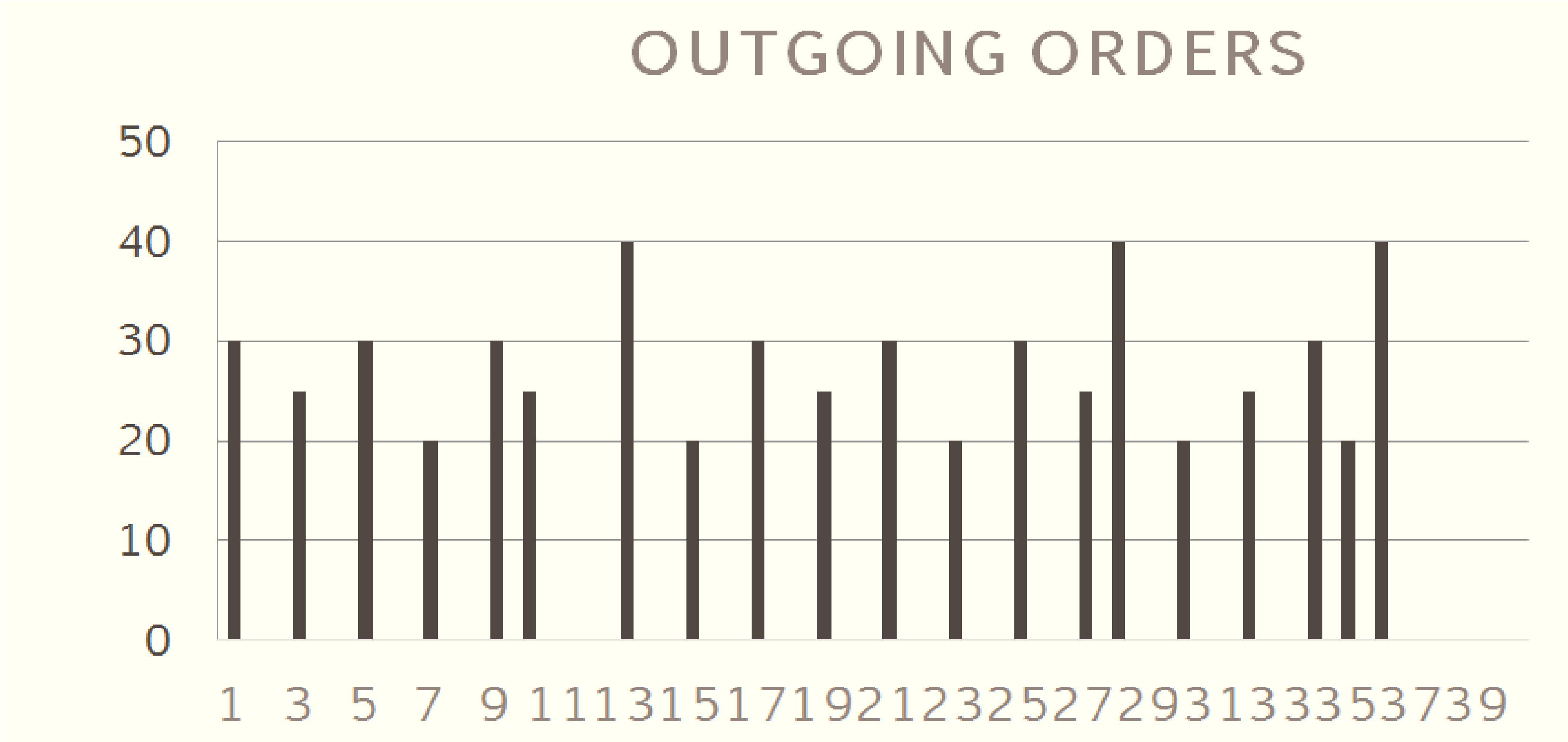

Figure 4.8: Outgoing order parcel, their expected date of arrival, and its capacity for case study 1

The Outgoing order parcel expected time of arrival with capacity is given in the figure. The order 1 arrives at 1st time interval and has the capacity of 30, 000 m^3. Similarly other 19 order parcel's time and capacities are known in priori. The demurrages are incurred it the order parcels takes longer than the allocated time, and there is penalty for the incurred time.

Time	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
C1	16	17	18	17	20	25	22	21	29	22	16	17	18	17	20	25	22	21	29	22
C2	14	12	18	14	12	14	16	14	10	14	16	17	18	17	20	25	22	21	29	22
C3	16	17	18	17	20	25	22	21	29	22	16	17	18	17	20	25	22	21	29	22
C4	14	12	18	14	12	14	16	14	10	14	16	17	18	17	20	25	22	21	29	22
C5	16	17	18	17	20	25	22	21	29	22	16	17	18	17	20	25	22	21	29	22
C6	10	11	12	12	11	14	11	12	12	10	11	12	12	11	14	11	12	12	11	14

Time	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
C1	16	17	18	17	20	25	22	21	29	22	16	17	18	17	20	25	22	21	29	22
C2	25	22	21	29	22	16	17	18	17	20	25	22	21	29	22	16	17	18	17	20
C3	16	17	18	17	20	25	22	21	29	22	16	17	18	17	20	25	22	21	29	22
C4	25	22	21	29	22	16	17	18	17	20	25	22	21	29	22	16	17	18	17	20
C5	16	17	18	17	20	25	22	21	29	22	16	17	18	17	20	25	22	21	29	22
C6	10	11	12	12	11	14	11	12	12	11	14	10	11	12	12	11	14	11	12	12

Figure 4.9: Demands from customers for different time interval for case study 1.

In the case study 1, six different customers are considered in the model. The customers are mainly power generation companies that uses natural gas to produce electricity. The demand changes based on the demands for the electricity. The demands given in the figure are the expected demand forecast.

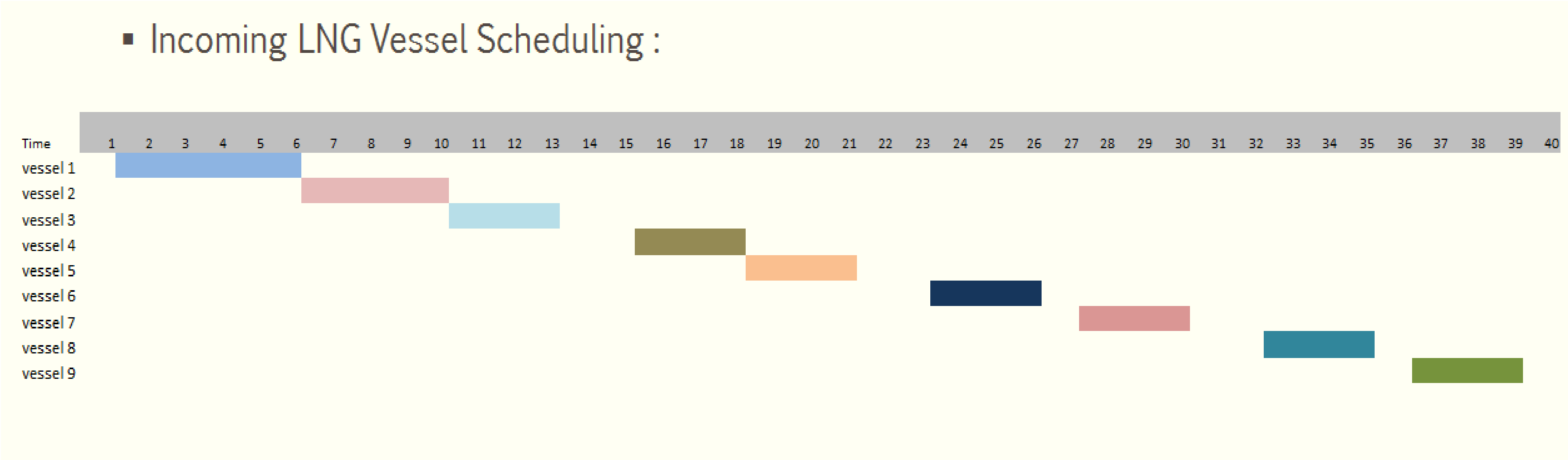

Figure 4.10 : Optimal Scheduling of the incoming vessel for case study 1

The optimal scheduling for the incoming LNG vessel is shown in the figure. The vessel 1 transfer operation takes place from the end of time interval 1 till the end of time interval 6. Similarly for the other 8 incoming vessel.

