UNDERSTANDING LNG SUPPLY CHAIN & REGASIFICATION TECHNOLOGIES

A FINAL PROJECT REPORT

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CERTIFICATE

This is to certify that project report on **"Understanding LNG Supply Chain & Regasification Technologies"** submitted to **University of Petroleum & Energy Studies**, Dehradun by **Gaurav Sharma & Manishit Tewari** in partial fulfillment of the requirement of the award of degree of **Bachelor of Technology in Applied Petroleum Engineering**, session (2003-2007) is a bonafied work carried out by her under my supervision and guidance. This work has not been submitted anywhere else for any degree or diploma.

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ABSTRACT

LNG is a proven gas monetization option that has grown over the past 30 years from a 3 MMTPA industry in the early 1970s to 106 MMTPA industry in 2001. Even so, LNG today accounts for only about 6% of the total natural gas consumed worldwide. The growth in LNG is forecast to remain strong in the coming decade. The ability of the LNG option to continue to compete with existing and emerging gas monetization options will depend on the industry's success in reducing cost throughout the LNG value chain and maintaining exceptional safety, reliability, and environmental performance.

This report reviews the different components of the LNG value chain from the gas field to the eventual consumer with emphasis on liquefaction plant and regasification terminal. The report addresses feed gas treatment, liquefaction process technologies, utilities and typical CAPEX for the LNG liquefaction facility. For regasification terminals, the report will describe off-loading systems, storage tanks, regasification process, vaporizer designs, safety issues and typical CAPEX.

The engineering of LNG liquefaction and regasification facilities is considered a mature technology. However, there are several developments that have or will lead to reduction in life cycle cost of these facilities making LNG a more competitive gas monetization option. These developments include large capacity LNG plants, use of large single shaft gas turbine drivers, all electric drives, and offshore LNG facilities.

Currently, there are at least 50 proposed new receiving terminals in various stages worldwide; more than 35 potential projects have been identified for the North American market alone. This report will address the key drivers governing LNG receiving facility design and will then examine key design issues for each of the main elements os such terminals. This paper primarily addresses the issues surrounding onshore terminals, but also in specific areas highlights the differences between an onshore and offshore facility.

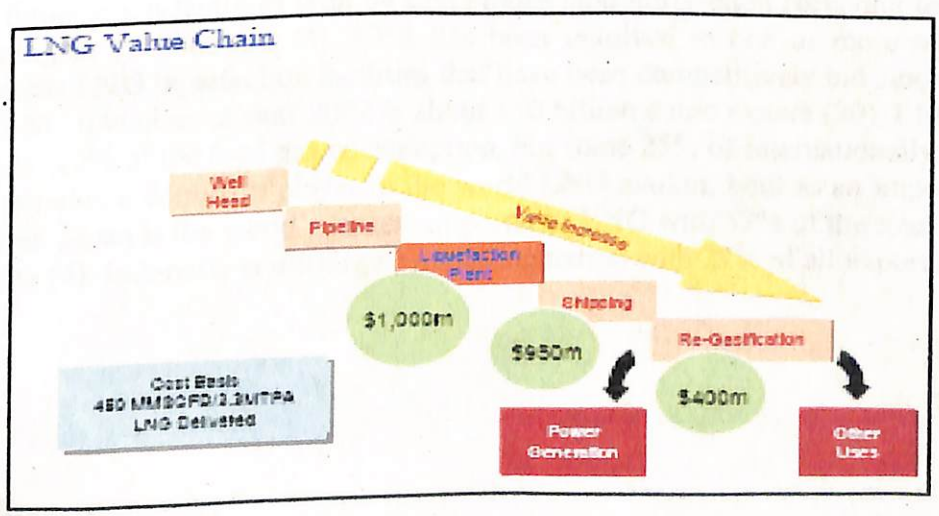
INTRODUCTION

Natural gas is the fastest growing primary energy source. Its use is projected to double between 1999 and 2020(1). Natural gas reserves are plentiful around the world, but many of them currently are too small or too remote from sizable population centers to be developed economically. Estimates of remote or stranded gas reserves range from 40 to 60% of the world's proven gas reserves (2, 3). This massive global gas reserve is largely untapped, and conventional means of development face logistical and economic barriers. Natural gas is of little value unless it can be brought from the wellhead to the customer, who may be located several thousand kilometers from the source. As natural gas is relatively low in energy content per unit volume, it is expensive to transport. The most popular way to move gas from the source to the consumer is via pipelines. For onshore and near-shore gas, pipeline is an appropriate option for transporting natural gas to market.

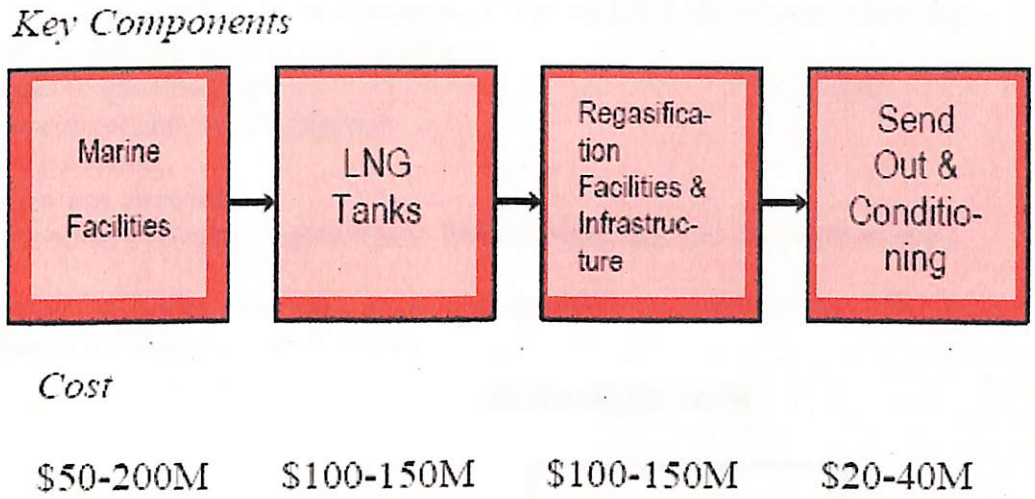
However, as transportation distances increase, pipelines become uneconomical; Liquefied Natural Gas (LNG), Gas to Liquids (GTL) and chemicals are more viable options.

LNG is an odorless, colorless, non-corrosive, non-toxic liquid that is produced when natural gas is cooled to a temperature of -161°C at atmospheric pressure. The liquid takes up about 1/600th of the volume of natural gas in its gaseous form. This enormous change in volume enables the gas to be transported economically over long distances as a liquid. Over the past 30 years, a considerable world trade in LNG has developed.

The cost for an LNG import facility varies, but can be US $ 400 million or more, and is dependent upon many factors. Nonetheless, it is a small component of the entire LNG value chain shown in Figure 1.



The major elements of an LNG import terminal and the range of costs for a 3 million tones per annum (MTPA) facility are shown in Figure 2.



Brief history of LNG

Godfrey Cabot submitted a patent for a barge to carry liquid gas in 1914. Although there is no evidence that this was ever built, it is the first mention of LNG in the US. As early as 1917, liquefaction was used in the United States for the extraction of helium. However, it was not until 1959-60, the Methane Pioneer, a converted cargo vessel, first demonstrated the technique of bulk LNG transport (by sea) by successfully and safely carrying seven LNG cargoes from Lake Charles, Louisiana in the United States, to Canvey Island, in the UK. The first commercial LNG plant in Algeria became operational in 1964 and exported LNG to Western Europe. In 2001, twelve countries have liquefaction facilities with 64 LNG trains, and thirty-eight receiving terminals are operating in 10 countries (4). KBR has been involved in one or more phases of all grassroots LNG liquefaction facilities that have been competitively bid since 1976. The total LNG traded as of year 2002 is about 150 billion cubic meters (20). LNG accounts for only 6.0% of the total gas consumption, but some 25% of internationally traded gas. Asia remains a dominant player in the world LNG market, both as an importer and an exporter. Japan is the world's largest importer of LNG with 53% of the total production capacity (4). Indonesia is the largest exporting nation with 27% of all exports.

THE LNG VALUE CHAIN

A typical gas monetization value chain option is shown in Figure 3.
The steps involved in the monetization of gas via LNG include the following:

- Gas Production and field processing
- Onshore gas treatment
- Gas conversion via liquefaction
- LNG shipping
- Receiving terminal
- End use as fuel (power generation, fertilizer industry, gas distribution, etc.)

All these activities must take place simultaneously in order for the LNG project to be viable as a gas monetization option.

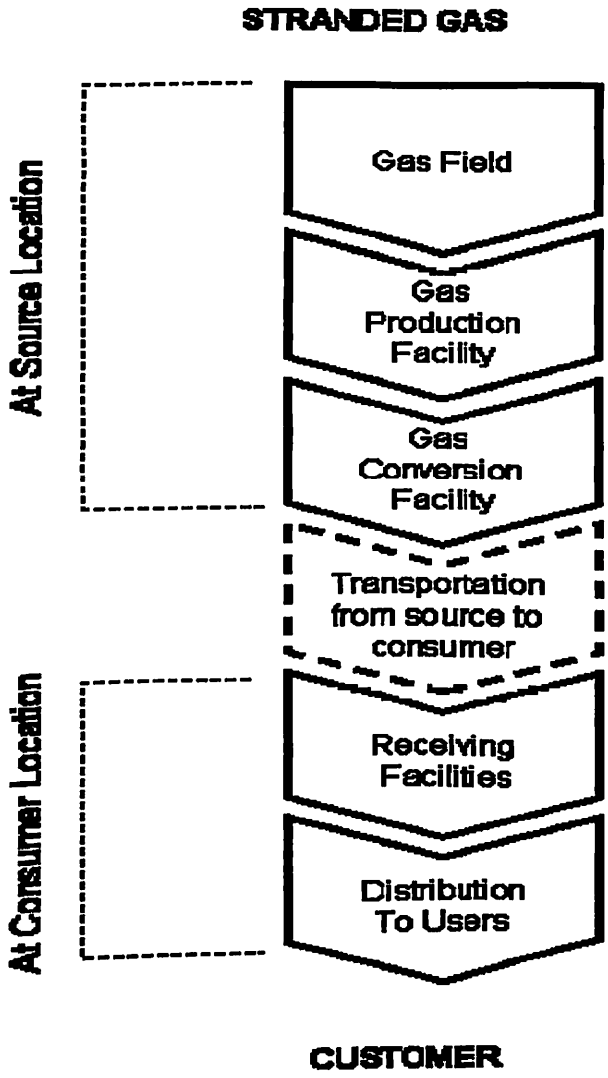


Fig. 3. Typical gas Monetization Chain

GAS PRODUCTION AND FIELD PROCESSING

The exploration and production of gas is the starting point for all gas utilization options. The source of natural gas feed to the LNG plant could be either associated gas or non-associated gas. Natural gas from gas fields typically is a mixture of hydrocarbons ranging from methane to heavier hydrocarbon molecules. Methane is invariably the dominant component. Ethane and heavier hydrocarbons are categorized as Natural Gas Liquids (NGL). Liquefied Petroleum Gases (LPG) components refer to a mixture of propane and butane. The quantity of NGL in the gas depends on the type of reservoir from which it originates. Gases with low NGL content are referred to as 'lean gas' while gases with high NGL content are referred to as 'rich gases'.

The gas production step includes some field processing, depending on the nature of the gas source and the requirements for pipeline transport to the liquefaction site. Typically, field processing is needed to avoid hydrocarbon liquid drop-out, hydrate formation or corrosion in the pipeline to the liquefaction site.

ONSHORE GAS TREATMENT

The gas from the reservoir may also contain components such as nitrogen, carbon dioxide and sulfur compounds. The feed gas has to be treated for removal of impurities before it can be liquefied. Hence, onshore gas treatment is required for the removal of NGLs and impurities to meet the specifications set by the LNG buyers as well as the requirements of the LNG liquefaction process. Typical LNG product specifications are listed in Table 1.

Table 1- Typical LNG Product Specifications

Component	Limits (maximum)
Hydrogen Sulfide	3 to 4 ppm
Total Sulfur	30 milligrams per normal cubic meter
Carbon Dioxide	50 ppm
Mercury	0.01 micrograms per normal cubic meter
Nitrogen	1 mol %
Water Vapor	1 ppmv
Benzene	1 ppmv
Ethane	6 – 8 mol %
Propane	3 mol %
Butane and heavier	2 mol %
Pentane and heavier	1 mol %
High Heating Value	≈ 1050 Btu/SCF (Europe and USA) > 1100 Btu/SCF (East Asia)

The onshore gas treatment typically comprises of gas reception facilities, acid gas removal & disposal section, gas dehydration, mercury removal and particle filtration.

GAS RECEPTION FACILITIES

This section is provided for the removal of liquids produced in the gas gathering system resulting from condensation as well as reduction in pressure of the fluid. The liquid may be either sent to a condensate stabilizer or to the fractionation section of the liquefaction plant. If a condensate stabilizer is provided, then the overhead gas stream from the stabilizer is sent to the feed gas for the liquefaction plant. The pressure of the LNG feed is adjusted in this section to meet the requirements of the liquefaction facility. If the pressure is lower than that required for liquefaction, then a compression system may have to be added. The pressure may have to be let down if it is higher than that required for the liquefaction plant. The selection of the pressure of the liquefaction plant is one of the key optimization parameters for the facility. Acid gas removal and disposal section. The purpose of this section of the plant is to remove acid gases (CO2 and sulfur containing components) from the feed gas. The extent of removal of these components is influenced by both the final LNG specification and the requirements of the liquefaction process. CO2 can freeze on exchanger surfaces, plugging lines and reducing efficiency. The feed gas is typically treated to achieve H2S content below 4 ppmv and a CO2 content of 50 ppmv in the feed gas. The total sulfur content is usually limited to about 30 milligrams per normal cubic meter.

There are various acid gas treatment processes available for the removal of H2S and CO2 from natural gas. These processes include chemical solvents, physical solvents, adsorption processes, and physical separation. However, only chemical solvents and physical solvents, or a combination of these two, have been used in existing baseload LNG facilities.

The composition of the inlet sour gas to the LNG plant could vary significantly from one location to the other. Optimal selection of the treating process is dependent on the type and level of impurity in the natural gas stream. The processes most widely applied for LNG plants include amine based processes ranging from conventional MEA to proprietary formulated solvents such as Shell Sulfinol; Union Carbide's Ucarsol and activated MDEA from BASF. Off gases from the acid gas treatment plant may be sent to a Claus unit for sulfur recovery provided that the volumes of sulfur that can be recovered are sufficiently large to justify the investment. When the quantity of sulfur is too low the off gas is often just incinerated or needs to pass though an acid gas enrichment process. More stringent environmental regulations may require further treatment e.g. with scavenger processes.

