LNG IMPORT TERMINALS
– RECENT DEVELOPMENTS

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Abstract

There has been a recent renewal of interest in LNG import terminals, as the worldwide gas market continues to grow to supply domestic/industrial users and in many cases new power generation projects. LNG imports are planned in North America and in Spain and Italy as well as other locations. This paper reviews LNG import terminal designs as well as the major factors impacting the terminal cost. It looks at the integration of LNG import terminals with electric power generation plants being considered for new projects and the potential benefits. Some new developments are overviewed to show how some projects can be implemented in spite of initial local opposition. The overall goal being a fit-for-purpose, low cost LNG import terminal which maximises revenue from gas and power sales.

I. Introduction

The worldwide liquefied natural gas (LNG) trade has increased steadily (over 5 % per year) since the industry began. It stands at 120 MTPA in 2002 and is expected to rise to 160 MTPA in 2005/6. This trend is expected to continue as natural gas becomes the fuel of choice for electric power providers and as developing countries increase their energy demands.

The receiving terminal is one component of the LNG chain between the gas field and the residential or industrial consumer. This paper reviews the LNG receiving terminal process and equipment currently in common use in a number of Kellogg designed facilities as well as describing some newer features being considered.

Integration with power plants is currently under consideration for a number of projects and some of the issues will be described in this paper

II. The Process

A simplified process flow diagram is shown in Figure 1.

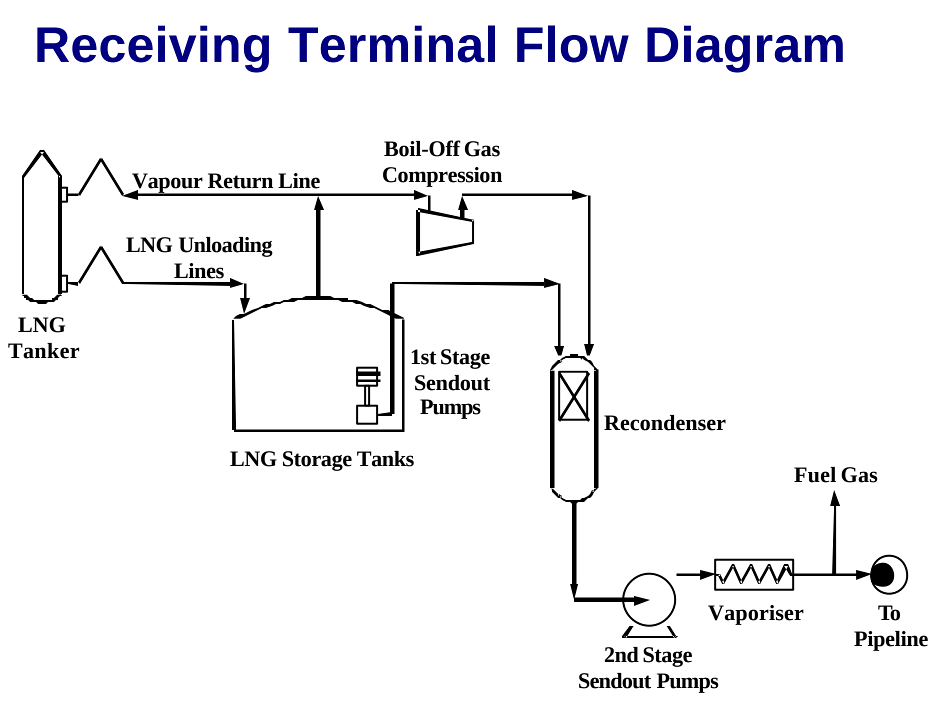


Figure 1 – LNG Receiving Terminal Simplified Process Flow Diagram

The LNG receiving terminal receives liquefied natural gas from special ships, stores the liquid in special storage tanks, vaporises 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 terminal consists of:

- LNG unloading system, including jetty and berth
- LNG storage tanks
- LNG vaporisers
- In-tank and external LNG pumps
- Vapour handling system
- Supporting utilities, piping, valves, control systems, and safety systems required for the terminals' safe operation.
- Infrastructure (roads, fencing and buildings)

Receiving terminals to date are expected to operate close to 365 days per year and have spared equipment to achieve this availability. The one exception is that a shutdown may be necessary for a statutory inspection of vessels or maintenance of some critical items such as the flare. Spare equipment can be eliminated and cost savings achieved if line packing can be used or if some of the gas consumers can tolerate interruptions in the send-out supply.

The process is further described below.

1. LNG Ship Unloading

Following ship berthing and cool-down of the unloading arms, 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 87,000 m^3 to 145,000 m^3. The liquid unloading rate from the ship is usually 10-12,000 m^3/hr carried out by eight pumps with two pumps located in each of four cargo tanks onboard a typical ship. It takes approximately 12-14 hours to unload one 135,000m^3 ship. From the ship the LNG flows through the unloading arms and the unloading lines into the storage tanks. The loading lines can be two parallel pipes or a single larger pipe.

During ship unloading some of the vapour generated in the storage tank is returned to the ship’s cargo tanks via the vapour return line and arm, in order to maintain a positive pressure in the ship. Due to the low pressure difference between the storage tank and the ship, vapour return blowers are sometimes needed. However, for full containment storage tanks where the design pressure is approximately 290 mbarg, enough pressure is often available to return vapour without using vapour return blowers.