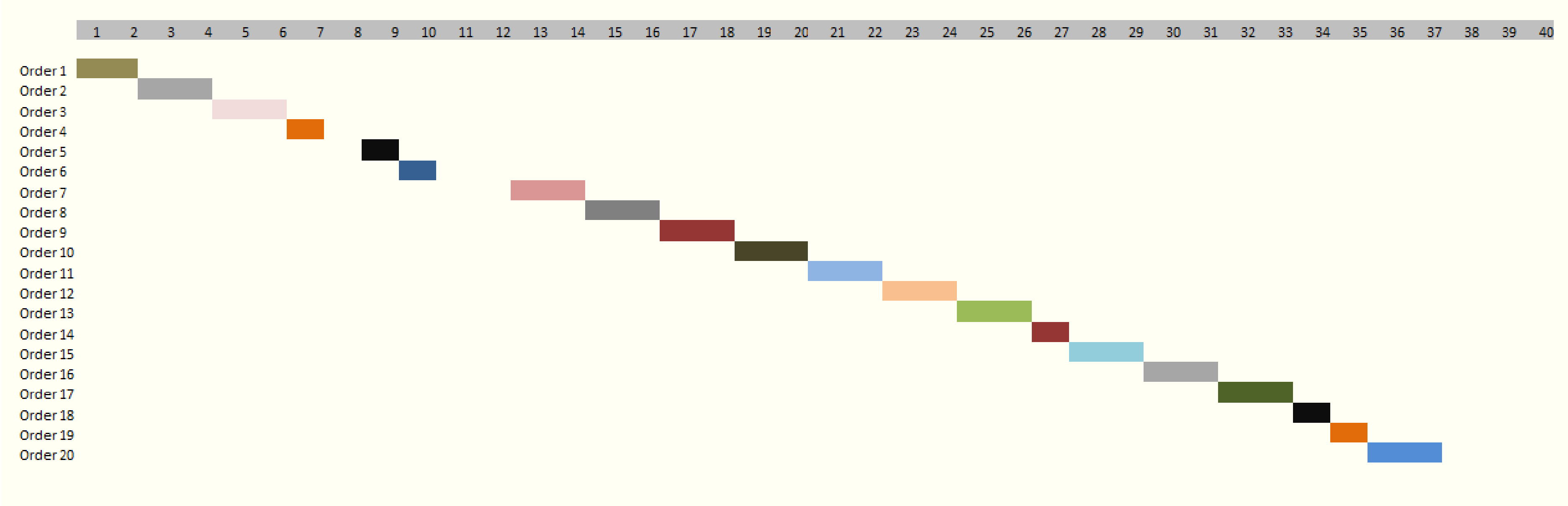

Figure 4.11: Optimal Scheduling of the outgoing LNG order parcel for case study 1

The optimal scheduling for the incoming LNG order is shown in the figure. The order parcel 1 transfer operation takes place from the beginning of time interval 1 till the end of time interval 1. Similarly for the other 19 outgoing order parcels.

Figure 4.12: Optimal delivery of natural gas for the customers at terminal for case study 1

The optimal delivery portfolio is shown in the figure. The demands are met, and penalty is incurred if there is any shortfall. At the same time, there is excess cost involved if the customer is buying about the limit mentioned in the contracts.

Solution

The optimal LNG vessel scheduling is given in the given in the figure below. It could be noted that the LNG vessels arrival time is at uniform interval. However this may not be the case always and sometimes the vessel can be coming together. The decision to choose one and wait for other outside jetty depends on the the demurrage costs which is dependent on the type of vessel, volume and its contracts with the shipping company.

The demurrages for LNG Vessels are given below:

Vessel 1- 2 days

Vessel 2- 1 day

Vessel 3- 1 day

Vessel 9- 1 day

For order parcel, it can be even more complicated because of more number of decisions.

The demurrages for LNG order parcel are:

Order2 - 1 day

Order3 - 1 day

Order6 - 1 day

Order7 - 1 day

Order9- 1 day

Order 11- 2 days

Order 16- 2 day

Order 20- 1 day

For the optimal supply portfolio, we need to devise the regasification, contracts and linepack storage. Below is the optimal regasification portfolio that is should be followed for maximizing the profit.

The demand from six contracts have been met and the all the operations have been working under the constraint. Optimal Solution: $426991 (Profit from gas sales) including penalties paid in terms of demurrage and lower supply.

4.3 Case study 2

This is the second case study which involves stringent decisions considering complex case, where multiple vessel arriving at the nearly same time, and there is fluctuations in demands. Consider a company ABC which operates the LNG regasification terminal with initial capacity given as below. We consider 4 identical tanks each of which has capacity of 180,000m^3 which transfers LNG from incoming vessels and outgoing parcel. Each time interval is 10hours, and the scheduling operation is solved for 40 time intervals. The LNG terminal owner is in long term contract with six customers, each of which has different demand profile over the time horizon. Here each time interval is 10 hours. It is assumed that operations between the time horizons remain the same. Given below is the intial known state of inventory. The entire three inventories are having maximum volume of 200,000 m^3 however actual capacity is 180,000 m^3 and there a head left to vent out boil off gases. There is a constant boil off in the tanks, and hence to maintain the storage tank always cool there has to maintain LNG heel. The heel for these storage tanks are 20,000 m^3.

Storage Tank	Initial Inventory(m3)	Storage Capacity(m3)
1	180000	200000
2	80000	200000
3	130000	200000

Table 4.4: Initial inventory and storage capacity of case study 2

Initial inventory is 180,000, 80000 and 130,000 m^3.

The terminal has contracts long term with 6 customer and each customer has different LNG price and penalty indexes.

	Sequence and volume of vessels and parcel (in '000m3)	
	Time of Arrival of LNG Vessel	**Time of Arrival of order Parcel**
1		30
2	200	
3	160	25
4		
5		30
6		
7	180	20
8		
9	160	30
10		25
11	160	
12		
13	160	40
14		
15		20
16		
17		30

18		
19		25
20		
21		30
22	160	
23	250	20
24		
25		30
26		
27	150	25
28		40
29		
30		20
31	180	
32		25
33		
34		30
35		20
36		40
37	180	
38		
39		
40		

Table 4.5: Expected Arrival time for vessel and order parcel and their capacity of case study 1

These are the sequence of arrival of LNG vessel and order parcel is given in the table above. Similarly, orders are characterized by their volumes, delivery rate from the tanks, their delivery time window as well as the penalties for delay and earliness associated with them. While each parcel to transfer into more than one tank, an order delivery is restricted from a particular tank as each tank is designated to deliver only single - LNG orders.