Figure 4 shows the application of various natural gas acid gas removal technologies in existing baseload LNG plants. Overall the Sulfinol and MEA process have been the most widely applied acid gas removal processes with approximately 70% of the installed LNG capacity. Due to its corrosive nature and high regeneration heat requirement, MEA is losing popularity. In contrast MDEA, usually applied with a proprietary activator to facilitate gas pickup, tends to be less corrosive and has lower regeneration heat duties than other amines. Thus the popularity of MDEA based processes, such as UCARSOL or aMDEA, is growing.

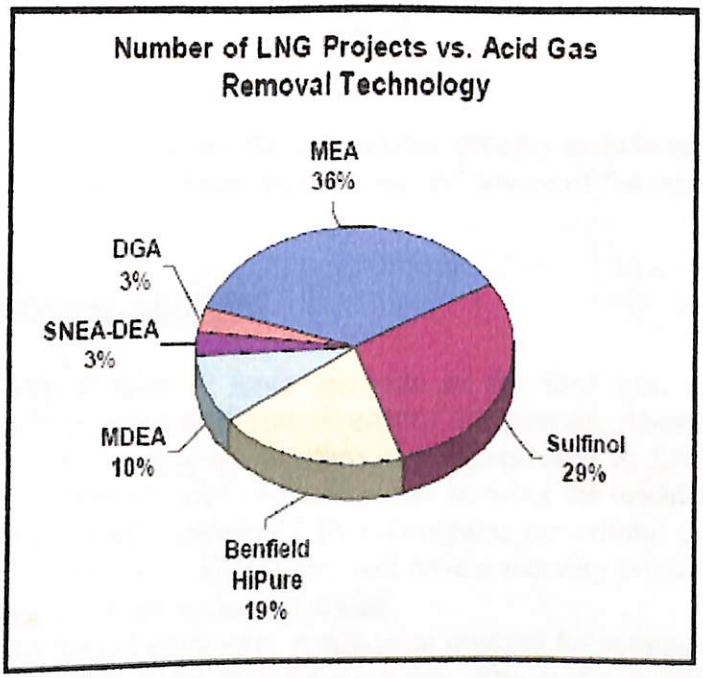


FIGURE. 4

DEHYDRATION STEP

The dehydration section removes water from the feed gas. Water vapor must be removed from the gas to prevent freezing in the liquefaction section of the plant that operates at cryogenic conditions. The gas is usually first cooled to a point above the hydrate formation temperature using air or water coolers and refrigerant. Free liquid water is separated and the remaining gas is fed to a molecular sieve adsorption unit for removal of water vapor below 1 ppmv. A typical dehydration schematic for the LNG plant dehydration scheme is shown in Figure 5.

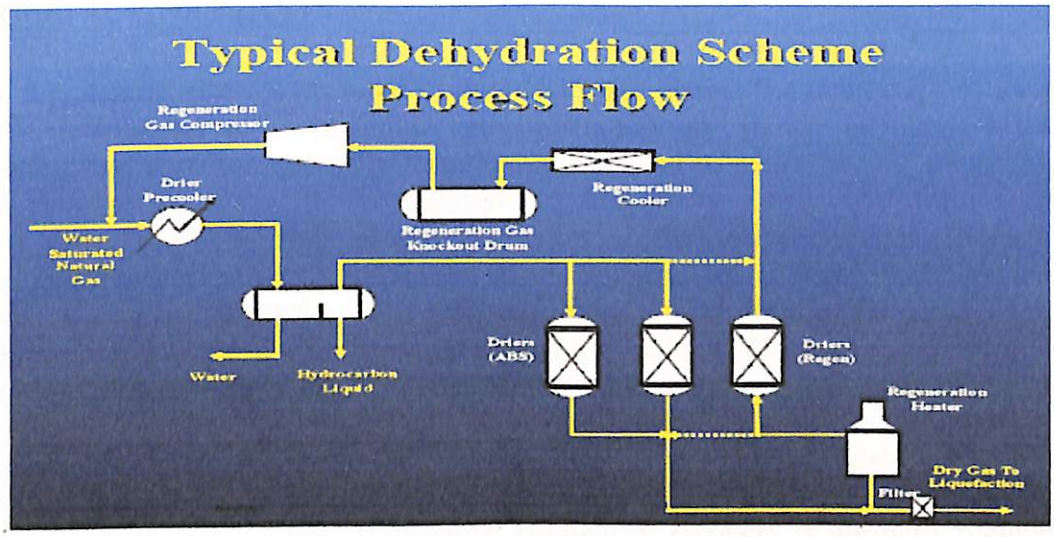


Figure.5

The key optimization options for the dehydration process include number of beds, type of bed regeneration, source of regeneration gas and source of the regeneration heat.

MERCURY REMOVAL SECTION

Mercury, generally present in trace amounts in the feed gas, attacks piping and equipment made from aluminum and aluminum compounds. Aluminum is a common construction material for low temperature exchangers used in LNG plants. Mercury must therefore be removed prior to the feed gas entering the cryogenic sections of the LNG plant to a maximum content of 0.01 micrograms per normal cubic meter (~0.013 ppb by weight). Almost every LNG plant will have a mercury removal vessel installed. The mercury removal vessel is usually placed
downstream of the dehydration unit. A common method for removal of mercury is by reaction with elemental sulfur to form a sulfide. The sulfur is supported on a high surface area solid carbon bed. This is a non-regenerative process and the spent carbon bed must be disposed to a land fill or is returned to the catalyst vendor for reclaiming.

PARTICLE FILTRATION

Filtering of the gas stream following the mercury removal unit is essential to prevent carrying particles into the liquefaction section of the plant and hence prevent equipment plugging.

LIQUEFACTION PLANT

The liquefaction plant is the heart of the LNG value chain. The main steps of a typical LNG liquefaction plant (including gas treatment) are shown in Figure 6. LNG liquefaction plants are generally classified as baseload or peak shaving, depending on their purpose and size (19). The discussion in this report is directed towards baseload LNG plants. The liquefaction process entails cooling the clean feed gas to -161oC using mechanical refrigeration. A refrigerant gas is compressed, cooled, condensed and let down in pressure through a valve that reduces its temperature by the Joule-Thomson effect. The refrigerant gas is then used to cool the feed gas. The temperature of the feed gas is eventually reduced to –161oC at which temperature methane, the main constituent of natural gas, liquefies. At this temperature all the other hydrocarbons in the natural gas will also be in liquid form. In the liquefaction process, constituents of the natural gas (propane, ethane and methane) are typically used as refrigerants either individually or as a mixture. Refrigerant component recovery is normally included in the LNG liquefaction facility. LPG and condensate may also be recovered as by-products. There are three main types of liquefaction cycles (cascade, mixed refrigerant, and expansion cycles). Most commercially available liquefaction processes are based on these cycles or a combination of these cycles. These processes include the Pure Component Cascade Cycle, Propane Precooled Mixed Refrigerant Cycle, Dual Mixed Refrigerant Cycle, Single Mixed Refrigerant Cycle, Mixed Fluid Cascade Process and others (5, 6). Table 2 summarizes the market share (based on tonnage of LNG produced) as of year 2001 of the different liquefaction processes.

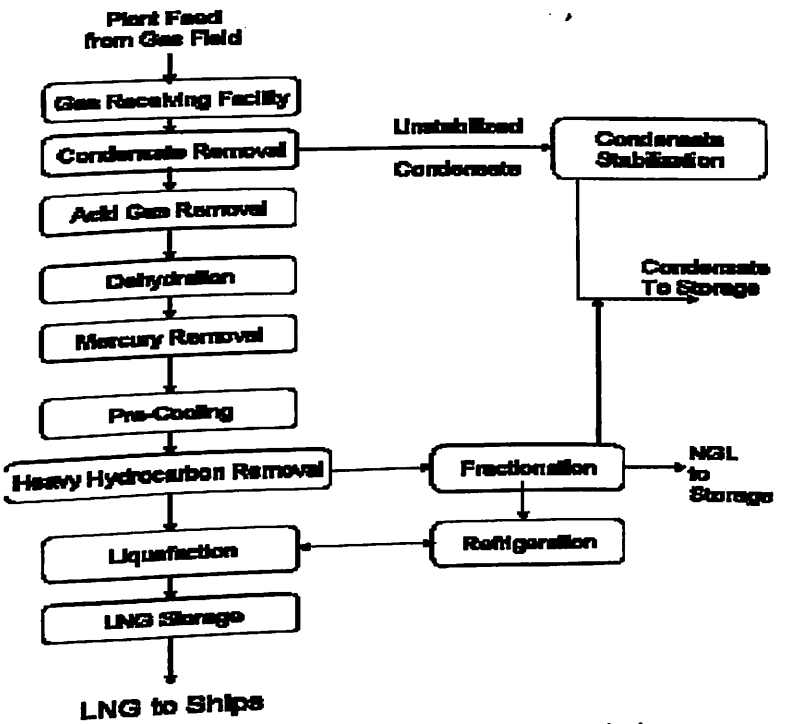


Figure 6. Components of Liquefaction chain

The liquefaction plant typically involves the following steps:
Initial cooling feed gas to remove heavier hydrocarbons. The first cooling step of the natural gas depends on the refrigeration process. Initial chilling is either provided by the first stage of the propane refrigeration cycle (cascade and propane precooled mixed refrigerant) or in the warm heat exchanger of the mixed refrigerant (MR) process. For this initial cooling the kettle or core-in-kettle type exchangers are often used if the temperature remains above the minimum for carbon steel application. At lower temperatures where special materials are required, plate fin (PF) or spiral wound (SW) aluminum exchangers are usually the economic choice.

LIQUID REMOVAL

Heavy hydrocarbon components i.e. aromatics and C5+ must be removed to prevent freezing at cryogenic temperatures. Lighter components such as ethane and LPG may be removed for one or more of the following reasons:

- to produce make-up refrigerant
- to control the heating value of the LNG product
- separate marketing of gas liquids

The feed gas stream is cooled such that heavy hydrocarbon components are condensed and then removed by vapor/liquid separation. The NGL is separated from the natural gas in a trayed vessel often called the Scrub Column. If the column is reboiled then it also functions as a demethanizer. Further fractionation of the liquid stream is generally carried out in the fractionation section described later.

TOTAL LIQUEFACTION OF NATURAL GAS

The dry lean gas is further condensed in the cryogenic exchanger, called the "Cold Box" or main cryogenic heat exchanger (MCHE), to an outlet temperature that will result in complete liquefaction of the feed gas. The general desire is to keep the liquefaction pressure as high as possible and the outlet temperature as warm as possible to improve liquefaction efficiency. Plate fin (PF) and spiral or spool wound (SW) exchangers are generally used for the liquefaction process since they allow a close temperature approach and are compact compared to the shell & tube exchangers. Figure 7 and 8 show the schematic of these exchangers. PF and SW exchangers have different tradeoffs in reliability, maintainability and cost.

Table 2 – LNG Liquefaction Processes as of Year 2001[1]

Process type	Percent of existing facilities
Propane precooled mixed refrigerant	90.4
Single mixed refrigerant	5.1
Pure component cascade cycle	3.5
Others	1.0

[1] Based on tonnage of LNG production

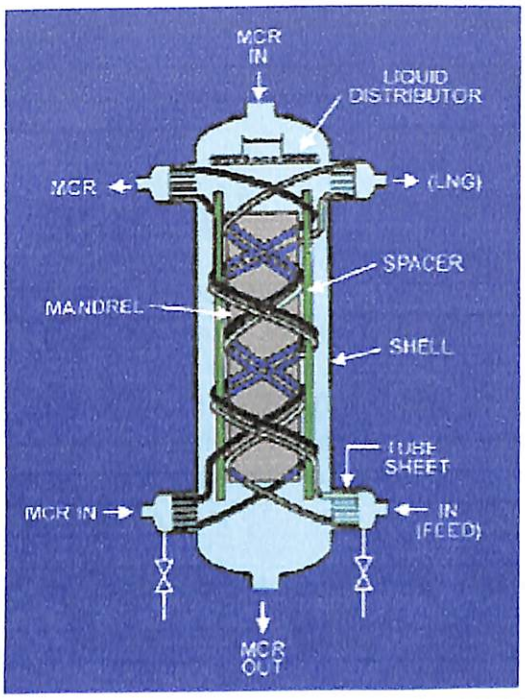


Figure 7 Spiral Wound Exchanger

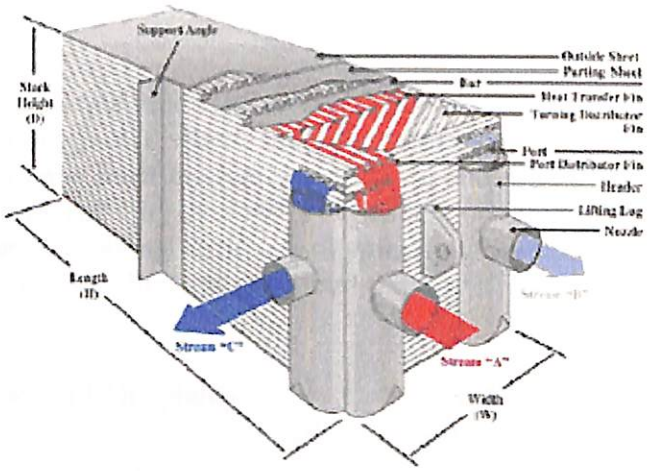


Figure 8 Plate Fin Exchanger

THE END FLASH OR NITROGEN REJECTION SECTION

Figure 9 shows a schematic of the end flash system. After liquefaction of the natural gas at high-pressure the LNG pressure needs to be reduced close to atmospheric before entering the tank. Unless the LNG is sub cooled, there will be high vapor generation in the tank that would have to be recompressed by the boil off gas compressor. An end flash is usually required if the nitrogen content in the LNG is above 1%. The end flash also removes methane with the nitrogen. The end flash section can be a simple flash drum or a reboiled trayed column. The column concentrates the nitrogen and reduces the methane loss from the LNG.

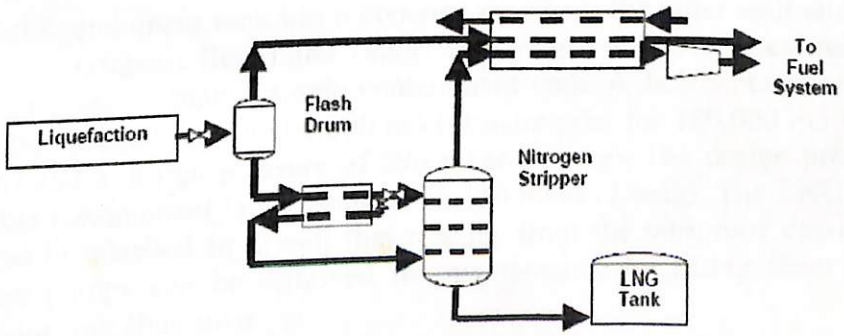


Figure 9 – Schematic of end flash system

LNG send out and storage. Following liquefaction and end flash section, the LNG is pumped to storage by the LNG rundown pump. The LNG is stored near atmospheric

pressure in tanks with a design pressure between 180 and 270 milli bar. Tanks can either be above ground, bermed or "in-ground" types. Above ground tanks are commonly used at base load

LNG PLANTS

In-ground LNG tanks are used (if appropriate) at some receiving terminals as they can be spaced closer together, which is an important factor where land for terminals is limited. Over the past several years, tank sizes have been gradually increasing and are now approaching 200,000 cubic meters. Total tank capacity at a site is dependent on the shipping traffic between the base load plant and receiving terminals. Typically a base load plant will have sufficient storage for at least one shipload and three days of LNG production.