It is customary to have three unloading arms for LNG and one arm for return vapour, but there is cost-saving potential in reducing the number of LNG arms to two if hydraulics permit and the ultimate unloading duration has some flexibility. Phased installation of arms could also be considered. Eliminating the vapour return to the ship is another cost savings measure that is worth exploring but has yet to be incorporated. New LNG ships could be designed to generate enough vapour to make up for liquid displacement, and strictly speaking would not need a vapour return line. LNG ships already include vaporisers to enable the cargo to be used as fuel when gas is less costly than Bunker C and this system could be extended to provide displacement gas. It would however be necessary to stipulate the use of customised ships that could be at a premium. The drawback of eliminating the vapour return line is that in the event the ship boiloff vapours build up to the point of venting before unloading begins, the vapours will exit via the ship vent and become a safety issue. With a vapour return line any excess ship boiloff is vented to the receiving terminal vapour handling system.

2. LNG Storage

Two or more above ground tanks are generally installed for receiving and storing LNG, though terminals have been designed by Kellogg and built with a single tank. To reduce cost, designers try to minimise the number of tanks and maximise the amount of storage per tank. If the facility has only one tank then sendout and LNG unloading will be from the same tank. This does not cause any operating difficulties when properly designed and operated.

The main tank types are

1. Single containment
2. Double containment
3. Full containment
4. Membrane

The single containment tank has an inner wall of 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. The carbon steel outer tank is not capable of containing cryogenic materials; thus the only containment is that provided by the inner tank. However, single containment tanks are surrounded by a dike or containment basin external to the tank, either of which provide secondary containment in the event of failure.

The double containment tank is similar to a single containment tank, but instead of a dike there is an outer wall made of pre-stressed concrete. Thus if the inner tank fails the outer wall is capable of containing cryogenic liquid. The outer concrete wall adds to the tank cost but less land is required because the diked area is eliminated. Should the inner tank fail, then whilst the liquid will be contained, vapour will escape through the annular gap.

A full containment tank is one where the annular gap between the outer and inner tanks is sealed. Generally this type of tank has a concrete roof as well as a pre-stressed concrete outer wall. The outer wall and roof now can contain both cryogenic liquid and vapour generated. The weight of the concrete roof permits a higher design pressure [290 mbarg] than a metal roof tank [170 mbarg].

Double metallic tanks have also been constructed in Japan that can be considered as full containment. The outer tank is made of materials that can withstand LNG and retain both liquid and vapour.

The size of LNG tanks has been increasing over the years. In general the largest common tank size is 160,000 m^3. Toyo Kanetsu K.K. has however now constructed a single 180,000m3 tank for Osaka Gas in Japan [1].

The membrane type storage tank is a pre-stressed concrete tank with a layer of internal insulation covered by a thin stainless steel membrane. In this case the concrete tank supports the hydrostatic load which is transferred through the membrane and insulation (in other words, the membrane is not self-supporting). The membrane must shrink and expand with changing temperatures. Existing in-ground membrane tanks have capacities up to 200,000 m^3.

The decision to use single, double, or full containment is based on capital and operating cost, land availability, separation distances to jetty and sometimes protection from external events such as vapour cloud blast pressure, missiles or small aircraft.

Full containment tanks are more expensive than single containment tanks. Before a particular type is finally selected it is important to consider the higher capital and operating cost of vapour handling equipment as well as the higher cost of safety features such the firewater system associated with single compared to full containment tanks. Where site conditions make land availability restrictive or where special protection from external events is required then a full economic analysis should be carried out that will generally favour concrete roof tanks

Current industry practice is to have all connections to the tank (e.g., filling, emptying, venting, etc.) through the roof so that if a failure of a line should occur it will not result in emptying the tank. Each tank has the capability to introduce LNG into the top or the bottom section of the storage tank. This allows mixing LNG of different densities and prevents the phenomenon known as “rollover” which can result in rapid vapour generation. Filling into the bottom section is accomplished using an internal standpipe with slots, and top filling is carried out using separate piping to a splash plate in the top of the tank. It should be noted that some tanks have been installed with a side wall penetration in Japan but this could not be consider as popular in outside of Japan.

3. Vapour Handling

During normal operation, boil-off vapour is produced in the tanks and liquid-filled lines by heat transfer from the surroundings. This vapour is collected in the boil-off header that ties into the boil-off compressor suction drum. An in-line de-superheater, located upstream of the drum will inject LNG into the gas stream if the temperature rises above minus 80°C (LNG temperature is approximately minus 162°C). Boil-off vapours generated during normal operation (not unloading) by heat leak into the storage tank and piping are compressed and liquefied in a recondenser.

During ship unloading, the quantity of vapour in the tank outlet increases significantly. These additional vapours are a combination of volume displaced in the tanks by the incoming LNG, vapour resulting from the release of energy input by the ships pumps, flash vapour due to the pressure difference between the ship and the storage tanks and vaporisation from heat leak through the unloading arms and transfer lines.

Boiloff gas compressor vendors are addressing the need to allow operation with warm inlet gas and thus avoid the need for LNG injection and hence the requirement for a compressor suction drum.