As you can see that the size of the vessels can be different and also the size of the order vessels can be of varying size. This can be quite tedious to manage without the modelling and optimization in real life. The problem like this can be rigorous and often requires large scale optimization. The demand from customers is given below:

In the second case study which has 3 storage tanks, 11 vessels, 20 set of orders and 10 customers. The time horizon is considered to be 40 time period, and each time periods are of 10 hours.

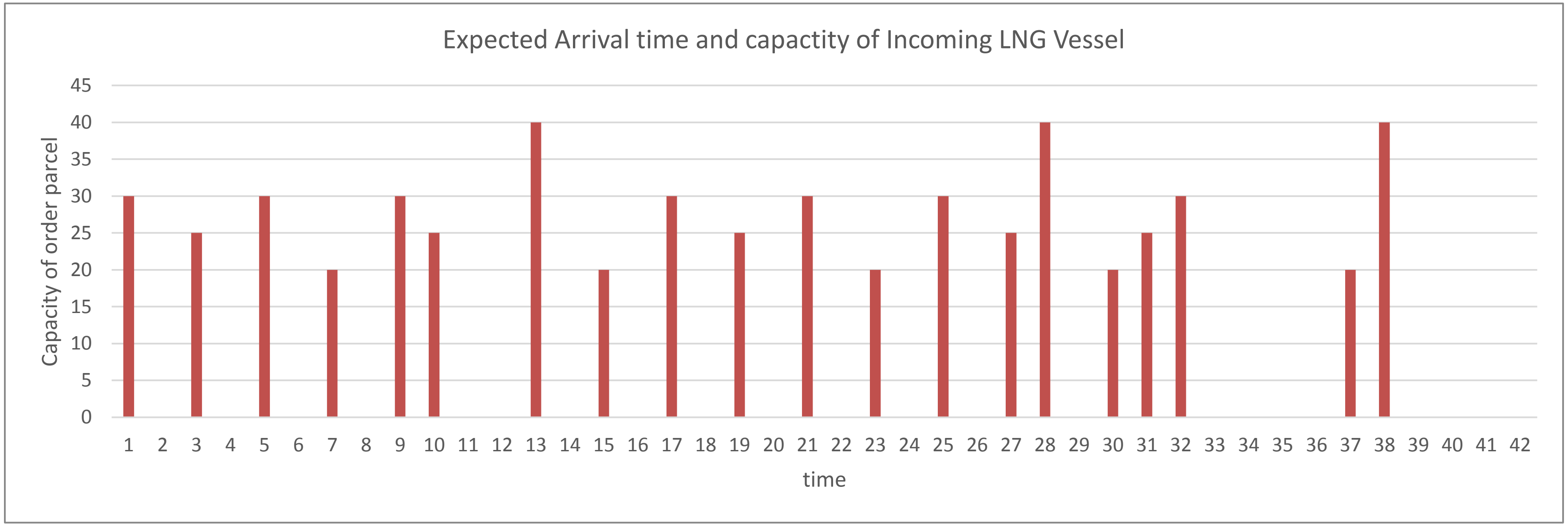

Figure 4.13: Expected time of arriaval and capacity of outgoing parcel vessel for case study 2

The Outgoing order parcel expected time of arrival with capacity is given in the figure. The order 1 arrives at 1^{st} time interval and has the capacity of 30, 000 m^3. Similarly other 19 order parcel's time and capacities are known in priori. The demurrages are incurred it the order parcels takes longer than the allocated time, and there is penalty for the incurred time.

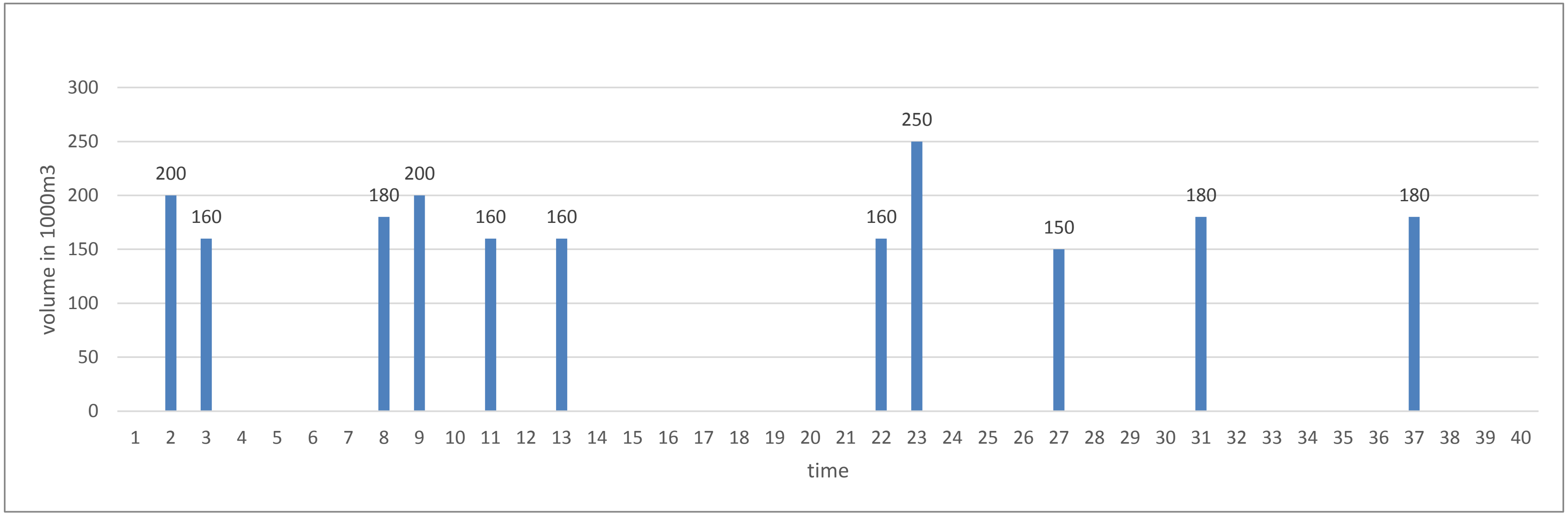

Figure 4.14: Expected time of arriaval and capacity of incoming vessel for case study 2

The incoming vessel expected time of arrival with capacity is given in the figure. The vessel 1 arrives at 2nd time interval and has the capacity of 200,000 m^3. Similarly other 10 vessels time and capacities are known in priori. The demurrages are incurred it the vessel takes longer than the allocated time, and there is penalty for the incurred time.