Three types of tank containment systems are used in LNG plants

A single containment system comprises a double wall tank where only the inner wall is capable of containing the refrigerated liquid. The inner wall is typically 9% nickel steel that is self-supporting. This inner tank is surrounded by an outer wall of carbon steel that holds perlite insulation in the annular space. Single containment tanks are surrounded by a dike or containment basin external to the tank, either of which provides secondary containment in the event of failure.

The double containment system is arranged such that both inner and outer walls are capable of containing the refrigerated liquid. In the event of leakage from the inner tank the outer tank will contain the liquid. Excess vapor will not be contained. The outer concrete wall adds to the tank cost but less land is required because the diked area is eliminated.

A full containment tank has a concrete roof over the outer wall and the outer wall can contain cryogenic liquid and vapor. The weight of the concrete roof permits a higher design pressure than a single containment tank. A full containment tank may have a nominal capacity up to 160,000 m3 (designs exist for 180,000 m3 but none have been built) and a design pressure of 290 mbar (4 psig). The design pressure of single and double containment tanks is closer to 140 mbar (2 psig). The LNG loading pumps are normally installed in a well that reaches from the tank roof down to the tank floor. These pumps can be removed for maintenance by lifting them out onto the roof, without tank shutdown.

LNG LOADING

LNG is pumped from the storage tank to a LNG ship via a loading jetty. LNG plants are preferably located near deep water for LNG ship berthing. This would avoid overly long and costly jetty facilities. The currently popular ship size (between 135,000 and 140,000 m3) requires 50 ft (15 m) of water depth. At some plant locations the jetty needs to be extended several kilometers to reach this depth, contributing significantly to the plant cost. The LNG is loaded to the ship via the loading line and loading arms. The loading rate is driven by keeping the ship loading time as short as possible and by the cool down time of the ship tank material. This results in two pipelines in the low 20 inch range or one line about 30 inches. The lines are kept cold during the time when no ship is being loaded by circulating a fraction of the plant rundown to the jetty head and back to the tank. The liquid is transferred onto the ship through loading arms that have swivel joints, allowing limited ship movement during LNG transfer before automatically disconnecting. A common loading arm size for LNG service has a 16-inch opening with a loading capacity of about 5000 m3/h each. Two or three liquid loading arms are required depending on hydraulics of the system. One additional arm is dedicated to vapor that is displaced and generated in the ship and returned back to the tank to fill the vapor space.

THE FRACTIONATION SECTION

Figure 10 shows a typical schematic for the fractionation section. NGLs are recovered from the scrub column and separated in a fractionation train consisting of a demethanizer, deethanizer, depropanizer and debutanizer. The demethanizer is required if the upstream scrub column is not reboiled and ethane is separately produced as a product. The demethanizer overhead vapor returns to the feed gas stream for liquefaction or is sent to the fuel gas system.

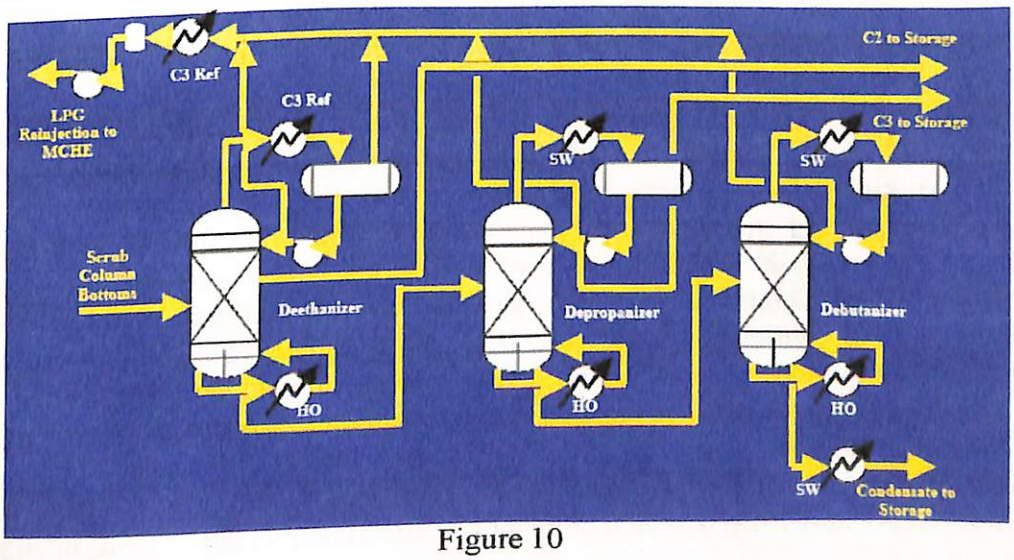


Figure 10

The deethanizer overhead can be returned to the natural gas liquefaction, up to a specified limit. Unless there is an external ethane demand, ethane can be used as plant fuel or be added to the LNG. A side draw from the column top section is taken as liquid ethane to the refrigerant make-up system. This stream does not require stringent distillation, if the make-up refrigerant is being mixed with methane and propane anyway. The bottom stream however has to be very lean on ethane if the downstream depropanizer produces refrigerant grade pure propane (99.5%).

Propane and butane are recovered as liquids from the total condensers of the depropanizer and debutanizer columns. These liquids are either used for refrigerant make up or sent to product storage to be exported. The bottoms stream of the debutanizer is condensate that can be mixed with the condensate from the upstream section or marketed separately as a gasoline component.

A key parameter in liquefaction plant design is the operating pressure. Higher operating pressure reduces the refrigeration load; however the pressure has to remain sufficiently below the cricondenbar (the highest point of the phase envelop, or the highest pressure where two phases are still possible) to allow vapor/liquid separation.

If the composition of the feed gas is such that the NGL can be retained in the LNG without infringing product specifications or causing operational (freezing) problems then the feed gas can pass through the LNG plant at the supercritical pipeline pressure. This improves the efficiency of the liquefaction process and simplifies the LNG plant by eliminating NGL recovery and its liquid handling facilities. However, this operation does not allow recovering refrigerant make-up fluid without a more complex expander compressor inclusion and requires importing refrigerant.

Higher liquefaction pressure results in a more efficient liquefaction process. Also, for a fixed shaft power availability, the higher pressure allows a higher outlet temperature from the main exchanger which results in a richer or heavier mixed refrigerant (MR) that increases the throughput. Refrigeration. All baseload liquefaction processes use mechanical refrigeration, in which heat is transferred from the natural gas through exchanger surfaces to a separate closed loop refrigerant fluid. The circulating refrigerant provides the necessary cooling. The specific power required is a key indicator of the refrigeration process efficiency. A variety of processes are available and the process selection is influenced by several factors. Some of the key factors include specific capital cost ($/tonne per year of LNG),thermal efficiency, heat exchanger type, proven operability and reliability, operating flexibility, process simplicity, available plot, efficiency, refrigerant make-up, cooling medium, project schedule and compressor drivers. Another factor in process selection for a given capacity target and site is that one process might provide a better fit for the selected refrigerant compressor drivers than another. Table 3 shows the number of refrigerant circuits in some of the commercially available liquefaction processes. Mixed refrigerant Processes

Table 3 – Refrigerant Circuits in liquefaction processes

Number of refrigerants	Pure refrigerant processes	Pure and mixed refrigerant processes	Mixed refrigerant processes
One	BHP, APCI		Pritchard, Linde, APCI
Two		APCI, Shell	Shell, APCI, Axen
Three	Phillips, APCI		Linde/Statoil

The key differentiators between the various liquefaction processes:
- The number of refrigerant system circuits
- The type of refrigerant(s)
- The type of exchanger(s)
- Compressor and driver type and size

The number of refrigerant circuits increases the process complexity requiring more compressors and drivers. Generally speaking, the differences in thermodynamics between the refrigeration processes are minor compared to the differences in equipment options.

The main components of the refrigerant system are the compressors and their drivers. The available drivers are:
- Steam turbines
- Gas turbines
- Electric motors

Each one of the driver types has certain advantages and disadvantages which are required to be evaluated for the specific project under consideration. The typical factors affecting compressor driver selection are equipment cost, plot area, utilities, efficiency, maintenance cost and experience/comfort level and emissions. The compressor driver types commonly used in LNG service are the industrial Frame sizes(Frame 5, 6 and 7). The aircraft derivative gas turbines, such as LM2500, LM6000and Rolls Royce, are more compact and efficient but no actual operating experience as mechanical drivers in LNG base load service is available. However, their smaller size will be a significant advantage for floating LNG plants, where space is crucial.

Although many steam turbine drivers are installed in existing plants, all new grassroots plants in the last 10 years are equipped with gas turbine drivers. Another driver type is the electric motor, which has the highest reliability if redundant electric power is available, but no LNG plant has been built exclusively using motor drivers .

LNG SHIPPING

Traditionally, shipping can be arranged either by the seller or the buyer of LNG. In cases where shipping has been arranged by the buyer of LNG, the buyer has entered into a charter agreement with the shipping company and the contractual arrangements protect the interests of the buyer of LNG.LNG is shipped commercially in a fully refrigerated liquid state. The fundamental difference between LNG carriers and other tankers is the cargo containment and handling system. The combination of the metallic tank containment and insulation needed to store LNG are termed "containment systems".

There are two main types of containment systems; self-supporting tank and membrane tanks. Current LNG vessels have about 135,000 cubic meter carrying capacity(about 60,000 metric tons). Larger size ships up to 250,000 cubic meters are under consideration. The ship cargo is kept cool by evaporating a fraction of the cargo which is typically referred to as "boil off". The carriers either consume boil off gas or re-liquefy the gas and use diesel as fuel.

RECEIVING AND REGASIFICATION TERMINAL

The function of an LNG import terminal is to receive LNG cargos, store LNG and revaporize the LNG for sale (on demand) as gas. Odorant injection may be required if gas is to be exported via a transmission grid. A simplified process schematic for a LNG receiving terminal is shown in Figure 11.The LNG receiving terminal (sometimes called a "regas" facility) receives liquefied natural gas from LNG ships, stores the LNG in storage tanks, vaporizes the LNG, and then delivers the natural gas into a distribution pipeline. The receiving terminal is designed to deliver a specified gas rate into a distribution pipeline and to maintain a reserve capacity of LNG. The amount of reserve capacity depends on expected shipping delays, seasonal variations of supply and consumption, and strategic reserve requirements. Strategic reserves are needed when the terminal may be called upon to replace another large source of gas from either a pipeline or another receiving terminal on short notice. The LNG terminal consists of the following.

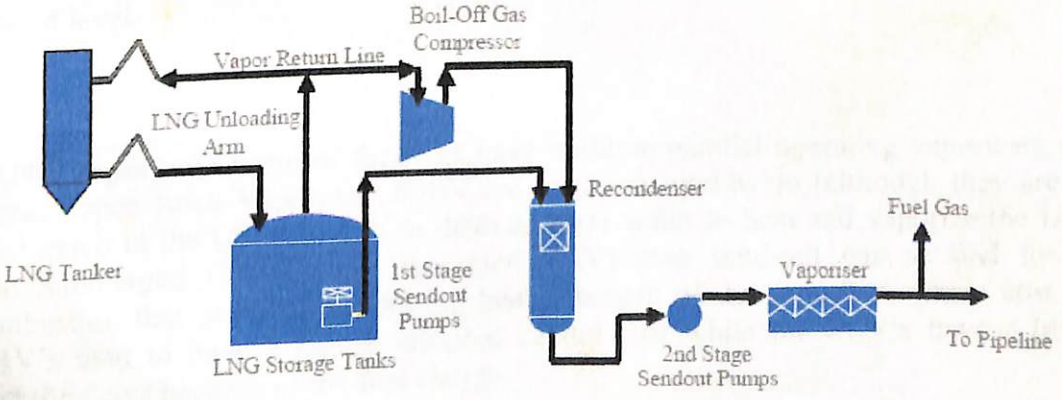


Figure 11 – LNG receiving terminal simplified process schematic

• **LNG unloading system** including jetty and berth LNG is transferred to the onshore LNG tanks by the ship pumps. The unloading facility is often designed to accommodate a wide range of tanker sizes from 87,000m3 to 135,000 m3. The liquid unloading rate from the ship is usually10,000 m3/hr carried out by eight to ten pumps. It takes approximately 12-14 hours to unload one 135,000m3 ship. From the ship, the LNG flows through the unloading arms and the unloading lines into the storage tanks. The unloading lines can be two parallel pipes, each24 or 26 inches diameter or a single larger pipe with a small recirculation line.

• **LNG storage tanks** Two or more above ground tanks are generally installed for receiving and storing LNG, though terminals have been built with a single tank. To reduce cost, designers try to minimize the number of tanks and maximize the amount of storage per tank. If the facility has only one tank then send out and LNG unloading will be from the same tank, but this does not cause any operating difficulties. The types of tanks are similar to the ones used for liquefaction facilities. The decision to use single, double, or full containment is based on applicable codes, cost, land availability, and sometimes protection from external events such as vapor cloud blast pressure, and missiles or small aircraft.

VAPOR HANDLING SYSTEM

During normal operation, boil-off vapor is produced in the tanks and liquid-filled lines by heat transfer from the surroundings. This vapor is collected in the boil-off header that ties into the boil-off compressor suction drum. A Boil-Off Gas (BOG) recondenser may also be provided which serves to recover the BOG as product and provides surge capacity for the pumped out LNG second stage pumps. During ship unloading, the quantity of vapor in the tank outlet increases significantly .During upset, extreme turndown or emergency conditions, vapors may be generated within the terminal that exceeds the capacity of the pipeline compressor. If this occurs the vapors vent to the atmosphere through an elevated vent stack or flare for safe disposal. In the case of a vent stack the vapors are preheated if necessary to avoid flammable mixtures near ground level.

• **LNG vaporizers** terminal facilities have multiple parallel operating vaporizers with spares. Open Rack Vaporizers (ORV)are common worldwide (although they are not used much in the US terminals to date) and use water to heat and vaporize the LNG. The Submerged Combustion Vaporizer (SCV) uses send-out gas as fuel for the combustion that provides vaporizing heat. Because of the seawater system cost, the ORV's tend to have a higher installed capital cost while the SCV's have a higher operating cost because of the fuel charge.

• **Open Rack Vaporizers** Seawater in an open falling film type arrangement vaporizes LNG passing through the tubes . The water falls over aluminum panels and collects in a trough below before discharging back to the sea. The seawater first passes through a series of screens to remove debris before entering the intake basin. Raked bar screens provided in the inlet of the intake basin remove floating debris and provide protection vertical seawater and pumps in the basin. The pumps are located in individual separate bays within the intake basin. At the inlet of seawater pump bay, a traveling band screen may be provided for further removal of suspended solids to prevent blockage or damage to the open rack vaporizers. The larger single ORV units installed are for a gas send-out rate of approximately 200 to 250 mmscfd.