From the compressor suction drum, vapour can be routed to the boil-off gas blowers for vapour return to the ship or to the boil-off gas compressors. The vapour that is not returned to the ship is compressed and directed to the recondenser. The amount of vapour that can be recondensed depends on the amount of LNG send-out. If there is not enough LNG send-out to absorb the boiloff vapour then the vapour must be compressed to pipeline pressure, or flared or vented. Thus the priority for handling vapour is in the following order of preference:

- Make up displacement in ship and storage tanks
- Recondense into send-out LNG
- Compress to pipeline pressure and send to pipeline
- Flare or vent to atmosphere

Installation of a pipeline compressor can usually be avoided by analysing the sendout rates in terms of the frequency of low sendout rates and the value of the gas saved compared to the installed cost of the equipment.

4. First Stage LNG Send-Out Pumps

Several low-head LNG send-out pumps are normally installed in each LNG storage tank. These pumps operate fully submerged in LNG and are located within pump wells or columns, which allow easy removal and installation. 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.

The first stage pumps usually have a discharge pressure of approximately 11 bar, and since the saturation pressure is approximately 1 bar the LNG is effectively sub-cooled by 10 bars. This sub-cooling provides the thermal capacity needed for recondensing boil-off vapour in the next processing step.

Minimising cost leads to the tendency to select fewer larger pumps. LNG pump vendors experience needs to be reviewed carefully to ensure that adequate operational experience exists at the selected flow/head combination. If adequate references are not available then the success of the project may be at risk due to an unproven pump and will require additional attention during the design, construction and testing phases.

5. Recondenser

LNG from the in-tank pumps is routed directly to the recondenser vessel. The boil-off vapours generated during normal operations are routed to this vessel and mixed with the subcooled

LNG to be condensed. This will avoid flaring or venting for most operating conditions. The recondenser houses a packed bed that creates a large surface area for vapour-liquid contact.

6. Second Stage LNG Send-Out Pumps

The send-out gas is usually injected into a high pressure gas distribution system of approximately 80 barg. To achieve this pressure multi-staged high head send-out pumps are required. The pumps take LNG from the recondenser and supply it to the vaporisers at a pressure suitable for the pipeline.

As described for the intank pumps, pump vendor experience also needs to be reviewed for the sendout pumps.

7. LNG Vaporisers

LNG terminal facilities have multiple parallel operating vaporisers with spares. Open Rack Vaporisers (ORV) are common worldwide and use seawater to heat and vaporise the LNG. Submerged Combustion Vaporisers (SCV) use send-out gas as fuel for the combustion that provides vaporising heat. Due to the high cost of the seawater system ORV installations tend to have a higher installed capital cost while the SCV installations have a higher operating cost because of the fuel charge. At many facilities an economic design can be achieved by using ORVs for the normal range of sendout and SCVs as spares.

Other site factors also impact the decision of whether to use ORVs or SCVs. If the seawater temperature is below approximately 5°C, ORVs are usually not practical because of seawater freezing. At some sites it is not practical to separate the seawater discharge from the seawater inlet, and SCVs must be installed to avoid recirculation problems. Use of submerged combustion vaporisers leads to environmental concerns because of carbon dioxide and NOX emissions. The excess water produced as a result of the fuel combustion requires treating before discharge.

In addition to ORVs and SCVs, shell and tube vaporisers are now being considered for specific applications, particularly where an alternate source of heat is available such as from a power plant or 'cold energy' utilisation process.

a) Open Rack Vaporisers

Seawater in an open rack, falling film type arrangement vaporises LNG passing through the tubes (see Figure 2 overleaf). The water falls over aluminium 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 for the vertical seawater and firewater pumps in the basin. The pumps are located in individual separate bays within the intake basin. At the inlet of each seawater pump bay, a travelling band screen may be provided for further removal of suspended solids to prevent blockage or damage to the open rack vaporisers.

Electrochlorination units provide chlorine to be dosed into the seawater at the inlet to the intake basin to control marine growth in the system. Provisions are also made for shock dosing of the individual pump bays.

Single ORV units have been installed for a gas send-out rate of 180 t/h.

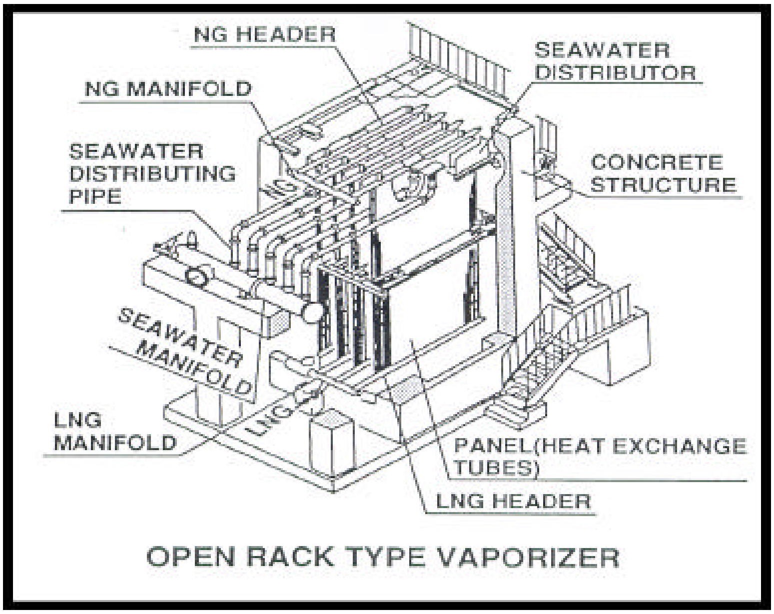


Figure 2 - Open Rack Vaporiser

b) Submerged Combustion Vaporisers

These vaporisers 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 (see Figure 3).