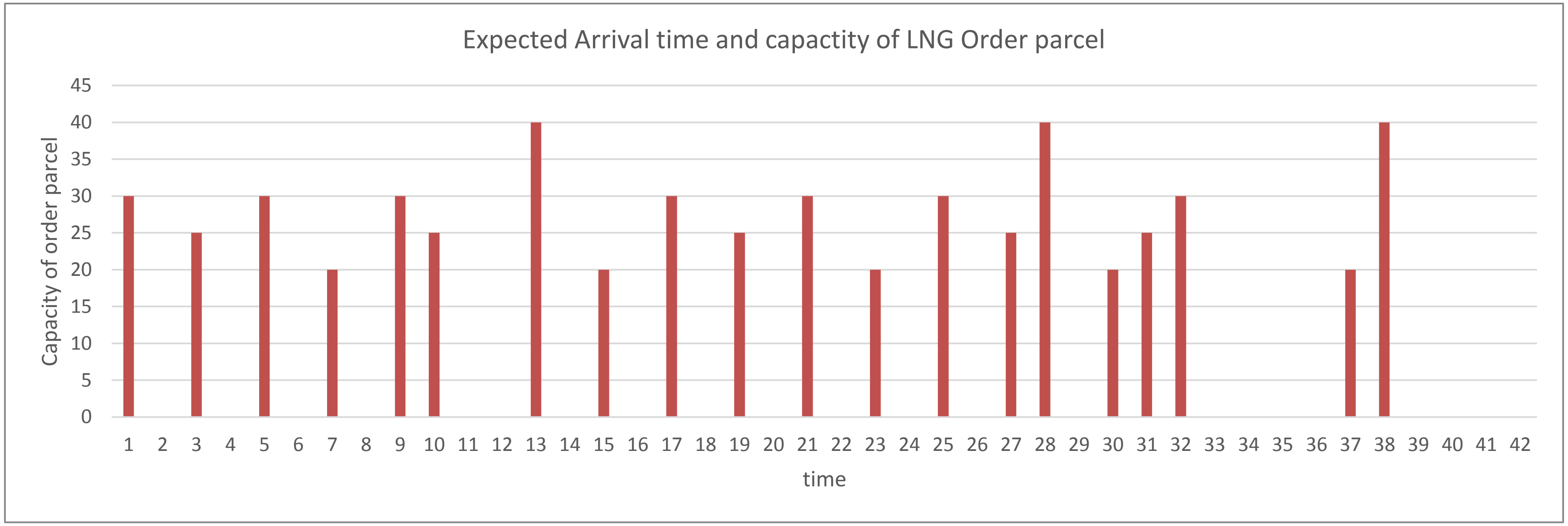

Figure 4.15: Expected time of arriaval and capacity of outgoing parcel vessel for case study 2

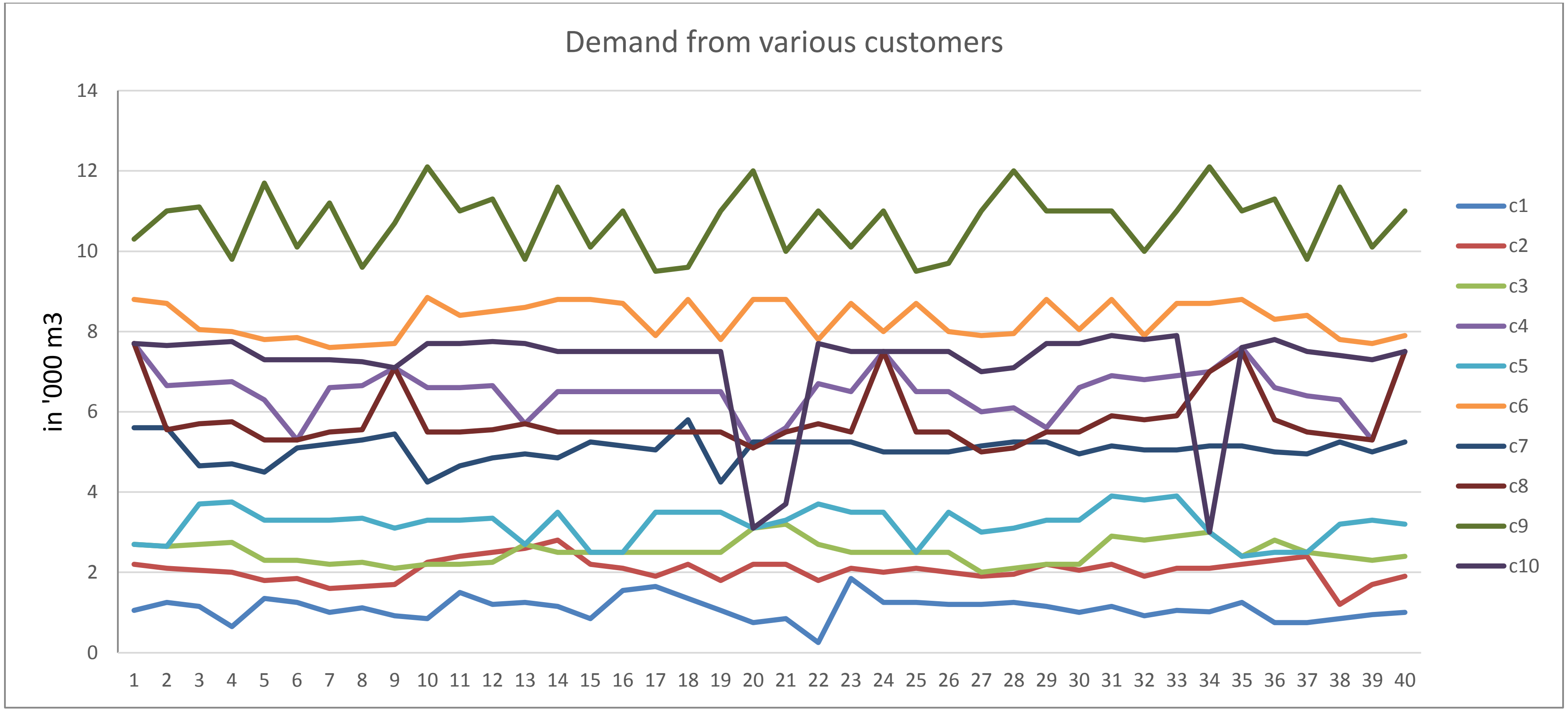

Figure 4.16: Demands from the various customers.

The demands fluctuates on the daily basis, and to operate it is a challenging task for the operator. In the case study 1, six different customers are considered in the model. The customers are mainly power generation companies that uses natural gas to produce electricity. The demand changes based on the demands for the electricity. The demands given in the figure are the expected demand forecast.