• **Submerged Combustion Vaporizers** These vaporizers burn the natural gas taken from the send-out gas stream and pass the hot combustion gases into a water bath that contains the heating tubes for LNG. The largest single SCV units installed are for a gas send-out rate of approximately 150 MMSCFD.

• **In-tank and external LNG pumps** Several low-head LNG send-out pumps are be installed ineach LNG storage tank. These pumps operate fullysubmerged in LNG and are located within pump wells orcolumns, which allow easy installation and removal. The pump wells also serve as the discharge piping from the pumps, and are connected to the tank top piping. These LNG pumps will deliver the design LNG send-out flow and circulate LNG through the ship unloading piping to keep the lines cold between ship unloading times. A 500m3/h (2200 gpm) pump supplies the LNG for about 250in-tank pumps is around 8 barg. The send-out gas is usually injected into a high pressure gas distribution system of approximately 80barg. For this pressure, multistage send-out pumps(booster pumps) are required. The pumps are high-head and take LNG from the first stage pump discharge and boost up the pressure to the vaporizers at the required.

• **Supporting utilities**, piping, valves, control systems, and safety systems. The following facilities are required to provide utilities to the LNG receiving terminal and support its operation:

- Seawater intake, outfall and pumping system for ORV
- Electric Power
- Firewater
- Foam System
- Plant water
- Plant and instrument air
- Nitrogen (storage and vaporizer)
- Emergency power generation

- Effluent treatment, including sanitary and contaminated rain water
- Diesel oil supply for firewater pumps and emergency generator
- Ship facilities (e.g. Bunker C fuel, etc.) and ship supplies, lubricants, etc., might also be required.
- Control room, substations, maintenance, warehouse, administration, and guardhouse
- Infrastructure (roads, fencing and buildings)

Receiving terminals to date are expected to operate close to365 days per year and have spared equipment to achieve this availability. In at least one case a terminal operated over three years continuously and was shutdown only for a statutory inspection. In spite of the traditionally high terminal availability, spare equipment can be eliminated and cost savings achieved if the gas consumers can tolerate interruptions in the send-out supply. Protection of the LNG tanker during navigation, berthing, and unberthing and while docked and unloading is a major design consideration. In addition, the transfer of LNG is an important operation, and special measures are usually taken by the terminal designers to protect the general public as well as the employees at the terminal. Such measures include emergency shutdown systems, spill containment, loss prevention equipment and anti-pressure surge protection of piping.

LNG terminal layout and site selection are typically based on the following ship parameters:

• 130,000 to 135,000 m3 capacity, having an overall length of up to 310 m, width of 46 m, and fully loaded draft of11.6 m. The net delivery unloading rate into the receiving terminal is approximately 10,000 m3/hr. There are smaller ships (down to less than 60,000 m3) which can also be included in the jetty design basis, but the industry trend is towards larger ship sizes.
• The minimum water depth at the jetty head is 15 meters.

Three codes and standards that apply for US LNG receiving terminal safety are:
NFPA 59A

US Code of Federal Regulations 33 CFR 127

US Code of Federal Regulations 45 CFR 193
These codes and standards specify the basis for minimum distances to shipping lanes, public meeting places, bridges, and residences. The distances are based on dispersion of vapor clouds to below flammable levels in the event of a spill, and to protect the general public from high thermal radiation levels in the event of fire.

CAPITAL COST AND ECONOMIC SCREENING DATA

A Pipeline is the most commonly used option for monetizing gas. About 75% of the gas that is traded internationally is moved via pipelines. However, the costs of delivering large quantities of gas by pipeline rise rapidly with distance. At some point,

it becomes more economical to transport the gas as LNG. Several comparisons of pipeline and LNG have been published (14, 15). LNG is competitive with pipelines for distances greater than 2500 km. Compared to pipelines, LNG has the benefits of modular buildup and few border/right of way issues. This section covers information that is useful in the evaluation of LNG as a gas monetization option. Although worldwide gas inputs for LNG facilities are relatively cheap (based on large and easily producible reserves), the processing and transportation equipment is highly specialized and capital intensive requiring billions of dollars of investment for each new LNG project through the value chain. The costs to produce and supply LNG can be divided among the major elements that make up the supply chain each of which is necessary to implement a successful project.

GAS PRODUCTION FACILITIES

In view of the high cost of liquefaction, shipping and regasification of LNG, it is essential to have low-cost feed gas to produce LNG competitively. Gas production cost typically varies from 0.25 $/MMBtu to over1.0 $/MMBtu. A cost of production below 1.0 $/MMBtu(preferably below 0.5 $/MMBtu)is desirable to make the LNG option economically viable.

In addition to low cost gas, proven reserves of natural gas to support the liquefaction facility for a period of 20 to 25years is required. Approximately 1 TCF of feed gas is required to produce 0.8MMTPA of LNG for 20 years. Hence, a 5 MMTPA of LNG production will require a gas field size of about 6 TCF.

If the natural gas production yields significant quantities of condensate or natural gas liquids, the revenue from the petroleum co products may offset some of the natural gas production cost. While extracting the condensate and liquids from the feed gas is usually profitable, the loss of volume associated with this should be recognized. Base load liquefaction plant with storage and export facilities. Typically, the liquefaction plant is the most expensive portion of the LNG chain. The cost of the facility depends on several site specific factors as well as size of the plant. Figure 12 shows the specific cost of various recent LNG project as published by Merlin Associates (16).

This cost varies from 200 to 400 $/tones/year of LNG capacity. The trend in LNG plants is towards larger train sizes as a way of achieving economy of scale. Currently, single train sizes in the range of4.5 to 5 MMTPA are under construction and larger train sizes up to 7.5 to 8 MMTPA are being proposed. The LNG liquefaction plant size can be determined by the gas field size. LNG projects are inherently capital intensive with the liquefaction plant being the largest cost component accounting for about 50% of the total cost of the LNG chain (7). Typical capital cost breakdown of a grassroots LNG liquefaction facility is shown in Table 4

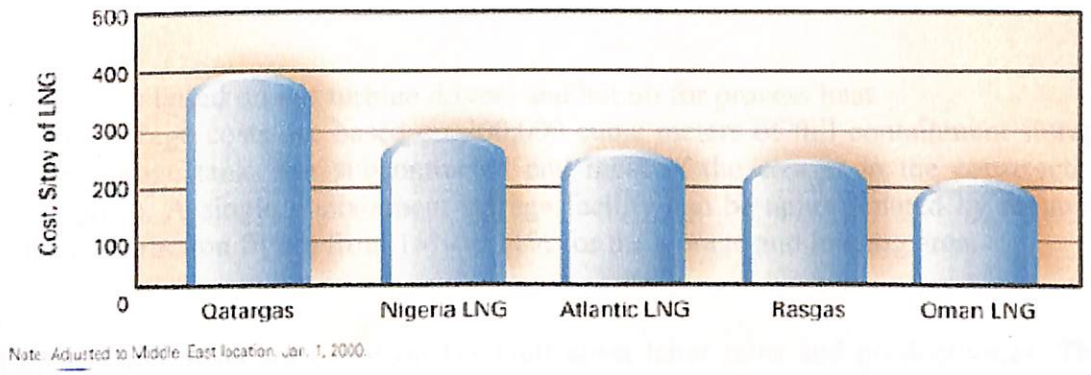


Figure 12 – LNG Plant Specific Cost[16]

Table 4 - Approximate LNG Plant Cost Allocation (Basis: 2 train - 6 to 7 MMTPA Grassroots Plant)

Percent of Total Cost	Gas Treatment	Liquefaction/ Ref-rig/N2 Reject	Fractionation	Utilities & Offsites	LNG Storage & Loading	Total
Equipment	4	14	1	10	1	30
Bulk Materials	3	7	1	5	4	20
Construction	4	6	2	8	15	35
Misc*	1	5	1	4	4	15
Total	12	32	5	27	24	100

*Misc category includes insurance, home offices costs, material freight & transport, etc.

•Base CO2 concentration is 4%. For 10% CO2 the total Gas Treatment unit cost increases from 12% of total to about 16% and utilities increase from 27% to 30%.

• Fractionation cost is based on no LPG extraction. To extract propane and butane products, increase fractionation cost by 10% (from 5% to 5.5%) and add $100-150 per cubic meter of storage (double metal wall, single containment) or $200-300 per cubic meter for full containment storage (concrete outer wall). The costs per cubic meter are

for the storage tanks only and do not include any additional marine facilities, fire protection, etc.

- Utilities are based on gas turbine drivers and hot oil for process heat.
  LNG storage costs are based on 200,000 cubic meters of full containment storage (the storage tanks are subcontracted and most of the cost is in the construction category). A single containment storage facility can be approximated by reducing the construction figure from 15% to 11% for the storage and loading area.

- Construction costs are based on US Gulf coast labor rates and productivities. This category includes design/supply/erect subcontracts, supply/erect subcontracts, direct hire erection, field staff, and indirect support facilities. The capital cost of the liquefaction facilities is dependent on several factors such as plant location, size of plant, site conditions, quality of feed gas, etc.

The contribution of the liquefaction plant cost to the cost of delivery of LNG ranges from 1.5 to 2.0 $/MMBtu (8). The cost of a liquefaction plant is a significant component of the cost of the LNG chain. Hence, cost reduction of the liquefaction facility is an important issue. The thermodynamics of the liquefaction processes are well developed. Thus, further advances and cost reductions in this industry come from refinement of equipment to better service(make more efficient) the liquefaction process and/or supporting infrastructure (utilities). KBR has been active in the LNG field since its inception and is working closely with the industry to achieve this cost reduction objective. There are several publications that discuss cost reductions in liquefaction plants (9, 10, 11, and 12).

LNG TANKER SHIPS (TRANSPORTATION)

Every LNG project typically requires dedicated LNG ships. The number of ships required for an LNG project depends on the distance between the liquefaction plant and the receiving terminal. LNG transportation cost increases linearly with distance. The LNG carriers are typically designed for speeds of17 to 20 knots. The number of ships required for 1 MMTPA can be quickly estimated by (6):

Number of ships = (one way distance in nautical miles/5000 +0.25)
The fleet of tankers for a LNG project is a noteworthy portion of the total cost of the LNG chain. The typical LNG carrier can transport about 125,000 - 138,000cubic meters of LNG, which will provide about 2.6 - 2.8billion standard cubic feet of natural gas and cost about $160million (17). The number of ships and hence the cost of shipping is dependent on the distance between the liquefaction facility and the market. A typical contribution of the shipping cost to the cost of delivered LNG is about 0.5 to 1.2$/MMBtu (8).

IMPORT TERMINAL WITH STORAGE AND REGASIFICATION FACILITIES

The cost of an LNG receiving terminal is highly dependent on the selected site. A typical cost distribution is provided in Figure 13. Factors that change the above breakdown are many and include the following:

• Marine Conditions: The cost of the jetty depends on the jetty length. If the marine contour is nearly level the jetty length increases, in some cases dramatically. Dredging may also be an option in which case the capital cost lowers but the operating cost increases. The cost of the jetty also depends on submarine soil conditions. Submarine soil that can not support much weight results in longer piles that either work with friction or go all the way down to bedrock. Another major item that may be needed is breakwater if the site has an unprotected shoreline. The breakwater site frequently has high waves

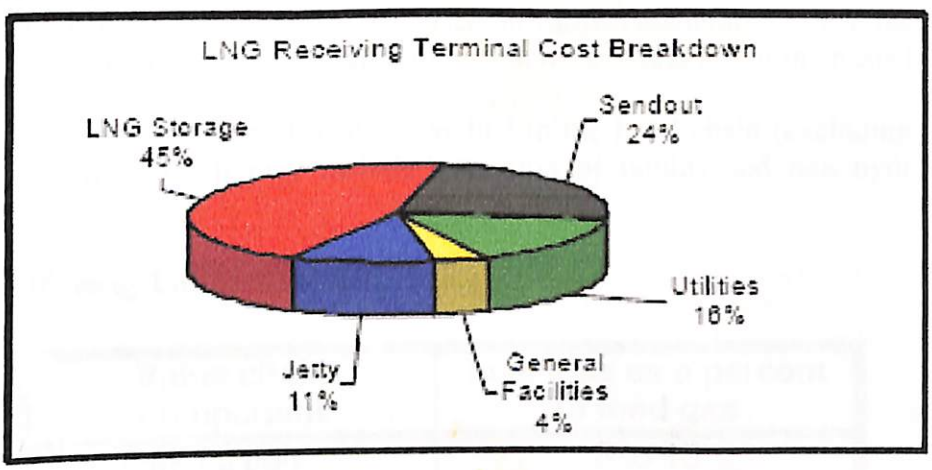


Figure 13 – Receiving Terminal Cost Breakdown

•Onshore Soil Conditions: The ideal soil allows the use of spread foot foundations. If the soil does not support enough load for spread foot foundations there are several other options, but all add to the project cost.

• Storage type: Single containment storage is the least expensive type of storage; single containment storage takes more land and may not be practical at some sites. Double containment costs about 1.45 times the cost of single containment, and full containment storage is 1.7 times the cost of single containment (13).

• Power generation on site: One of the costliest utilities in a receiving terminal is power generation, however many facilities import power from the local grid to reduce capital cost expenditure.

• Labor: Construction labor is a major cost factor that varies widely from site to site. Unlike liquefaction terminals, receiving terminals are often located near population

centers. If this is true then it may be possible to obtainmuch of the required skilled labor locally. Using local labor significantly reduces cost when a camp is not needed to house the construction force. In those cases it may still be necessary to provide transportation to and from the site, but this is still a small expense compared to a camp.

The receiving terminals with tanks, vaporization equipment and utilities contribute approximately 0.3 to 0.4 $/MMBtu to the delivered price of LNG. These costs are highly dependent on specific site conditions and design practices (especially forthe design of the storage tanks).

In summary, the cost components of delivered LNG fall in the range as indicated below:

- Gas production facilities 0.5 to 1.0 $/MMBtu
- Baseload liquefaction facilities 1.5 to 2.0 $/MMBtu
- LNG transportation 0.5 to 1.2 $/MMBtu
- Receiving terminal 0.3 to 0.4 $/MMBtu

The numbers listed above are indicative based on various assumptions. The readers are encouraged to refer to the original paper for a detailed explanation of the basis for these numbers (8).

Table 5 summarizes the loss of feed gas as fuel in the LNG chain (excluding the gas production facility, which may include extraction of liquids and non hydrocarbon gases).

Table 5 – Efficiency Losses in the LNG Value

Value chain component	Fuel loss as a percent of feed gas
Gas liquefaction	8 to 10
Shipping	Depends on shipping distance[1]
Regasification	2 to 2.5

[1] About 0.15 to 0.20% of the cargo is consumed per day of travel during which the tanker travels about 480 nautical miles.