The largest single SCV units installed are for a gas send-out rate of approximately 120 t/h.

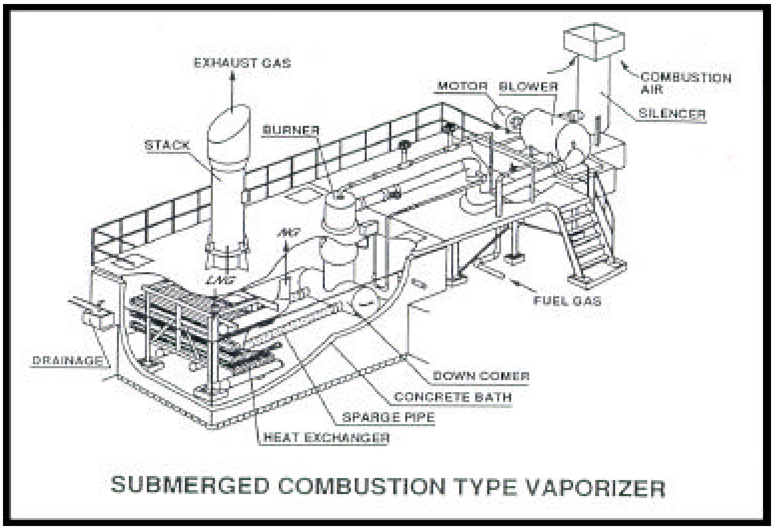


Figure 3 - Submerged Combustion Vaporiser.

As previously mentioned, the SCVs have a high operating cost, however they are smaller than ORVs and have a high thermal efficiency (>95%).

c) Shell and Tube Vaporisers

These vaporisers are specially designed shell and tube heat exchangers, which utilise a variety of heating mediums as energy sources.

Amongst the first shell and tube units were those installed by Kellogg at the Cove Point terminal in the US where heat extracted from gas turbine exhausts via a glycol/water loop was used to vaporise LNG (see figure 4).

Figure 4 – Cove Point Vaporisers

Shell and tube units have also been developed by Kobe and are currently in use at two LNG terminals in Japan. In both cases an intermediate fluid is used which is vaporised by the heating medium and condensed by the LNG. The heating medium can be seawater, fresh water or a glycol/water mixture.

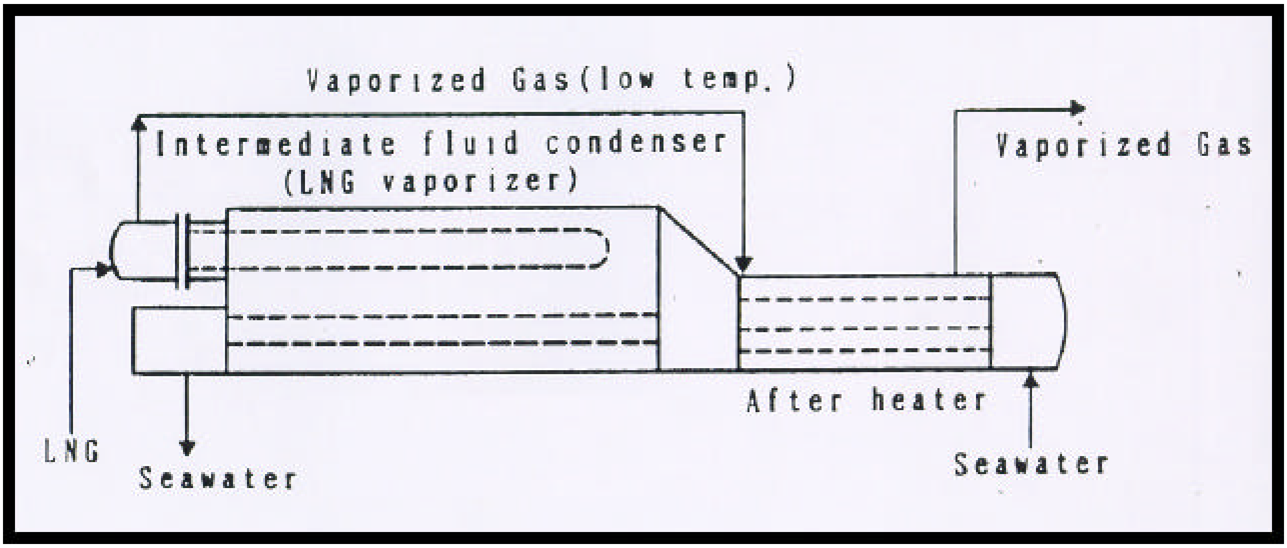


Figure 5 – Schematic of Shell and Tube Vaporiser with Intermediate Fluid.