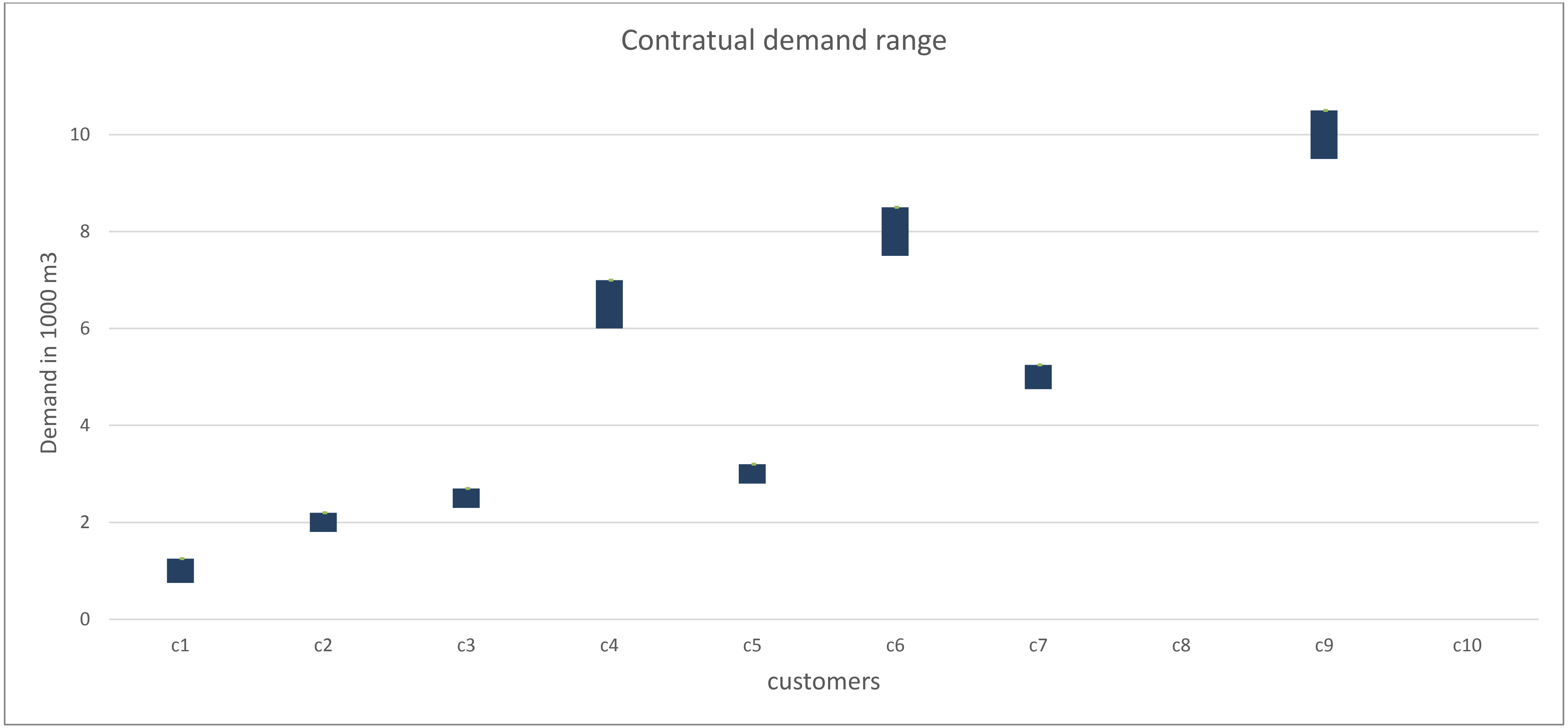

Figure 4.17: Contractual range for the various contracts at the terminal.

Any demand above allowable range or below this range is subject to penalty.

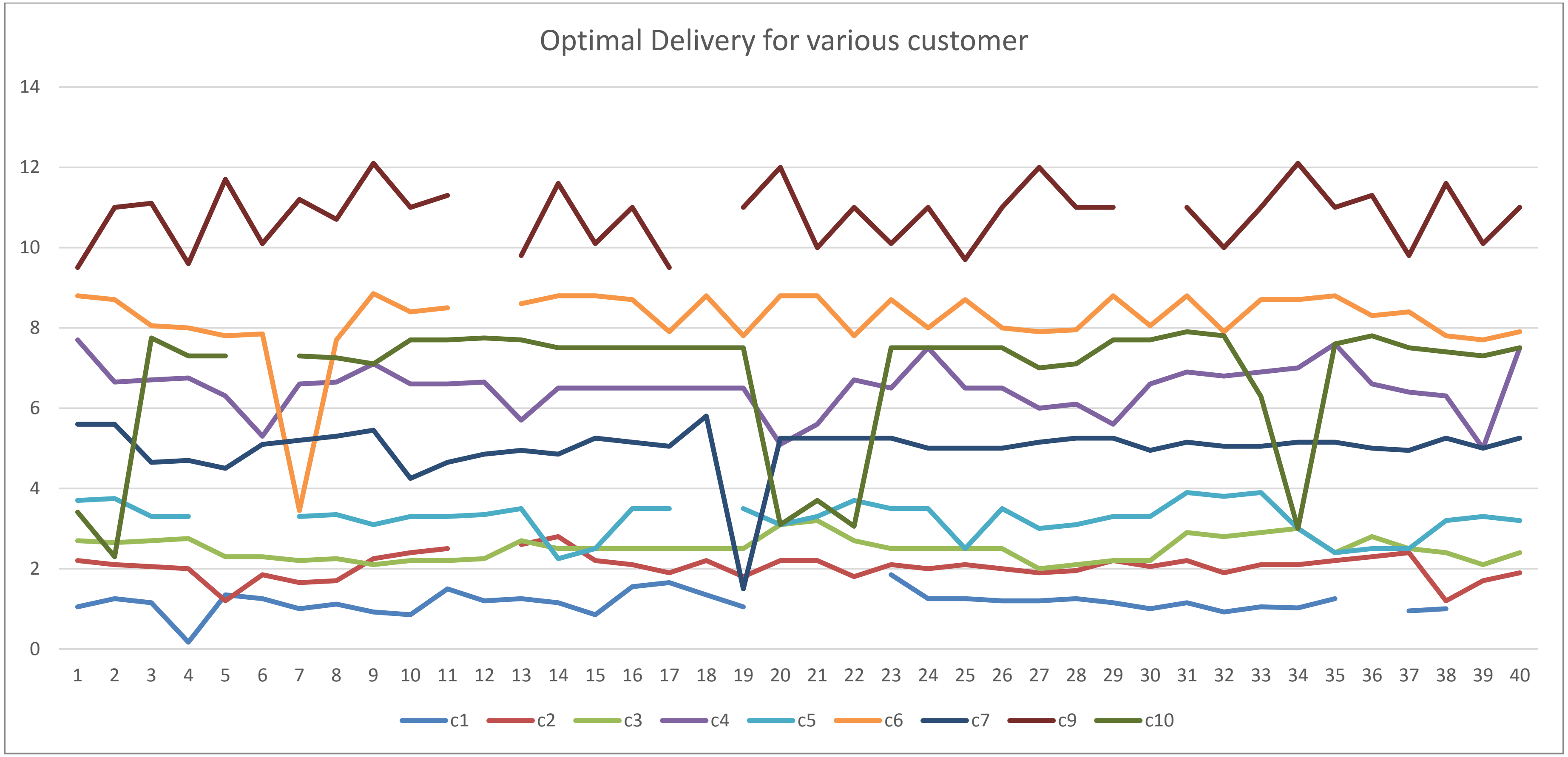

Figure 4.18: Optimal delivery for various customer at the terminal.