The large capital cost involved with each element of the LNG value chain imposes certain characteristics to the LNG business:

- Projects typically are undertaken by large organizations having familiarity with the business.

- Successful project typically involves cooperation of the host government (where the gas is located), owner of the liquefaction facility, the consuming organizations and a range of specialized organizations like shipyards, financiers, ship operators, EPC contractors and technology licensors.

• Projects typically have long gestation periods and involve extensive feasibility and engineering studies to reduce the risk associated with the large investment.

• Projects are not likely to proceed unless the developers receive some assurance that they will be able to earn an acceptable return on investment. Projects typically involve long term sale purchase contracts at a price that supports debt servicing.

LNG RECEIVING FACILITY DESIGN

The key drivers that govern the design and cost of an LNG receiving facility are:
• Location
• Regulatory requirements and design codes to be used
• Site characteristics (soil conditions, earthquake potential, marine bathymetry, environmental conditions)
• Availability of local infrastructure including labor
• Capacity of the facility
• Operating issues: reliability and availability required for the facility
• Source(s) of LNG supply and characteristics
• Gas send-out characteristics
• Safety and security considerations
• Owner's risk requirements

LOCATION

To date, all LNG import terminals have been constructed onshore. Due to local opposition ('not in my back yard' or NIMBY), lack of undeveloped land remote from population, cost of land, and general permitting obstacles, it is very likely that some of the new terminals under consideration will be constructed offshore, especially in the United States. While not solving all problems, this should reduce NIMBY and permitting obstacles. These facilities could either be founded on the seabed (gravity base structures or GBS) or floating with anchor lines to the seabed. GBS facilities would be located in waters less than 35meters due to construction techniques for the GBS, while the floating terminals could be located in water depths up to 1500 meters.

Figure 14 - A Typical Onshore LNG Receiving Terminal
Courtesy of Enagas



An artist's impression of a GBS solution is shown in Figure 15 and a floating solution is shown in Figure 16.

Figure 15. GBS LNG Terminal

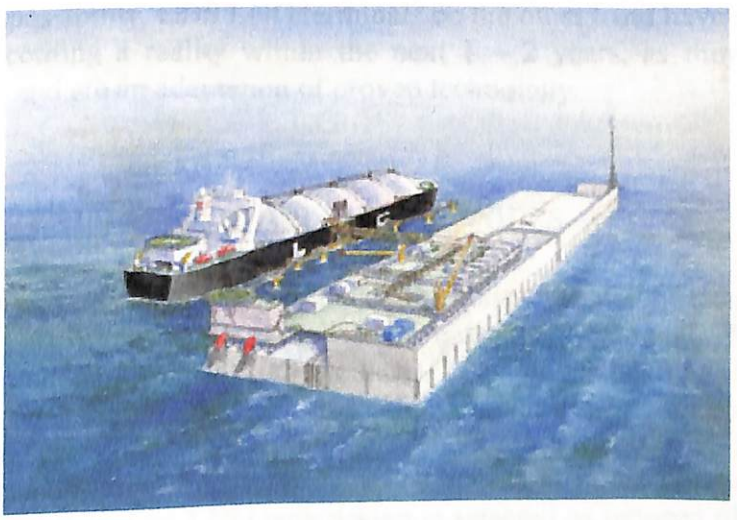


Figure 16 - Floating LNG Terminal



The primary outstanding issues associated with offshore terminals compared to an onshore terminal are the secondary containment of LNG in the tanks, and safety issues associated with the facilities, LNG storage, and personnel being located in close proximity for either the GBS or floating facility options. The floating facility option, due to the potential high relative movement between the terminal and the LNG carrier, poses the added problem of the LNG unloading equipment, which has not yet been constructed, or satisfactorily tested in actual loading conditions. Proposed solutions are in advanced design stages by several companies, but which Owner will be the first to buy such a unit and the additional acceptance by regulatory authorities make it a more problematic and thus more distant possibility. GBS LNG terminals on the other hand have a very good probability of becoming a reality within the next 1 – 2 years, as they are similar to onshore terminals and are an adaptation of proven technology.

REGULATORY REQUIREMENTS AND DESIGN CODES

A key issue for an LNG receiving terminal is the codes that will be used for its design. In general, North American terminals will use the National Fire Protection Association(NFPA) code 59A (2001) as the basis. Locations outside North America will generally use the Euro norm (EN) code1473 (1997) as the basis. Both codes are similar, but treat LNG storage tank types differently. The different types of LNG tanks are described in detail later in this report. This can be of benefit in the design of the facility, particularly if full containment LNG tank design is selected as reduced plot plans can be achieved.

Other local and national codes will supplement these codes for the facility design. Several of the terminals presently under consideration are in countries with no such

existing facilities; thus, it is very important to have early discussions with the regulatory authorities to ensure a common agreement and understanding of the applicable codes.

One area of concern for an offshore facility is the lack of a generally accepted design code. These are being progressed by several independent agencies such as American Bureau of Shipping, Det Norske Veritas ,and others, but have not yet been agreed by all interested parties.

OPERATING ISSUES

The sparing, maintenance and staffing philosophy for the facility should be determined by the Owner in conjunction with both the regulatory authorities and the design engineers before commencing the design process. This will ensure that the facility's reliability, cost and impact on the local community are all evaluated as to the most practical and cost-effective solution during detailed design work.

The normal operating staff for an LNG terminal is 25–50,depending upon the location in the world. Thus, onsite housing would not normally be provided, though the proximity of local population will need to be assessed. This of course would not be the case for an offshore LNG terminal, which would be operated similar to a typical offshore production oil or gas platform, with personnel based on the facility. However, the shifts used and the necessity for overnight housing will depend upon the conditions and proximity to shore. The site would have maintenance and are house facilities, but again, the location of the facility andthe existence of third party facilities for maintenance of equipment must be carefully evaluated. An offshore facility would have maintenance primarily performed onshore.

SAFETY AND SECURITY

Safety and security issues have always been an important consideration for LNG receiving terminals, but in recent times have taken on an added level of scrutiny and importance. As these facilities are often remote from other areas, local support and required onsite staff must be addressed as well as physical design factors. The requirement for the facility to be located near navigable waterways makes the design that much more difficult and important to thoroughly evaluate. An offshore facility has advantages of being remote from the mainland, but also is far more approachable by any marine vessel. The use of exclusion zones and third party security measures are mandatory if facility security is to be achieved.

RISK

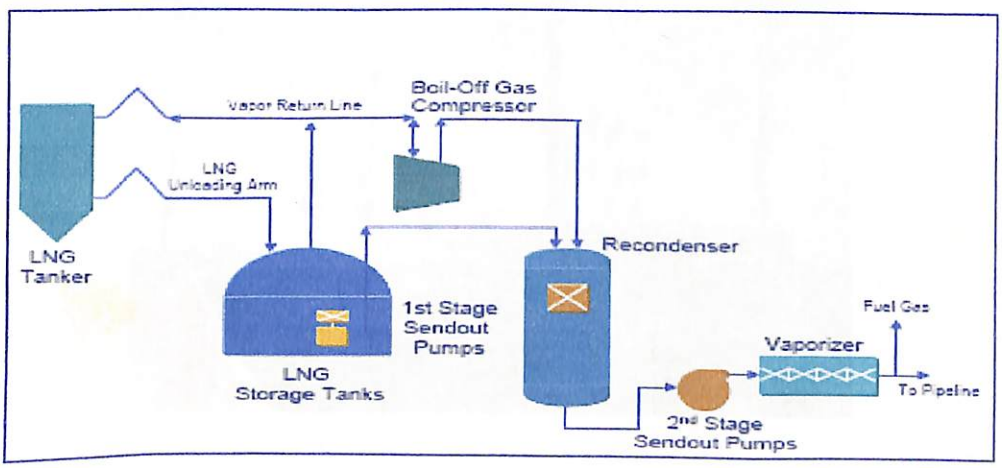
Another area to consider prior to starting design is the risk tolerance of both the Owner(s) and the regulatory authorities. This will depend upon the experience of all parties, good, bad or no experience, and can be mitigated as long as the design engineer achieves an early understanding.

KEY RECEIVING TERMINAL COMPONENTS

The key components of an LNG receiving terminal are:
- Marine facilities, including the LNG unloading system
- LNG storage tanks
- Regasification process including vaporizers
- Utilities and other infrastructure requirements

These are shown diagrammatically in Figure 17.

Figure 17 - LNG Terminal Key Components



The basic process for an LNG terminal is a very simple heat exchange. LNG is transported from producer to the terminal via ship, unloaded via loading arms (Figure 18, onshore or GBS, Figure19, offshore floating) and stored at approximately minus 160°C.Thus, a key characteristic of handling LNG is that significant parts of the facility will be subjected to severe cryogenic conditions. The LNG is then pumped under pressure to heat exchangers called vaporizers, where it is warmed to approximately 15°Cand in the process expands in volume 600 times. It is then sent out to users via a traditional pipeline grid system at 500 to1,200 psi, depending upon the final user (power plants will typically be 500 psi, traditional pipeline grid systems will be at800 – 1,200 psi).

MARINE FACILITIES AND LNG UNLOADING

A major cost item which can have a significant impact on the overall economics of the LNG terminal is the marine facilities, including the LNG unloading system. The key design variables of the unloading system are:

- Distance from ship to tanks
- Ship discharge pump capacity (typically 3 – 5 barg)
- Elevation of tanks

- Desired discharge rate
- Top versus bottom fill of LNG tanks
- Number of lines desired for reliability
- Hydraulic design of the line (water hammer)
- Structure design of the lines (bowing)

Figure 18 – Onshore or GBS Loading Arms



Figure 19 – Offshore Unloading Equipment for Floating Facilities



Courtesy of FMC

The availability of berthing, range of ship size desired and discharge rates tend to be the determining factors when positioning and sizing the unloading components. Depending upon the wave environment for the area, a breakwater may be required. A typical LNG carrier of 135,000 cubic meters (m3)is approximately 300 meters in length, 50 meters in width and has a draft of 11-12 meters and requires a minimum water depth of approximately 15 meters. Newer ships under design and discussion range up to 250,000m3 capacity. These ships are longer and wider than the traditional 135,000m3 ship, but have a similar maximum draft so that they can operate at a number of existing LNG terminals.

The marine facilities capable of providing shelter from waves can easily be the most expensive part of an LNG terminal, and can cost up to $200 million, depending on whether or not a breakwater is required.

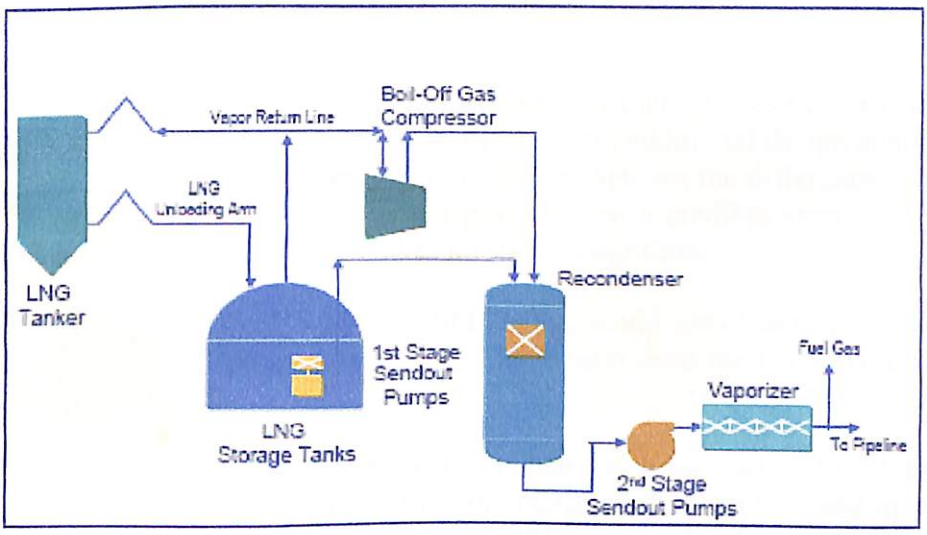
The size and desired frequency of the LNG ships will usually determine the number and capacity of the LNG storage tanks, the second most expensive part of an LNG terminal, and cost US $50-60 million per tank. Extensive shipping simulations will be required to optimize the number of ships and the quantity of storage tanks and to ensure that the availability of the facility and the robustness of the supply chain are not compromised. The requirement for a breakwater will depend upon the met ocean criteria, wave simulations and the availability of the unloading berth that is desired.

The necessity for a breakwater should be a key design issue and appropriate time and resources allocated to confirming the requirement and the effect on facility availability.

One of the key design considerations during operation of the LNG terminal is the management of LNG vapors arising during both unloading and while LNG is stored in tanks between carriers discharging LNG. The management of this vapor is critical due to both the value of the vapor and the elimination of any venting or flaring of the vapor that may be prohibited by environmental regulations. The vapor is produced as a result of the heat leak of the system during these operations and the LNG displacement during ship unloading.

A typical vapor management system diagram is shown in Figure 20.
Order of priorities for vapor disposal
1. Vapor return to ship
2. Vapor return to storage tank
3. Send-out with LNG
4. Pipeline compressor
5. Flaring

Figure 20 - Vapor Handling System



LNG STORAGE TANKS

LNG storage tanks designs are typically defined as:

- Single containment
- Double containment
- Full containment

Single containment tanks have only a single shell and use a secondary bund or dike to limit the spread of an LNG spill, double containment tanks have an outer shell to contain spills and full containment tanks have the added feature of a roof structure that will contain all vapors emanating from a spill for a limited period of time.

Tanks can be circular, membrane or self-supporting prismatic (SPB) in design. LNG tanks are primarily constructed with 9% Nickel steel inner tanks due to the cold temperature (-160°C) that they must withstand, but can also be constructed using stainless steel or aluminum. The outer tank can be either concrete or steel, depending upon Owner preferences and Regulatory Authority requirements. In addition, onshore tanks have also been constructed using the "membrane" type of liner over a concrete wall. All of these types of tanks have been used in various locations and are technically acceptable. They require different amounts of land, with the single containment tanks requiring significantly more land area to ensure safe separation to account for the effects of the safety analyses for both potential thermal radiation and gas dispersion events, and thus must be carefully analyzed.

In addition, single containment tanks cost approximately 30%less than full containment tanks and double containment tanks cost approximately 10% less than full containment tanks, so a careful analysis of land cost and tank cost must be performed. However, in some countries, the Regulatory Authorities have mandated the use of double

containment tanks at a minimum, so the decision may already have been made for the Owner. The applicable design code, either EN 1473 or NFPA 59A,will also have an impact on the layout of the facility tanks.