The US natural gas distribution system includes a large number of “peak shaver” units, which liquefy gas in times of surplus and then sendout when demand is high. A large number of these units have built since the late 1960s. Many of these units use shell and tube vaporisers which do not include an intermediate fluid between the vaporising LNG and the heating medium. A fired heater was used to heat a circulating glycol/water loop that vaporised the LNG directly in a specially designed shell and tube exchanger unit. This exchanger includes some patented features to overcome any problems associated with freezing of the heating medium and to ensure good distribution of LNG across the bottom tube sheet. The glycol can also be heated by the inlet air to a CCGTG plant as shown in Fig 6 below.

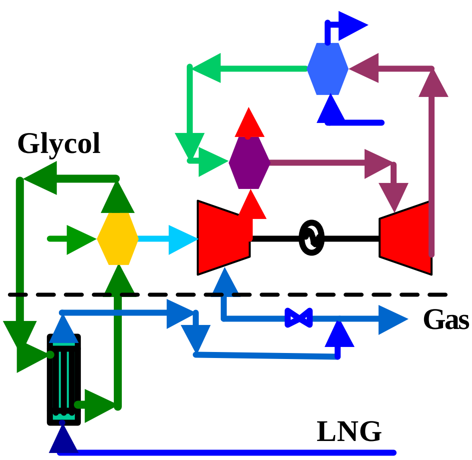


Figure 6 – Shell and Tube Vaporiser, Design as supplied by Chicago Power and Process Inc. The shell and tube units are shown used in an integrated LNG terminal/power plant scheme. The units can also be used directly with seawater as demonstrated in at least two recent applications.

8. Vent System or Flare

During upset, extreme turndown or emergency conditions, vapours may be generated within the terminal that exceed the capacity of the recondenser and pipeline compressor (if it is included). If this occurs the vapour is vented to the atmosphere through an elevated vent stack or a flare for safe disposal.

The preferred method of disposal is generally to flare the gas. Venting is feasible but it requires special consideration. Although it may be preferred because it is less visible to local residents the vent still has to be designed for accidental ignition by lightning so does not reduce the sterile area requirement and deletion of the ignition system is not a significant cost advantage.

Dispersion of cold gases from a vent is more problematic than flaring - flared gases will always rise. Cold methane could slump after discharge from a vent and linger at grade above the LFL. Heating could be considered but quick response could be difficult. The global warming potential of methane is ~21 times that of CO_2 - so each methane molecule would be 21 times better burnt than just vented.

The tank vapour system is manifolded and a pressure control valve sends vapour to the vent or flare stack before the storage tank safety valves open. The storage tanks themselves are equipped with relief valves as the last line of defence against overpressure. Vacuum breakers are also provided to protect against external overpressure.

9. Utilities

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 units
- Electric power
- Firewater
- Foam system
- Plant water/fresh water/ tempered water
- Plant and instrument air
- Nitrogen (storage and vaporiser)
- 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, Guardhouse

10. LNG Shipping

Protection of the LNG tanker during navigation, berthing/unberthing and while docked and unloading is a major design consideration. Also, the transfer of LNG is a relatively high risk part of the 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, and anti-pressure surge protection of piping.

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

- 80,000 to 145,000 m^3 capacity, having a maximum overall length of up to 310m, width of 46 m, and fully loaded draft of 11.6 m. The net delivery unloading rate into the receiving terminal is approximately 12,000 m^3/hr. There are smaller ships (down to less than 60,000 m^3) 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.

III. Site Variables

The cost of an LNG receiving terminal is highly dependent on the selected site, but a typical cost distribution is provided in the table below:

Area	Percentage
Jetty	11
Tanks	45
Process	24
Utilities	16
General Facilities	4
Total	100

Factors that change the above breakdown are many and include the following:

- Marine Conditions: The cost of the jetty naturally depends on the jetty length, and if the sea bed depth increases gradually, the jetty length increases, in some cases dramatically. Dredging may also be an option in which case the capital cost (Jetty plus dredging) may be lower but the operating cost (maintenance dredging) increases. The cost of the jetty also depends on submarine soil conditions if substantial piles are required. Another major item that may be needed is a breakwater if the site has an unprotected shoreline. The breakwater reduces shipping delays, and pays out if the site frequently has high waves. But it can significantly increase both cost and schedule.

- 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. These include:

  Pre-loading to accelerate settling
  Stone columns (sand drains)
  Piling

  But all of these increase the project cost.

- Soil improvement by any method is expensive, and a rough estimate of piling costs provides an idea of the potential impact. Considering that the project can require around 2,000 piles (not including those for the storage tanks which may number another 1,000) at $5,000-$10,000 each, it is seen that poor soil conditions can impact the project cost by more than $10-20 MM.

- Storage type: Single containment storage is the least expensive type of storage, but as outlined earlier single containment storage takes more land and may not be practical at some sites. Full containment tanks cost approximately 25-50% more than single containment tanks.

- LNG tank specified for a full height hydrotest will have over twice the hydrostatic pressure and weight during the test compared to actual operation. The shell thickness and tank foundation must be designed for the full hydrotest load and this adds to the cost. LNG storage tanks on past projects have been hydrotested to the full inner tank height, but current industry practice is now partial hydrotest.