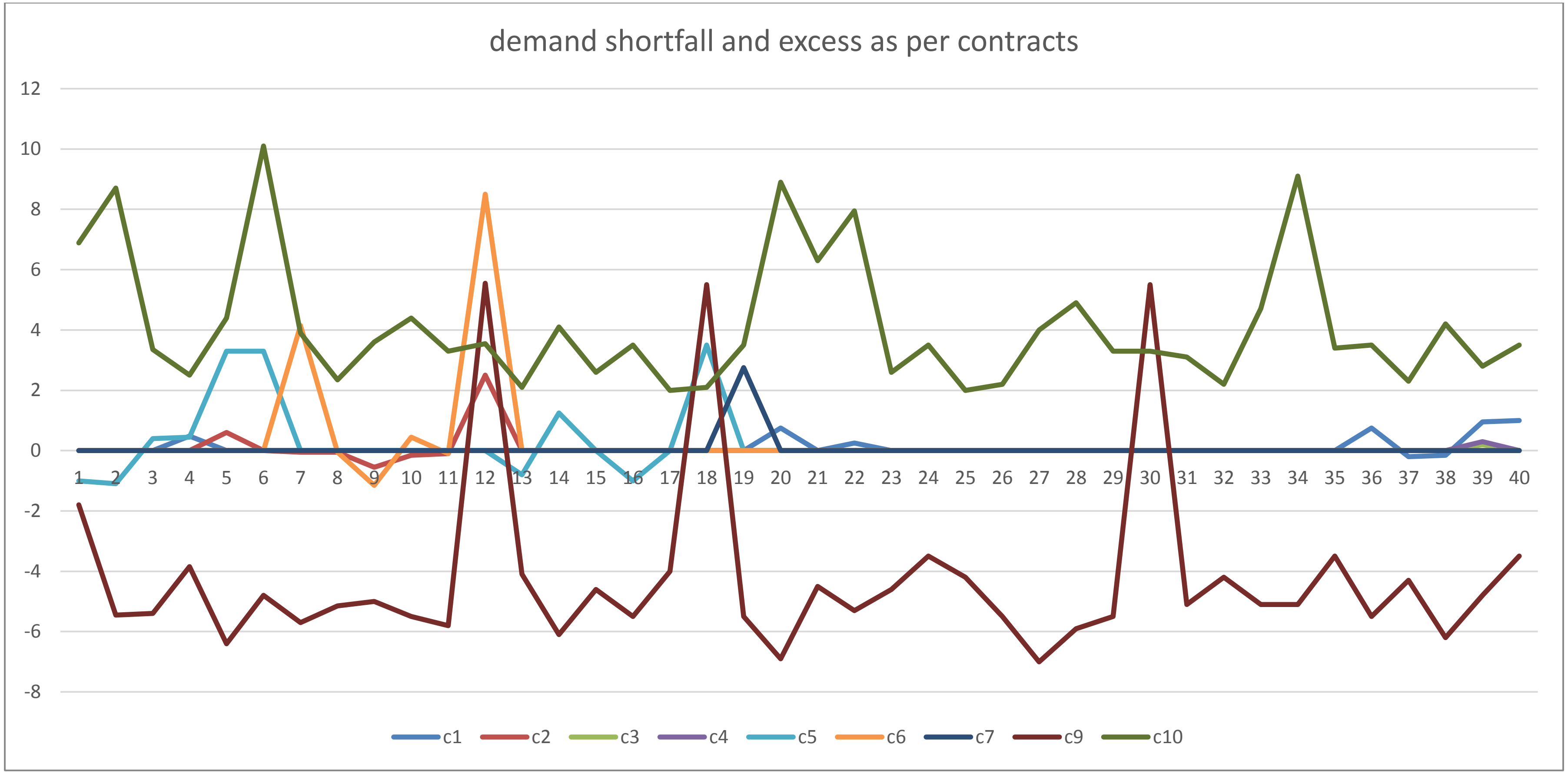

Figure 4.19: Demand shortfall and excess as per the contracts

This is the shortfall and excess demand to various customers at the terminal. Excess demand is mostly for short term contracts where there is no contacts for minimum or maximum demand limit. cases

The optimal LNG vessel scheduling is given in the given in the figure below. It could be noted that the LNG vessels arrival time is at uniform interval. However this may not be the case always and sometimes the vessel can be coming together. The decision to choose one and wait for other outside jetty depends on the the demurrage costs which is dependent on the type of vessel, volume and its contracts with the shipping company.

The demurrages for LNG Vessels are given below:

Vessel 2- 4 days

Vessel 2- 1 day

Vessel 4- 4 day

Vessel 6- 3 day

For order parcel, it can be even more complicated because of more number of decisions.

The demurrages for LNG order parcel are:

Order2 - 1 day

Order3 - 1 day

Order6 - 2 day

Order7 - 1 day

Order9- 1 day

Order 11- 2 days

Order 16- 2 day

Order 20- 1 day

For the optimal supply portfolio, we need to devise the regasification, contracts and linepack storage. Below is the optimal regasification portfolio that is should be followed for maximizing the profit.

The demand from six contracts have been met and the all the operations have been working under the constraint. Optimal Solution: $426991 (Profit from gas sales) including penalties paid in terms of demurrage and lower supply.

For the optimal supply portfolio, we need to devise the regasification, contracts and linepack storage. Below is the optimal regasification portfolio that is should be followed for maximizing the profit.

The demand from six contracts have been met and the all the operations have been working under the constraint. Optimal Solution: $606626 (Profit from gas sales) including penalties paid in terms of demurrage and lower supply.

Disruption in Supply Chain optimization

In recent years, supply chains have become longer and more complex, while the severity and frequency of supply chain disruptions seems to be increasing. Natural disasters and extreme weather conditions are not the only threats to supply chains. Systemic vulnerabilities, such as oil dependence, political regime confrontations, information hacking, also pose serious risks, as do political unrest, cybercrime and the rising cost of insurance and finance. Supply chain efficiency, which is directed at improving a company's financial performance, is different from supply chain resilience, whose goal is risk minimization and uncertainty reduction. The uncertainty requires to focus on matching on demand and supply, the disruptions requires resilience against the additional costs. Companies have redefined the concept of Operations and its management using the supply chain perspective through the incorporation of upstream and downstream partners into the boundary of management (Bettley & Burnley, 2008). Traditionally, Supply chain management has been defined as the management of financial physical flows in networks of intra- and inter-department relationships adding value and achieving goals of the organization (Mentzer et al., 2001; Stock & Boyer, 2009).

Disruptive risks tend to have a domino effect on the supply chain: An impact in one area — for example, a cyclone in one region — can affect the entire downstream LNG terminal supply. Such a risk can't be addressed by holding additional parts inventory without a substantial loss in cost efficiency, or can be rescheduled at the expected time span. By contrast, recurrent risks such as demand fluctuations or supply delays tend to be independent.

We believe, that steps taken to improve supply chain resilience – such as building a culture of risk management across suppliers; improved alert and warning systems; identification and elimination of supply chain bottlenecks; and improved information sharing between government and business – are both good business practices and important preparedness measures. Low-cost offshore suppliers with long lead times leave companies vulnerable to long periods of shutdown when particular locations or transportation routes experience problems. Companies that undertake such measures as part of a comprehensive blueprint for supply chain resilience will be in a much better position, not only to bounce back from potential disruption, but to gain legitimate competitive advantage from such events.

When a disruption occurs, businesses need to have mitigation plans in place to prevent loss of market share to better prepared or less affected competitors.

It is increasingly clear that supply chains established during more stable times need to be reshaped for operation in an era of increased volatility. Elements of what we call “dynamic operations” can help accomplish this. For example: Supply chain operators should be able to synthesize external and internal data and rapidly take action to minimize the impact of a disruption.

Supply chain management should be flexible and adaptable so that it can adjust to the market and contractual needs. Hierarchy organizational structure, with well-defined responsibilities and coordinated department can respond faster to the change in supply chain and can reduce the confusion. It can also help taking quick decisions and subsequent actions, in case of any disruptions

Supply chain managers also need to strike a balance between efficiency and effectiveness. They need a diversity of activities, suppliers and markets rather than an overspecialization in one sector, or a total dependence on a key supplier.

Disruption risk may arise from many different sources:

1. Operational Contingencies. These include equipment malfunctions and systemic failures, discontinuity of supply, for instance when a main supplier goes out of business; bankruptcy and other less severe forms of financial distress; and human-centred issues ranging from strikes to fraud.

2. Natural Hazards Earthquakes, Hurricanes, and Storms. For instance, the recent flood in Japan, or series of tsunamis in India, or cyclones in Philippines or Kobe earthquake in Japan caused huge transportation disruptions in Asian market and huge loss to the industry.