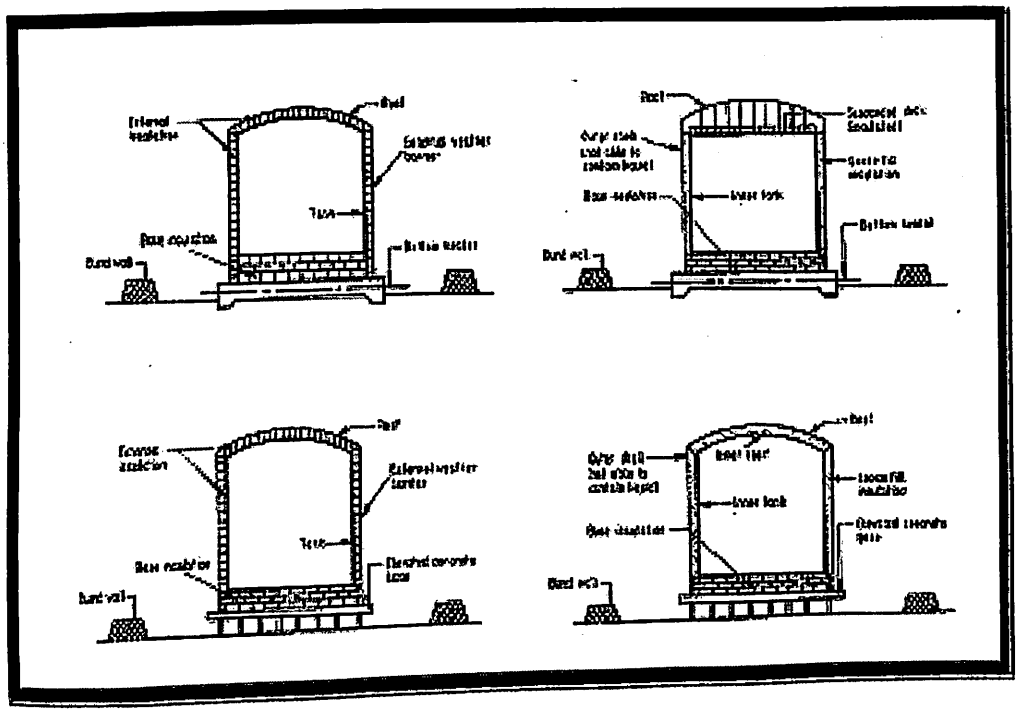
The primary difference between the two codes is that NFPA59A does not recognize any inherent difference between the types of tanks and additional design analyses must be performed to differentiate the designs; EN 1473 recognizes the difference – for instance, for a full containment tank, a fire is not judged to be a credible event and so does not have to be analyzed – NFPA 59A makes no such recognition.

Self-supporting prismatic tanks, or SPB tanks, could also bean option though none have been built for receiving terminals, but have been used for LNG carriers and so are technically acceptable.

Each of these solutions is very different in construction method and cost and are often mandated by regulatory authorities where the facility will be located and by the Owner's preferences. Other issues such as the amount of land available for the facility also have a significant impact on the choice of tank type.

Details for each tank option are shown in Figures 21 – 26.

Figure 21 – LNG Tank Design – Single Containment Tanks



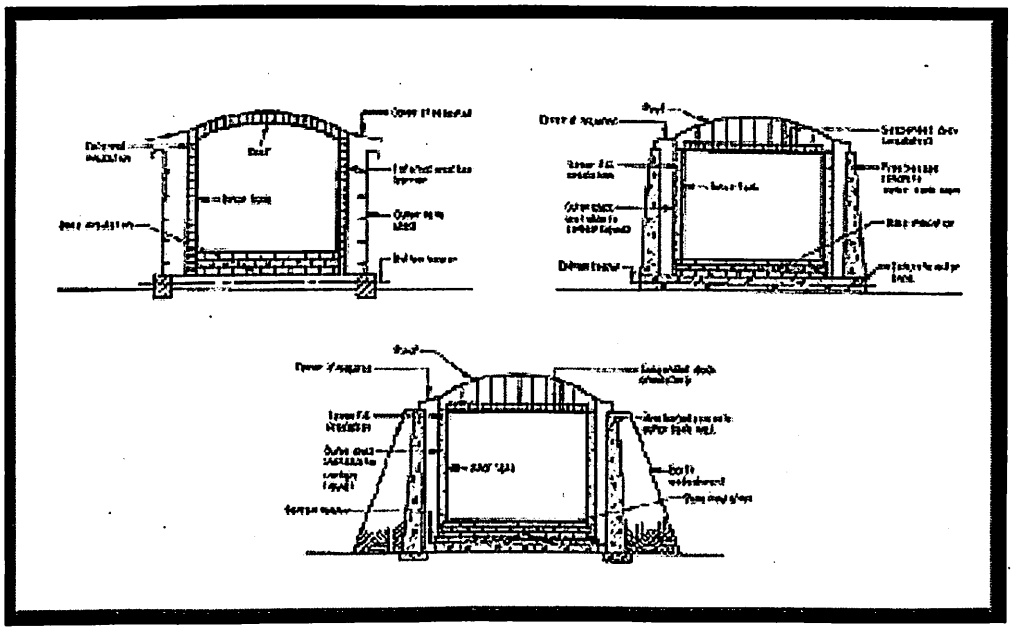


Figure22 -LNG Tank Design – Double Containment Tanks

Figure 23 – LNG Tank Design – Full Containment Tanks

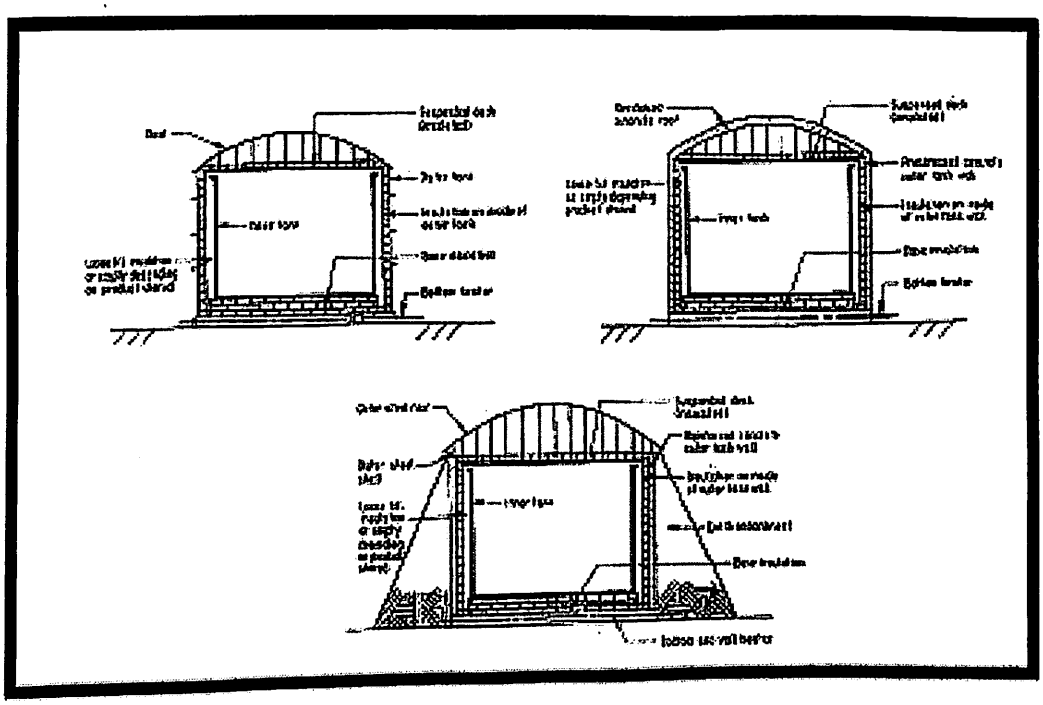


Figure 24 – LNG Tanks



Courtesy of Technigaz

Figure 25 - Cross-Section of 9% Nickel Tank

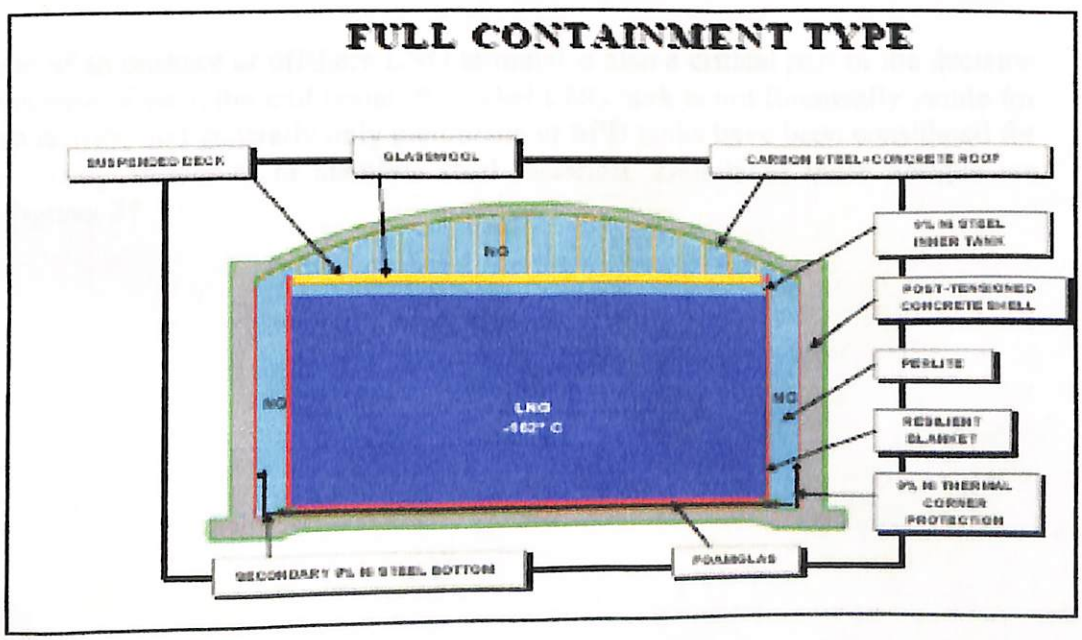
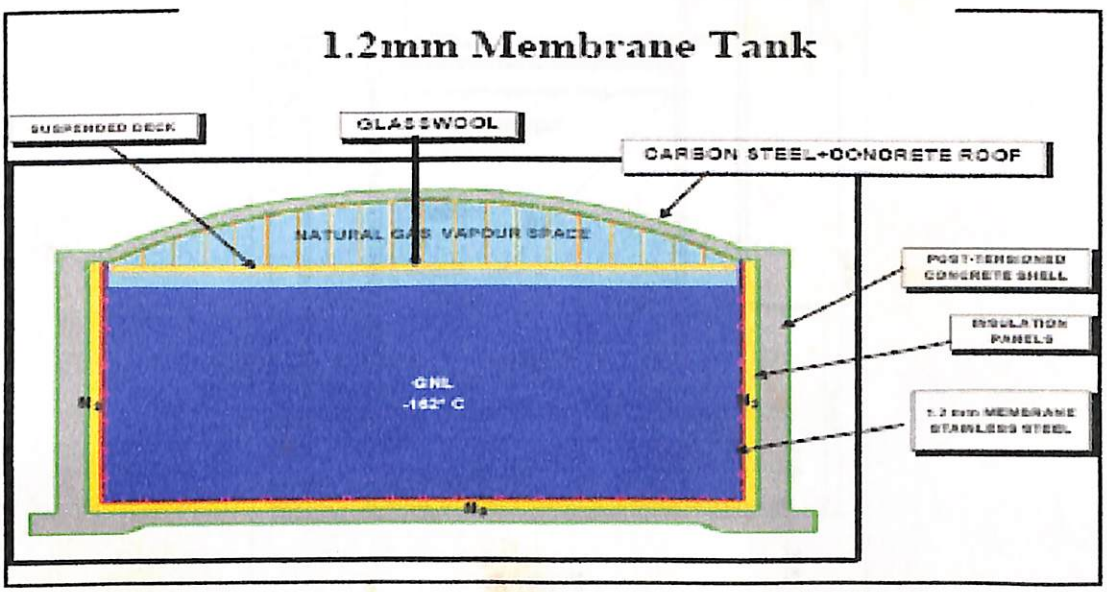
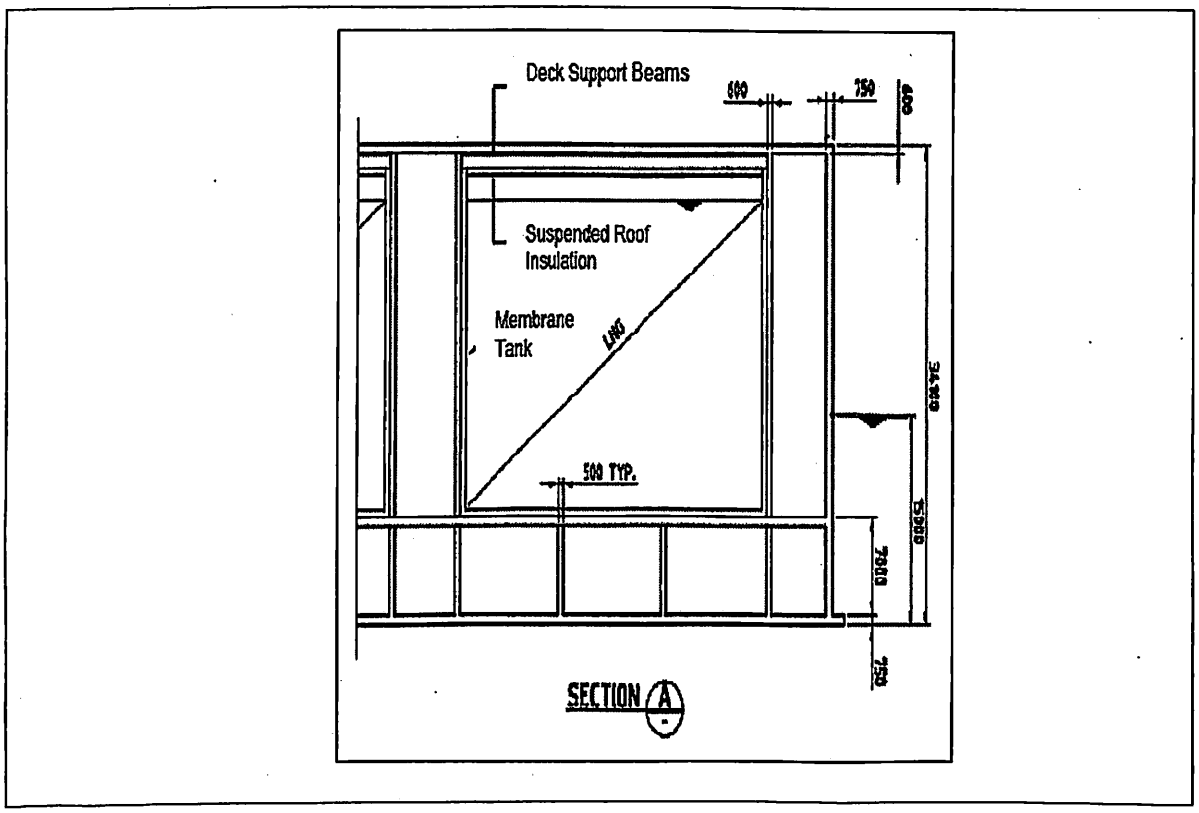


Figure 26 – Cross-Section of a Membrane Tank



The use of an onshore or offshore LNG terminal is also a critical part of the decision process. Because of cost, the traditional 9% nickel LNG tank is not financially viable for an offshore facility, and generally only membrane or SPB tanks have been considered for this design using aluminum or stainless steel materials. Details of these designs are shown in Figures 27

Figure 27 – Membrane LNG Tanks – Offshore



REGASIFICATION

The LNG is sent to the regasification section of the terminal by high-pressure send out pumps. These pumps provide all of the pressure required for the send out gas, thus avoiding more costly gas compression. They are typically centrifugal; multistage with submerged electric motors using an electrical system designed for hazardous areas and have a self-contained suction vessel. A typical send out pump and details of design are shown in Figures 28 and 29.