- Power generation on site: One of the more costly utilities in a receiving terminal is power generation, however many facilities import power from the local grid to reduce capital cost expenditure. Regardless of the source of power, LNG terminals have small emergency generators to enable orderly shutdown in the event of a power supply failure.

- Labour: Construction labour is a major cost factor that varies widely from site to site. Unlike liquefaction terminals, receiving terminals are often located near population centres. If this is true then it may be possible to obtain much of the required skilled labour locally. Using local labour 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 the option of a camp.

IV. Current LNG Receiving Terminal Activity

A large number of terminals are being planned in the US and in Mexico to provide gas into the Southern United States to address supply shortages. Existing terminals at Everett in Massachusetts and at Lake Charles in Louisiana have been or are currently undergoing expansion. Two mothballed terminals in the US, Cove Point in Maryland and Elba Island in Georgia, are also coming into service in 2002/3.

Many terminals have been proposed in India to supply industrial users such as fertiliser plants and both new/converted power plants. However the difficulties experienced by Enron at Dahbol mean that projects are now more difficult to initiate.

Spain continues to exhibit a large appetite for LNG to supply new power generation projects and for expansion of its domestic as well as commercial sectors. All three of the existing terminals are being expanded and three new terminals are being developed.

Both Spain and Greece have a tourist industry spread out over many islands with increasing power needs. Where power is currently generated from liquid fuels there will be pressure to convert to gas for environmental and unit cost reasons, which will mean additional terminals where pipe gas is not economic.

The terminal being built in Portugal for Transgas Atlantico is expected to be operational in the 3rd quarter of 2003.

Italy currently only has one terminal at Panigaglia. This terminal has under gone extensive renovation to bring it up to current standards of safety. Additional terminals have been considered at two locations but both have found difficulties with local opposition to industrial development as well as tanker movements. An offshore LNG terminal design has been prepared but it is still not under construction.

In the UK LNG imports are being considered within the next 2-3 years to maintain supplies as well as provide competition in the market place. Sites in the Thames estuary near London as well as at Milford Haven are being considered. Both locations have the benefit of existing deep-water harbour facilities and being located within existing industrial areas thereby reducing costs and simplifying planning.

China is the latest country to enter the LNG business with its first terminal being designed close to Shenzhen in Guangdong province. A second terminal is planned at Xinhua in Fujian province.

V. LNG Cold Utilisation & Integration with Electric Power Plant

LNG is most commonly vaporised in ORVs against the seawater or in SCVs where the cold energy contained in the stored LNG is essentially wasted during the regasification process. The cold potential can be harnessed in several ways by integrating LNG vaporisation process for improved performance, lower capital and operating costs.

Some of the possible methods of LNG cold utilisation are listed below:

- Air separation
- Electrical power generation
- Seawater desalination
- Chilled water for refrigeration and industry
- Cold storage and frozen foods
- Cryogenic crushing
- CO_2 and dry ice production
- Ethane/Propane extraction

LNG cold utilisation is most economical when gas send-out rates are high and continuous, and although many operators wish to avoid extra equipment and complexities, the concept is in common use in Japan. The development of these opportunities to utilise 'cold energy' happens progressively so as to allow several disparate business to naturally grow.

The LNG cold can also be more effectively utilised by integrating the receiving terminal with an external simple or combined cycle gas turbine power plant, which will result in increased power production. This has been the focus of integration within a number of projects over the last 10 years; some examples are listed below:

- BBG at Bilbao, Spain. Hot sea water supplied to vaporisers
- Enron at Dabhol, India. Cold methanol/water used to chill gas turbine inlet air
- Eco Electrica at Penuelas, Puerto Rico. Cold glycol/water used to chill gas turbine inlet air

The integration of terminal and power plant can take the following forms:

- Sea water system integration by chilling of cold water or by re-use of hot water
- Cold transferred to gas turbine inlet air chilling

The sea water usage of a terminal is significantly lower than that of a conventional combined cycle power plant (CCPP) as shown in the figures below:

- Typical CCPP Output = 380 MW
- Fuel Requirement = 50 t/h
- Sea Water to Steam Surface Condensers = 25,000 m^3/h (10^oC temperature rise)
- Sea Water to LNG Vaporiser = 1,800 m^3/h, 5^0C temperature drop

Using the cold from the vaporisation of the CCPP fuel feed will drop the sea water temperature to the power plant by 0.3^0C. When this is translated into a lower steam condensing temperature an additional 0.2 MW of power can be generated from the steam turbine corresponding to an increase of less than 0.1% for the entire CCPP. Recovery of cold from the total terminal sendout will increase power recovery. However a tenfold increases in sendout rate would only increase the additional power to approximately 0.5% making such integration only marginally attractive.