3. Terrorism and Political Instability. The increasing terrorism and political instability has affected supply chain, and increased the complexity of the supply chain, from global outsourcing to the energy market.

A disruption handling system should be capable of detecting abnormal situations before they occur, diagnosing the root cause, and proposing corrective actions as required.

4.4 Disruption in Oil & Gas

Minor disruption or uncertainty can cause the price to change with extreme volatility. Every year snowfall in US causes the henry hub natural gas spot prices to go as high as $20/MMBUT from its usual contractual price of $2-3/MMBTU.

Future disruptions almost certainly will occur since demand in the world is now near maximum world production levels. Yet, there is extreme danger that the disruptions to the oil supply within the next two decades will become much worse than any of these recent simulations or the disruptions caused by nature. Political instability, financial uncertainty, geological challenges, demographic constraints and other factors have caused the supply chain in Oil & Gas industries even more.

LNG is capital intensive business and any disruption can cause to lose millions of dollars. Expanding the number of suppliers often increases risk exposure, which can be most effectively moderated by pulling supplies from widely varied sources. Part 1 of the article (OGJ, Apr. 16, 2007, p. 57) examines the risks faced by the countries as it expands sources of its natural gas supplies, as well as efforts made to address these risks.

As countries gets in collaboration with more and more countries, the measures against disruptions gets more and more important.

Most of the literature dealing with Oil and gas production scheduling and its supply chain involves the finding of a schedule over a given time horizon assuming other factors are known or problems are deterministic. Such scheduling are done well in advance with forecasting based on the history data and often produced in advance in order to direct operations and to support other planning activities such as drilling, transportation, regasification, natural gas delivery, contracts, resource allocation etc. Unfortunately, in a dynamic environment such as the job shop, as soon as the schedule is released to the shop, it is immediately subject to random disruptions which may render the initial schedule obsolete (Wu and Storer 1990). It is susceptible to many disruptions like these and rescheduling includes machine breakdowns, delay in material arrivals, cancellation of orders, penalty over orders, opportunity loss etc.

Most rescheduling is similar as the machine breakdown problem as it involves uncertainty of larger order, and the down machine time period is significant with respect to the time horizon considered. The disruption nature can be different and scale can be large or small. Rescheduling refers to the process of generating new optimal solution upon the occurrence of a disruption. The initial parameters considers for rescheduling is same as the parameters of time t at the time of disruption. Because of the dynamic nature of most scheduling problem, this disruption problem is of practical importance equal to that of the initial scheduling problem and has, up until very recently, been neglected in production scheduling research (Svestka 1987).

The rescheduling problem in case of disruption can be considered as a constraints scheduling problem, the objective of which is to minimize the deviation. The scheduling problem is constrained by the technological or process planning constraints that determine the order of processing for the scheduling operations. This kind of problems can be solved using identifying the best mitigation strategy, which may include sourcing from various clients, finding new markets, backing up inventory etc. or such a problem two types of performance measures are indicated: measures of efficiency (e.g. make span) and measures of stability (i.e. deviation from the initial schedule).

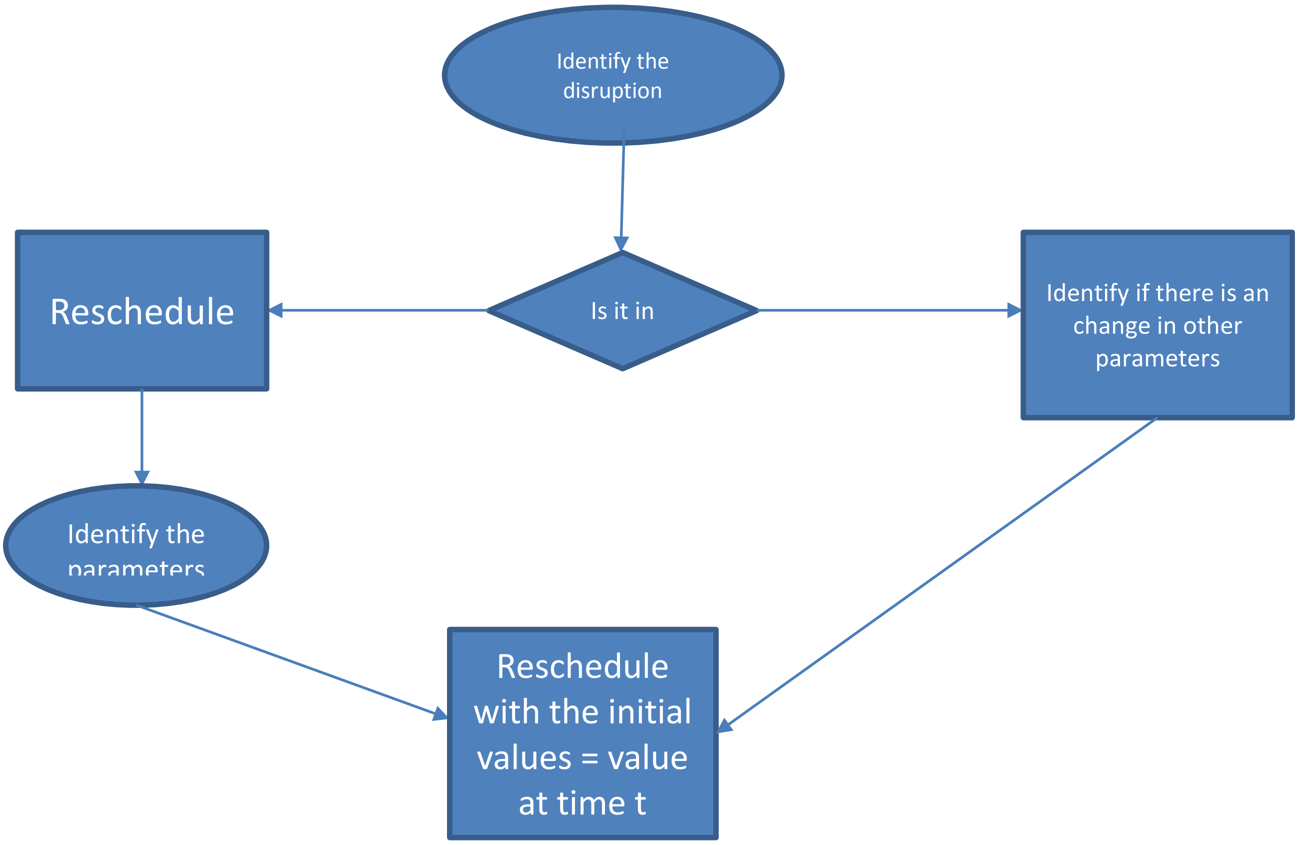

Figure 4.21: Rescheduling strategy to combat disruptions in supply chain

Rescheduling flow sheet allows us to monitor best available feasible solution at any given time for the remaining part. Considering increasing disruption due to weather condition, political instability and other natural or human causes, can lead to huge capital loss, and can be avoided through the smarter planning and resilient Supply chain.

Supply Side disruption:

In supply side disruption, we delay the arrival timings of one or more ships. This usually happens when there is disruption on one of the production site, or the country from where LNG is arriving is undergoing crisis. We know well in advance that there is disruption. This kind of disruption is known as ad-hoc recovery.