Figure 28– LNG Send-Out Pump Diagram
Courtesy of Ebara International

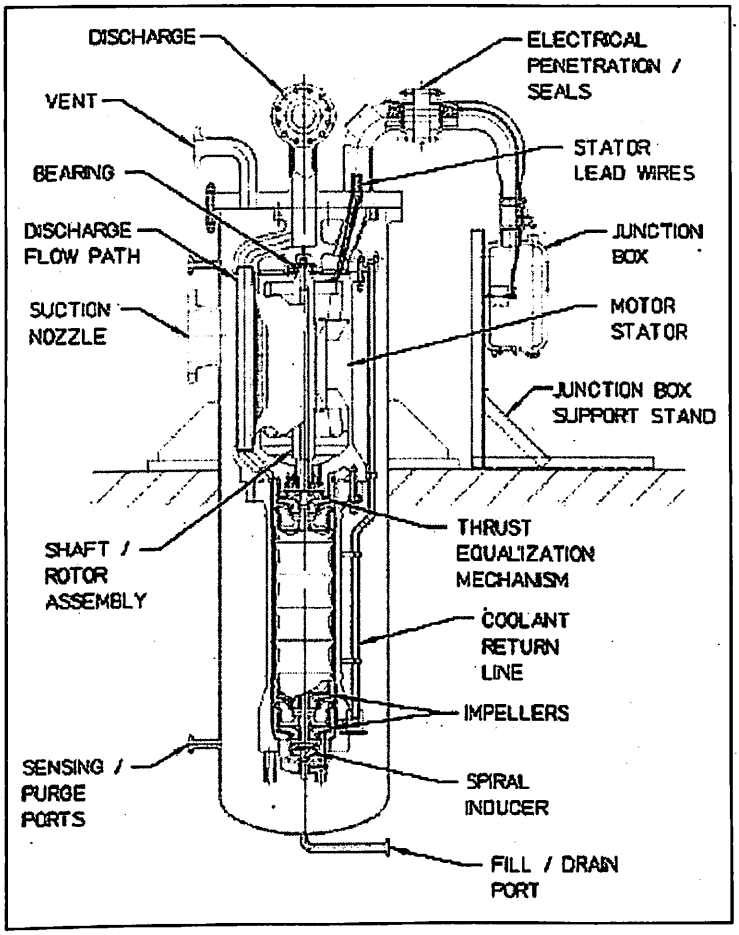


Figure 29 - LNG Send-Out Pump

Courtesy of Ebara International



The regasification or vaporization of the LNG can be accomplished via several methods. These are:

- Seawater heat exchangers, called open rack vaporizers (ORV)
- Warm water bath heat exchangers, called submerged combustion vaporizers (SCV)
- Combined heat and power heat exchanger systems (CHP)
- Intermediate fluid (offshore system)
- Other site-specific systems or combination of the above systems.

Each of the above types of vaporizers has advantages and disadvantages. A summary of each follows, and details of these units is shown below.

Open Rack Vaporizers (ORV)

- Higher capital cost
- Low operating cost
- Large quantities of seawater used (25,000 – 65,000m3 of water per hour, thus large seawater handling system required)
- Seawater quality is important (no heavy metals, low solids desired)
- Seawater is returned at 5–8°C cooler than intake, potential environmental impact
- No air emissions
- Easy to operate and maintain

These are shown diagrammatically in Figure 21 and an actual unit in Figure 22.

Figure 30 - Open Rack Vaporizer (ORV) Diagram

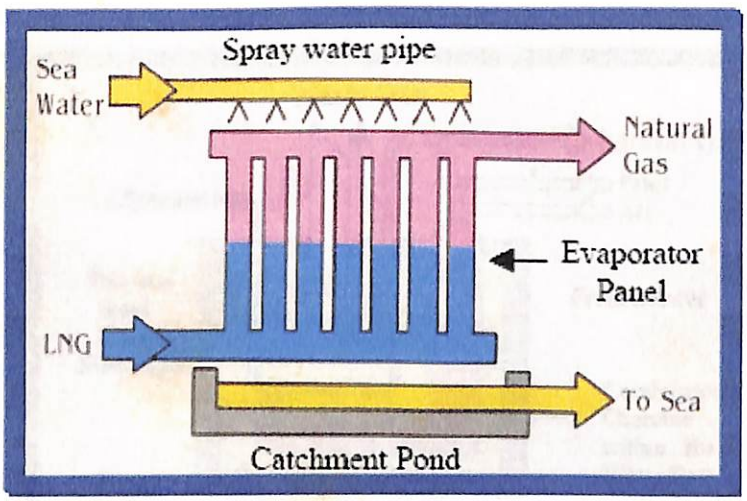
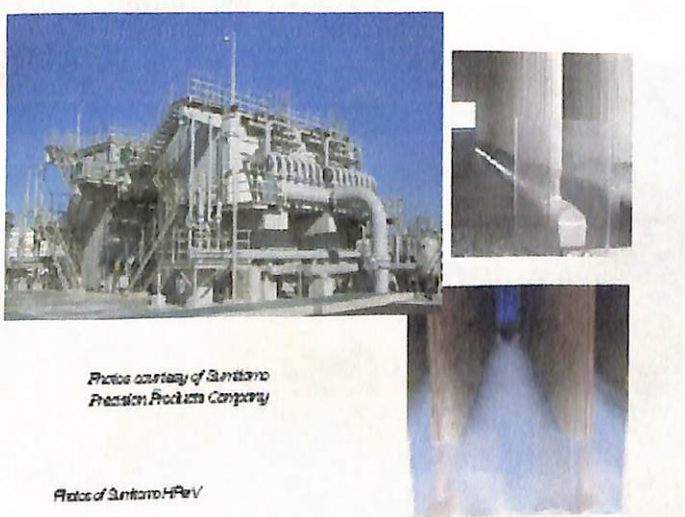


Figure 31 - Open Rack Vaporizer



Submerged Combustion Vaporizers (SCV)

- Higher capital cost
- Smaller in size, require less spaced
- High thermal efficiency, over 95%
- Wide variability for send-out rate
- Required gas to be consumed to heat water bath
- Air emissions (NOx is produced, 30-80 parts per million)
- Bath water will require treatment before disposal
- Heat of vaporization produces excess water which requires treatment and disposal

These are shown diagrammatically in Figure 32 and an actual unit in Figure 33.

Figure 32 - Submerged Combustion Vaporizer (SCV) Diagram

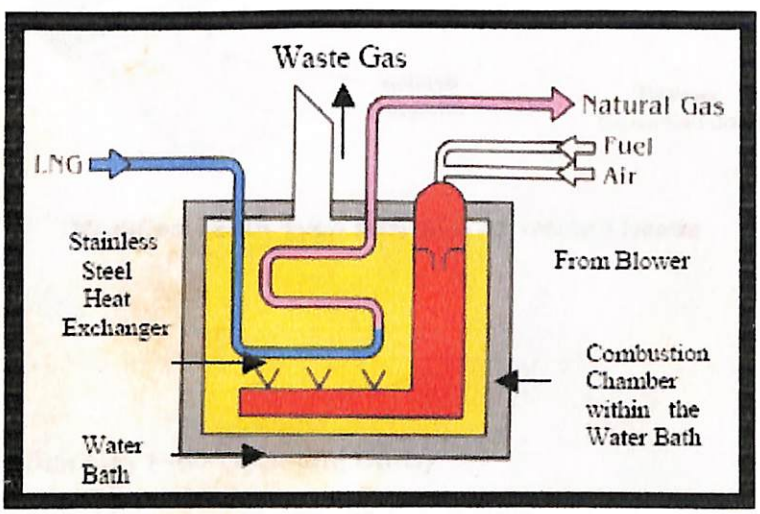
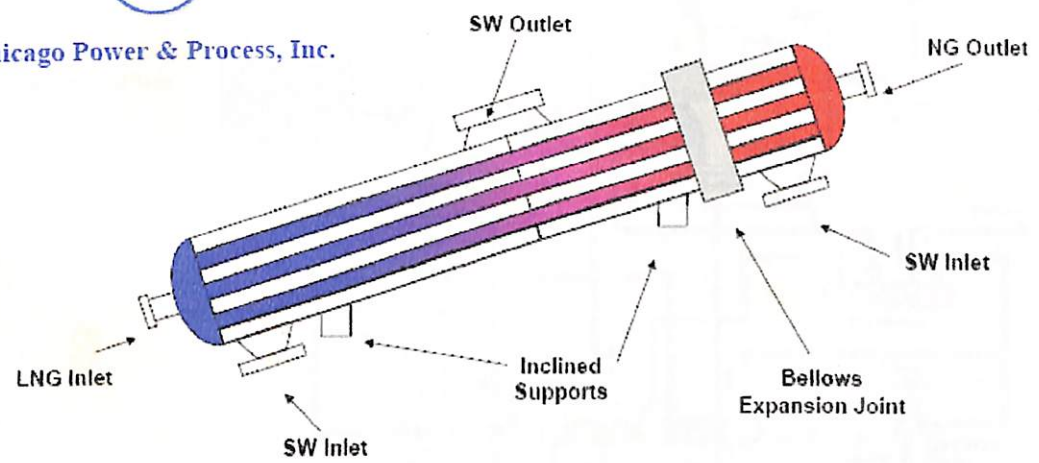


Figure 33 – Submerged Combustion Vaporizer



Shell & Tube Vaporizers (CPP Design)

Chicago Power & Process, Inc.



Modified TEMA Type NJN with all welded heads

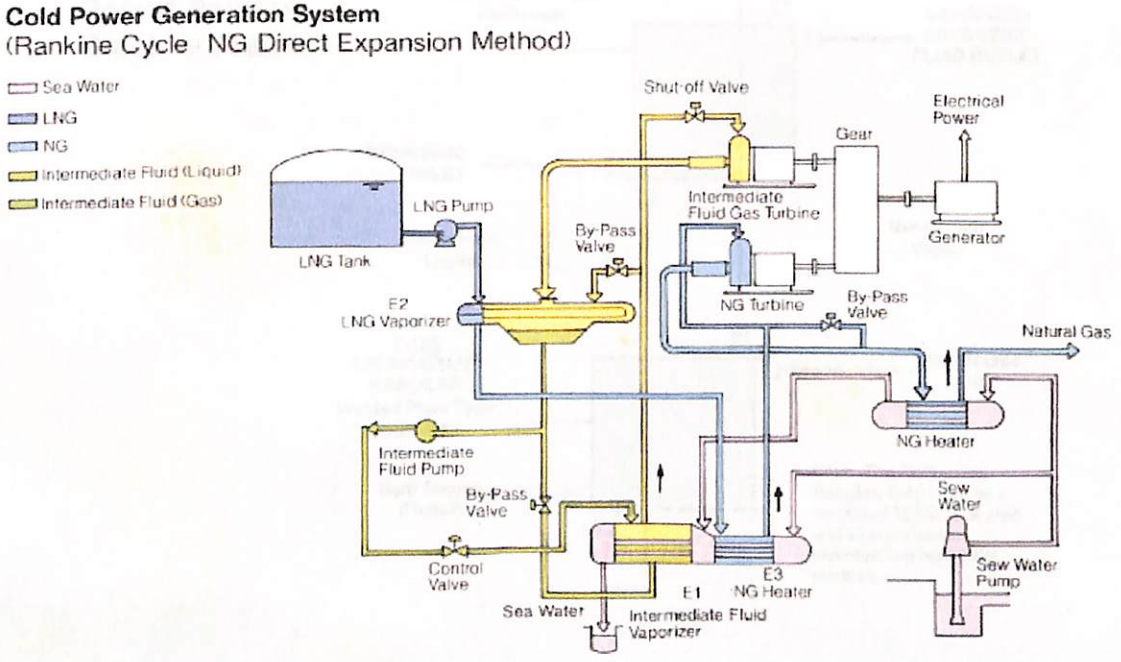
Advantages

- Proven Technology (~60 Operating Units)
- Safe / Minimal Moving Parts / No Ignition Source
- Inexpensive Source of Heat (Seawater)

Disadvantages

- Environmental Impacts on Marine Life
  (Biocide Added / Low Temperature Effluent)
- Large Electrical Power Load
- Periodic Maintenance (Cleaning Intake Systems)
- Safety Concern Due to Relief Valve Issue (Tube Rupture)
- USCG has Suspended Permit Applications for Seawater

Intermediate Fluid Vaporizers (IFV)



Advantages

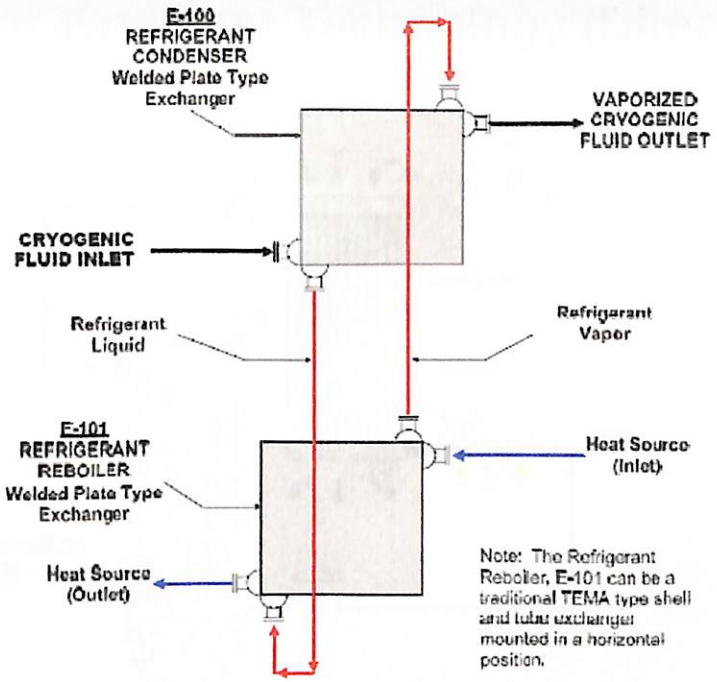
- Proven Technology
- Inexpensive Source of Heat (Seawater or Cooling Water)
- Low Emissions / Low Maintenance
- No Potential to Freeze Intermediate Fluid Refrigerant