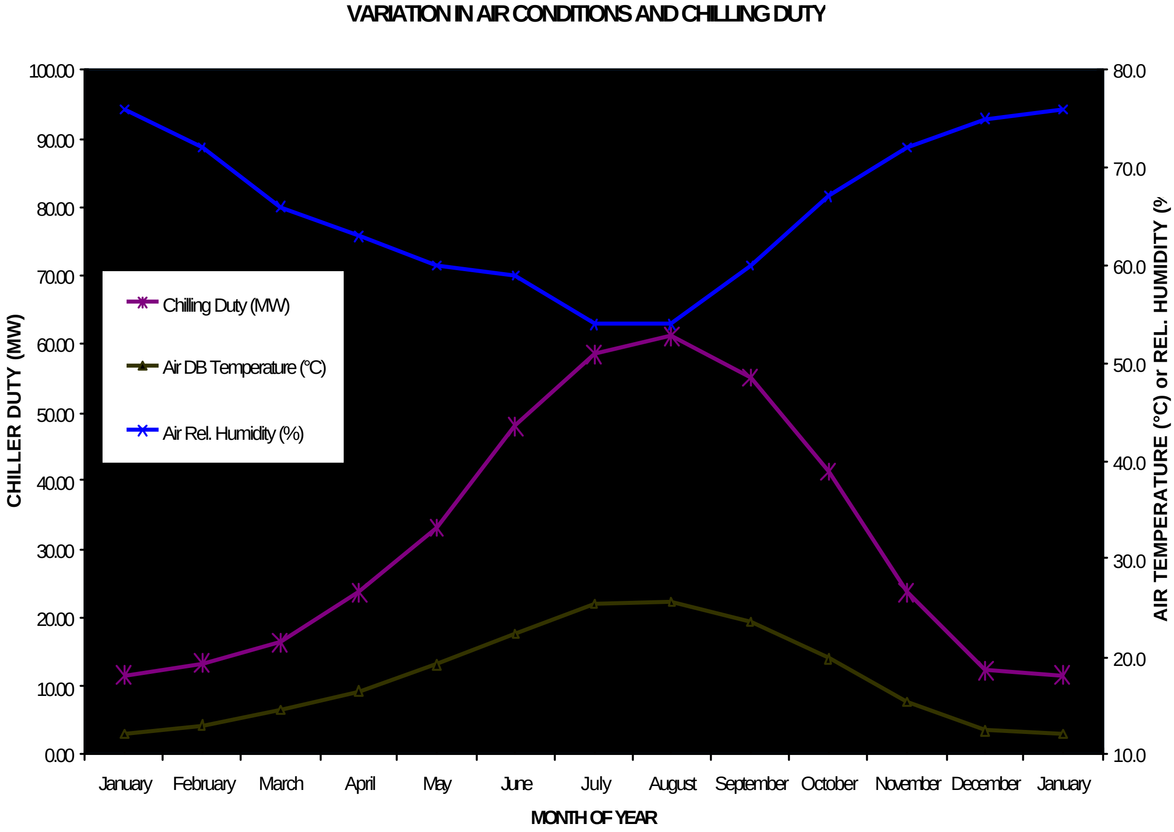
Re-use of hot water from the power plant in the terminal provides only a marginal increase in vaporisation capacity since the improvement in overall temperature difference is limited. It is imperative that vaporisation can continue even if the power plant is completely out of service. It must be possible to run the seawater pumps even if the power plant is down. The water will have to bypass the CCPP condensers to allow maintenance.

Some overall substantial CAPEX savings may be possible if the sea water intakes and outfalls of the power plant and terminal can be combined.

The cold from the vaporising LNG can be transferred to the gas turbine generator inlet air by a suitable heat transfer fluid. Given that a similar volume of air enters the gas turbine irrespective of temperature, at lower temperatures the mass of air increases. Some additional fuel is then fired to maintain combustion conditions and incremental power is generated from the expansion of the higher mass of exhaust gas.

Figure 7 below shows monthly average dry bulb temperature and humidity at a typical site. On the basis that cooling of air is limited to a minimum temperature of 7^{0}C [Explained later], the chilling duty throughout the year is also shown for a typical 380 MW CCPP unit.

Figure 7



In order to prepare a design for this system it is necessary to understand the operating patterns of both the terminal and the power plant as well as understanding the weather patterns. Both the terminal and the power plant can be either base load or peaking facilities.

Implementation of the air chilling system will generate additional electrical power but it will increase the cost of both the terminal and the power plant. The economics of the integration will depend on the value of the increased power export taking into account the extra fuel usage. The potential is clearly greater in areas where the temperature rarely falls below 20^{o}C. The incremental power will certainly be much cheaper to produce than installing dedicated standalone equipment to generate the same power.