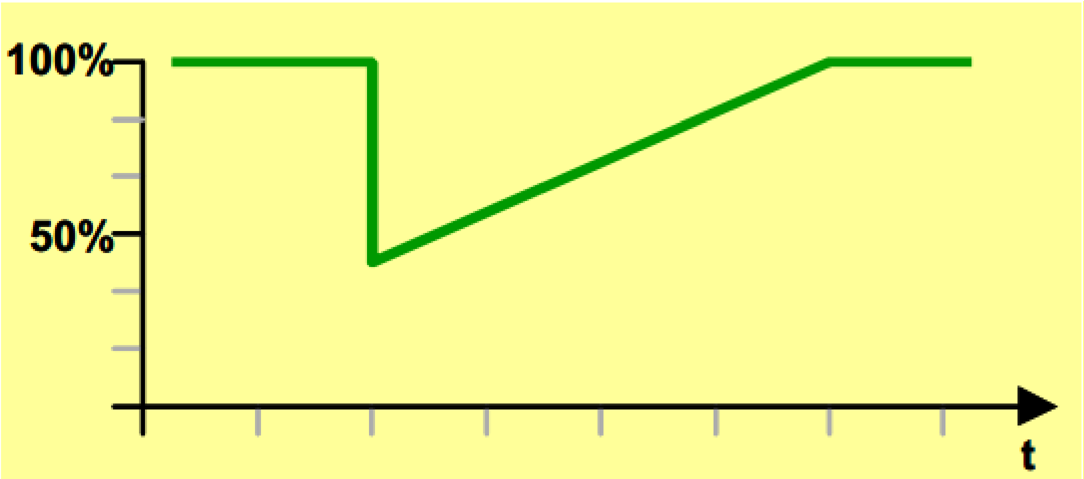

Figure 4.21: Ad-hoc recovery strategy for LNG supply chain disruption

One of the kinds of disruption when there is a sudden drop in the supply level and hence the company/terminal has to manage the deliver utilizing its inventory and minimizing the penalties that it occur doe to not mitting the demand.

We solve case study 2 in this chapter. We have done scheduling for unloading and supply based on the information provided. We add the disruption and we assume that at day 22, we are expecting some disruption and expect the arrival at time 27.

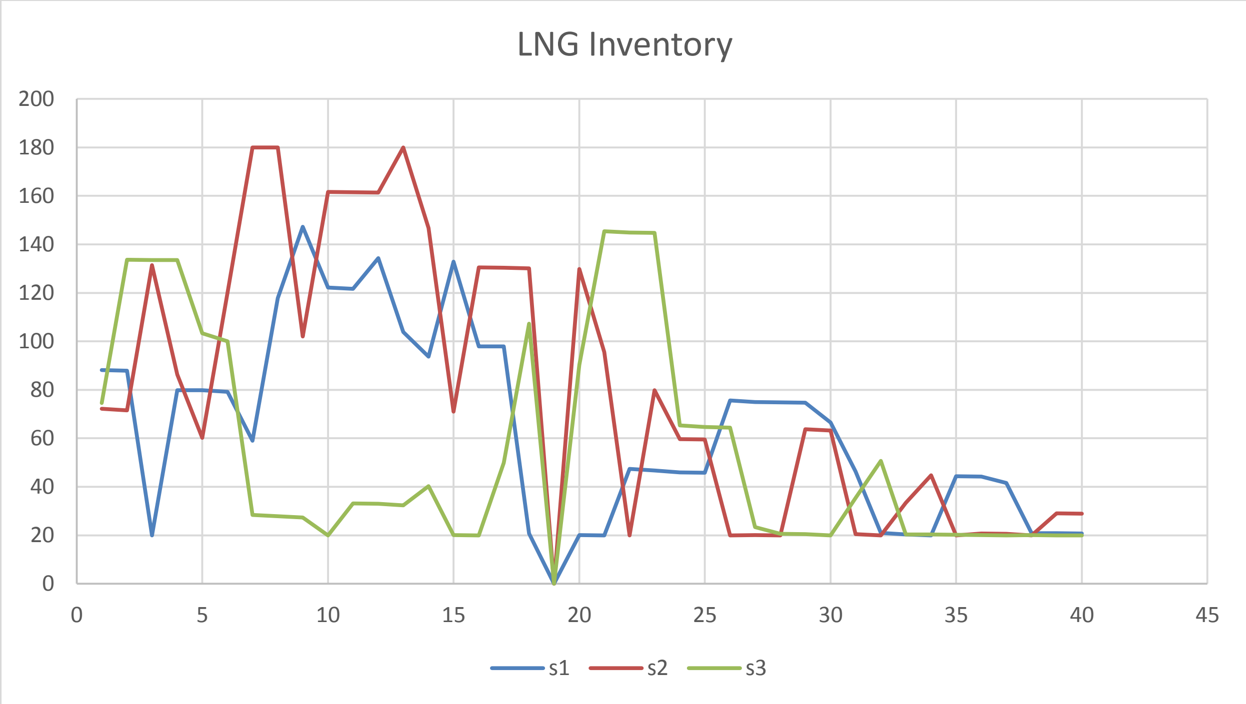

Figure 4.22: LNG inventory and supply chain disruption in case study 2.

The inventory position changes due to disruption. We can see there is a decline in the inventory time t=25, when we use the disruption.

4.5 Technical difficulty and challenges of the model

The model considers various aspects of the LNG receiving terminal. The decisions for planners and schedulers have been a complex task that involves decisions for different departments of the terminal. The model solves a part of everyday decision process, and also considers the part of mid-term planning.

There has been two major challenge of the model during the research:

1. Integrating qualitative contractual agreement: As discussed in section 2.3, there have been very literatures that deals with the quantitative assessment of contracts. The papers mostly deals with vendor selection using Arithmetic hierarchy process. The research approach through the model has been to model the contract that can helpful in decision making, analysing the loss or opportunity loss, and possible gain due to short term contracts. The model only considers the basic part of the Take-or-pay contracts. However there are several other kinds of contracts clauses such as FOB, Delivery ex-ship etc.
2. Planning horizon time: The time of planning horizon is solved for 40 days. However, the planning for LNG supply and demands are set months in advance. To get the solution for longer planning horizon is computationally challenging, as the binary variables increases exponentially.
3. Boundary condition infeasibility: To integrate several interdependent units of logistics in the model is computationally challenging. There has been several cases where it violates the boundary conditions, mainly inventory or contracts. To model that, the criteria has been relaxed with penalty.

4.6 Limitations of the model

Scheduling model developed in chapter 3 considers various processes of LNG receiving terminal. Section 4.1-4.3 solves three case studies and discusses the solution. The solution of optimization models gives the several optimal decisions such as starting time of unloading, its volume, starting time of output parcel, inventory positions, Linepack storage, regasification capacity utilizations, delivery, penalty occurred, and demurrages. It also discusses about the contracts and maximizing the profit from contracts. However there have been several aspects that could have been addressed to make the overall organization-wide decisions:

1. Uncertainty modelling: Model doesn't consider the uncertainty arises either due to delay in LNG shipping, or LNG demand fluctuations.
2. LNG liquefaction terminal supply profile: LNG supply profile, with time and volume is deterministic. However this is also a part of decision that have to be considered by the terminal owner. In real life, the time of arrival is arranged by integrating in the model as decision variable.
3. Process optimization: The various units at the terminal such as vaporizer, recondensor, compressor, pumps etc. should be integrated in the model for keeping it at steady state profile.
4. LNG quality: LNG quality is also important factor that is challenge to model. The model becomes non-linear and it will be computationally challenging to get the global optimization for long term planning horizon.

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