Disadvantages

- Environmental Impacts on Marine Life
  (Biocide Added / Low Temperature Effluent)
- High CAPX
- Large Footprint / Weight Restrictions Offshore
- Large Electrical Power Load
- Periodic Maintenance (Cleaning Intake Systems)
- Introduction of Propane to System (Ignitable)

Intermediate Thermosyphon Vaporizers

Patent Pending
Black & Veatch



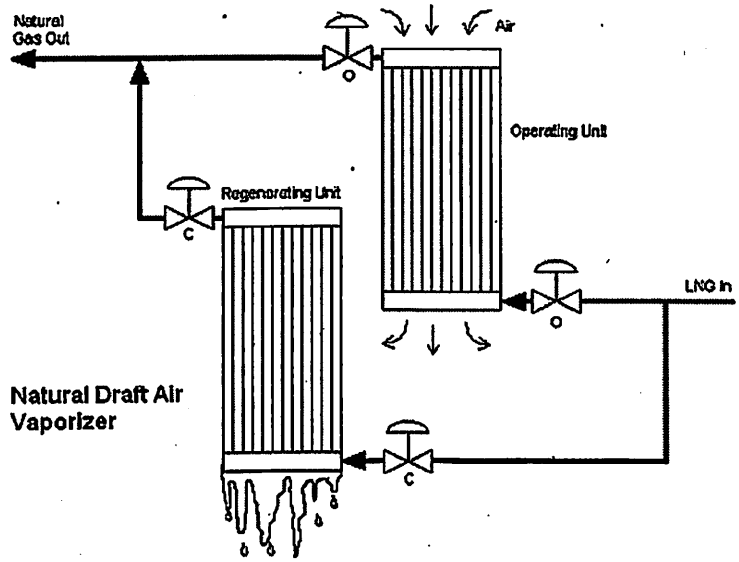
Advantages

- Elimination of Freeze Risk
- No Mechanical or Moving Parts
- Non-Vendor Specific (Competitive Pricing)
- Easy Access to Heat Source Channels
- Small Footprint (Modularization)

Disadvantages

- Introduction of Intermediate Working Fluid (Typically Propane)
- Capital Costs (Up to 2X S&T)
- Still Need an External Heat Source
  (Seawater, Process Cooling Water)

Ambient Air Vaporizer Technology (Direct)



Advantages

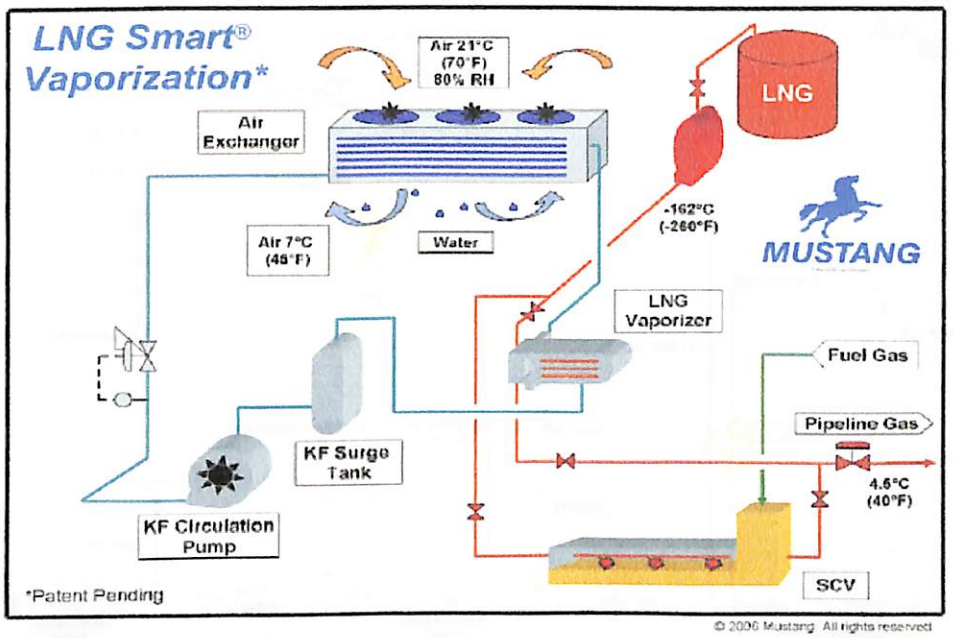
- Inexpensive Source of Heat
- Low Yearly Operating Costs
- Low Emissions / Low Maintenance

Disadvantages

- Dependant on Ambient Conditions (Δ 30°F Approach)
- Unproven Scale Up to Large Commercial Units
- Typically, Large Amount of Real Estate Required
- Cyclic Process (Vaporization and Regeneration)
- Potential to Form a Fog Bank (Natural Draft)

Mustang's LNG SMART Vaporizer

(Indirect Air Vaporization)



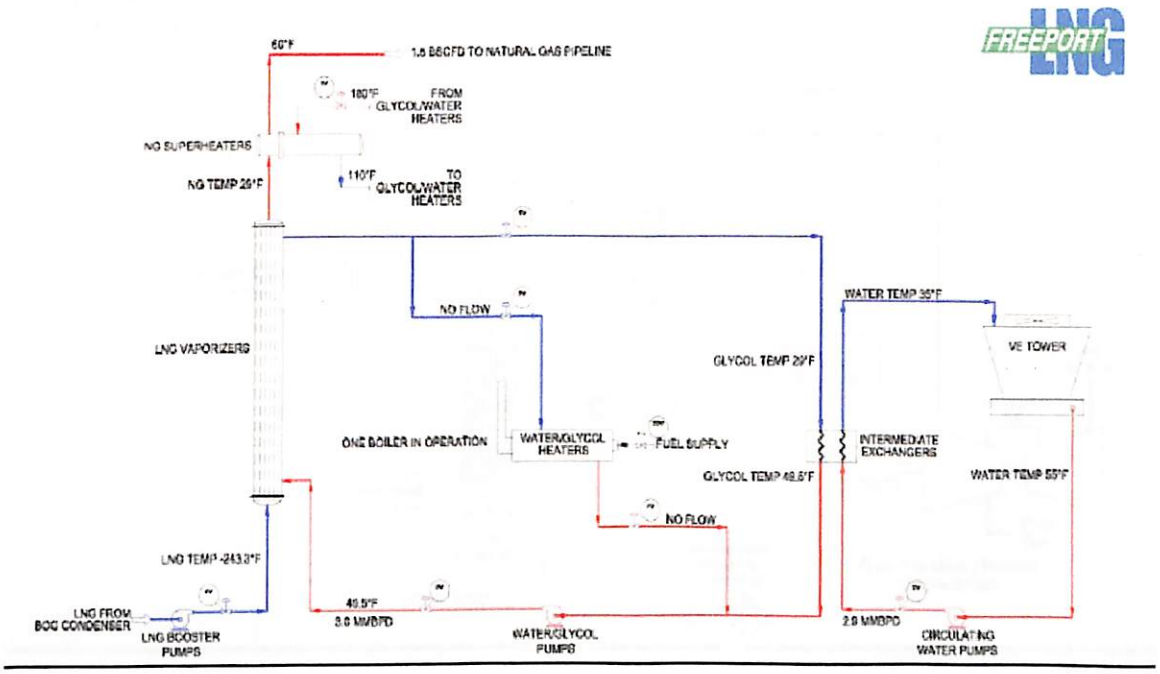
Advantages

- Inexpensive Source of Heat (air)
- Conventional Equipment and Exchanger Technology
- Low Emissions
- Low Maintenance

Disadvantages

- Large Footprint
- Heavily Dependent on Ambient Conditions (Backup Heat)
- Introduction of Intermediate Fluid (Propane, Envirocool, or KF)
- Commercially Unproven (Similar to Dahej, India)

Reverse Cooling Tower



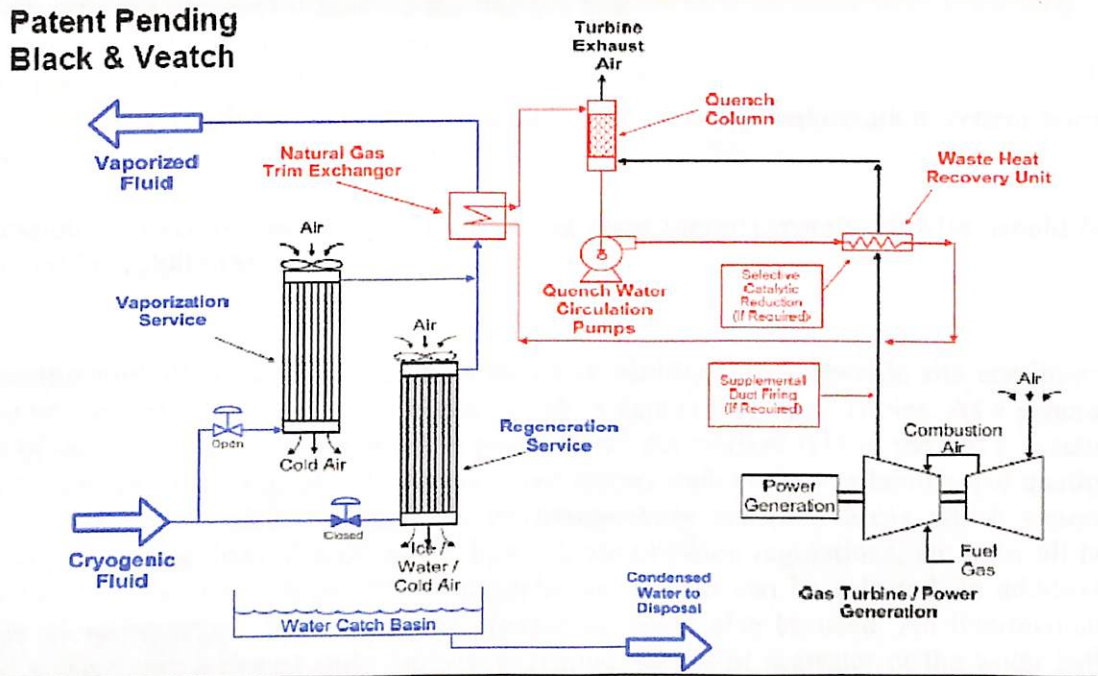
Advantages

- Inexpensive Source of Heat
- Low Yearly Operating Costs
- Low Emissions / Low Maintenance

Disadvantages

- Large Footprint / Weight Restrictions Offshore
- Large Fan Electrical Load
- Commercially Unproven (Under Construction @ Freeport LNG)
- Environmental Concerns with Intermediate Fluid (Glycol)
- Heavily Dependent on Ambient Conditions (Back-Up Heat)

Heat Integrated Ambient Air Vaporizer



Advantages

- High Waste Heat Thermal Efficiency (98%+)
- Less Dependent on Ambient Conditions (>50°F NG Outlet)
- Can Incorporate Emissions Controls (If Required)
- Low Emissions / Low Maintenance
- Footprint and Energy Comparable ORV

Disadvantages

- Large Fan Electrical Load (Similar to ORV pump load)
- Commercially Unproven (Albeit Proven Independently)

COMBINED HEAT AND POWER (CHP)

- Very efficient process by utilizing the flue gas heat
- Requires less capital than ORV, but more than SCV
- More air emissions than ORV, less than SCV systems
- For complete reliability may have to install 100% backup vaporization system when power plant is offline (ORV or SCV)

- Possible to have revenue source from power plant (approximately 80 MW would be required for 1,000 MMSCFD facility)

A combination of the above systems is also a possibility. The specific site conditions must be carefully evaluated to determine which system is the "best" choice. As a general rule-of-thumb, if the sales gas price is above US$3 per million BTUs, the ORV system will be the most cost-effective. However, other factors such as the availability and quality of sea water, sea water temperature, environmentally sensitive areas which cannot tolerate large quantities of cold water disposal, air emission regulations, etc must all be carefully evaluated before the "best" vaporization system can be selected. In addition, either an intermediate fluid system or air-cooling could also be used. An intermediate fluid system uses a heated fluid for heat exchange instead of seawater or the water bath used by the ORV and SCV systems respectively. These systems are primarily applicable for offshore floating systems due to the movement of the vessel and resultant incomplete heat transfer from traditional ORV and SCV systems. However, they could also be used onshore in very specific circumstances.

GAS CONDITIONING

The last part of the facility is the gas conditioning system. In some areas of the world, such as the North American market, virtually all of the LNG produced from the existing liquefaction plants will not meet the send-out gas specifications for heating value and C2/C3 components without additional treating. There are many ways to achieve this, such as:

- Fractionation columns
- Adding inert gases such as nitrogen, turbine exhaust gases, etc.
- Adding compressed air

Depending upon the gas send-out specifications and the quantity of gas being processed, these options may or may not be technically and/or commercially feasible. A simpler method, which is a proprietary Foster Wheeler design, is the use of the LNG as a cooling medium for the fractionation column overhead to achieve an economic separation to reduce the C2 and C3 components. This design requires no gas compression as LNG is used as a refrigerant in a direct-contact condenser. This eliminates the use of costly equipment such as compression and inert gas generation facilities. An added benefit is that a separate revenue stream can be realized from the sale of these liquids to other

industries such as petrochemical plants. However, if no such facilities are close to the receiving terminal, the transportation of these liquids may be very costly. In addition, there will be safety issues related to the storage of C3 material. The remaining design area is that of infrastructure required for the LNG terminal. This involves such items as utilities and housing. In general, the new LNG terminals being considered have tended to be located in remote areas. Thus, power generation, water treatment, and other utilities will have to be provided at the facility to make it self-sufficient and to achieve the desired reliability. The power required for such a facility is approximately 15 MW maximum, so conventional small gas turbines with dual fuel capability are a simple and cost effective solution. However, if locally produced power is available and reliable,

CONCLUSION

Many factors will influence the design and cost of an LNG receiving terminal. Some will relate to the Owner's preferences and some will be mandated by the regulatory authorities and applicable design codes. Early and comprehensive communication between all parties ,as well as early trade-off studies will ensure that the facility meets all of the owner's objectives – cost, reliability, schedule ,safety and security – as long as this is accomplished early in the design engineering cycle.

In order for LNG to become the energy source of choice, the cost of the LNG chain has to be competitive with alternate fuel sources. The trend in the future is towards large liquefaction train sizes and fit-for-purpose plants to reduce the capital cost of the liquefaction facilities. LNG train size up to 7.5 to 8MMTPA is currently being considered. However, several commercial and technical challenges will have to be overcome to make this a reality.

The commercial challenge is related to securing a market for large quantities of LNG to support financing of the project. The technical risks are associated with limitations on equipment sizes specifically for the refrigeration compressors and its drivers.

On the terminal side, there is a high level of interest in moving facilities offshore due to environmental and permitting issues. Several companies have proposed concepts for offshore storage and regasification terminals. Other areas of interest are integration of receiving terminals with facilities such as power plants or air separation units.

The LNG technology has grown to be a major factor in the world energy market. It has established itself as a proven method for monetizing stranded gas. With the anticipated growth in gas demand, declining reservoirs in the US and Europe and strong growth in many other markets, LNG is expected to play a bigger role in stranded gas.

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