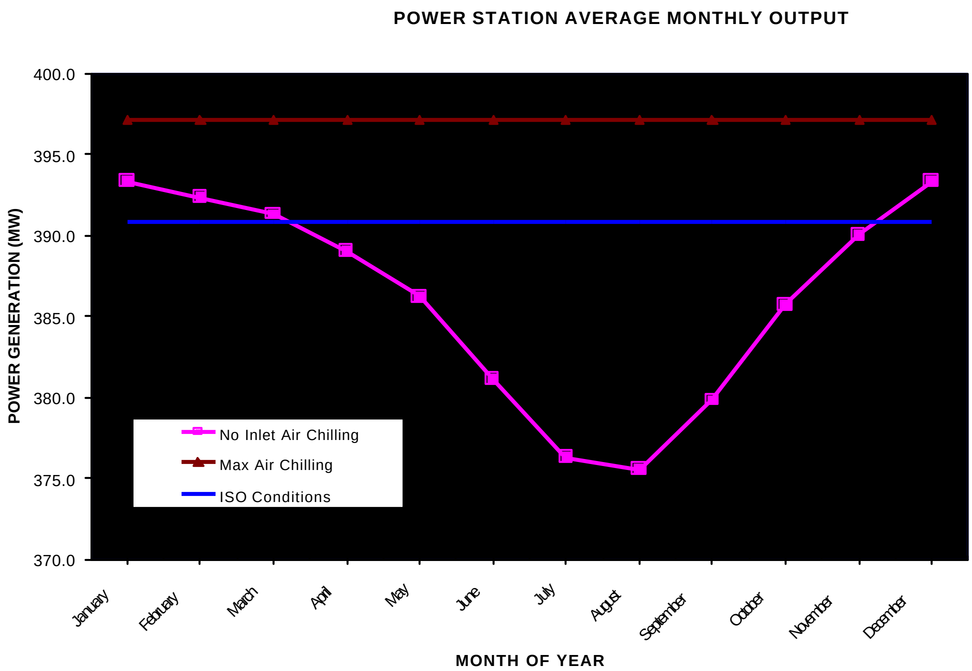
It is important to recognise that although the power plant is capable of generating this additional electric power it must be sold into the network before it has any value. Ideally it should be set-up to run as a base load facility maximising power output at all times.

Estimation of the potential benefits takes into account the following steps:

- Obtain weather data, temperature and humidity data throughout the year both averages for economic analysis as well as extremes to ensure the proposed design can cope while providing acceptable gas sendout or power production capability.
- Develop monthly sendout pattern from terminal design basis.
- Develop maximum cold available from sendout vaporisation
- Obtain air chilling available by applying the available cold to the air intake of the operating gas turbines. It is critical to take account of the humidity of the air since condensation of water requires additional ‘cold energy’.
- Estimate the incremental power that can be produced for the available chilling.

Note that the largest power benefit occurs in the summer when temperatures are higher but humidity may be low. In the summer months the chilling counterbalances the power loss due to higher ambient temperatures. The estimated power benefit will need to take into account the additional pressure drop in the air inlet caused by the air chiller. Figure 8 below shows a typical power station power output with and without inlet air chilling as well as the power output at ISO conditions. The chilling is supplied by approximately 300 t/h of LNG sendout.

Figure X8



Specification of the air chilling system for a particular application involves the selection of the following parameters:

- Heat transfer medium. Glycol/water, methanol/water or seawater can be considered.
- Optimisation of the cooling medium composition can lead to savings in heat exchanger area as well as piping and pumping costs.
- Operating conditions around the loop. Gas turbine vendors are not keen to chill moisture laden air below 7^0C since downstream of the chiller additional pressure drop will further chill the air causing further condensation of water, which might freeze and damage the blades.

- The cooling medium supply temperature should not be colder than 1 or 2^0C since this will avoid freezing of the condensed water
- The gas turbine vendor will want to provide for the chilling coil in his layout and will insist that any condensed water is collected and removed from the air stream prior to the air compressor intake. Approximately 10 t/h of water needs to be removed from a 380m MW CCPP with chilling in a typical warm European country.

Co-operation between the LNG receiving terminal operator and the power plant is essential for any mutually beneficial commercial synergy between the two units. One of the major issues is balancing the loads. The production of both the units is dependent on the performance of each facility. The two units must operate consistently close to their optimum level for a successful integration.

VI. Other Concepts Under Development

Given the reluctance of some local communities to permit the siting of terminals onshore with shipping coming close to land a number of concepts are being developed which will permit LNG import schemes in these places.

There is interest in avoiding ships coming in close to shore by providing for ship unloading at significant distances offshore.

The construction of offshore terminals has already been mentioned. A shipboard regasification concept termed the “Energy Bridge” has been developed by El Paso, a major gas provider in the US. It involves hooking up an LNG ship to an offshore turret transfer system and following vaporisation onboard, the gas is exported onshore via conventional subsea lines.

Where construction of the terminal onshore is acceptable but shipping close to shore is either expensive or a long jetty trestle is not allowed, technology is being developed to run subsea cryogenic lines from an offshore jetty to the storage tanks located on shore.

The design of subsea LNG lines is based in using a pipe-in-pipe solution. The cryogenic line is provided with insulation to reduce heat gain and to prevent freezing of the surrounding water and the insulation is retained by an outer carbon steel pipe. This concept is based on technology developed in the offshore oil and gas industry where hot streams have been transferred between platforms in a similar way for a number of years. InTerPipe [ITP] have patented a design which uses an inner pipe made of Invar for carrying the LNG and special insulation material IZOFLEX. This concept has undergone full-scale prototype testing by Gas de France in 2001 [2].

VII. Conclusions

LNG receiving terminals have been using specialised equipment for years, but there are clearly opportunities ahead to further develop the technology. The interest in moving facilities offshore is high and improving process efficiency is also becoming a high priority. There is little doubt that given the growth in the industry, some of the concepts which have been implemented on a small number of projects will continue to be studied in the future but they will come under increasing scrutiny due cost reduction and environmental pressures.

References

The following references were used in preparing this paper:

[1] Hirose H, TKK, Development of Aboveground Storage Tank Designs in Japan, LNG Journal March/April 2002.

[2] Thermal Insulation for Subsea Pipelines, LNG Journal May/June 2002.