Handling LNG: Storage and Re-Gasification Systems

A Project Report submitted in partial fulfillment of the requirements for the Degree
of
MASTER OF TECHNOLOGY
in
GAS ENGINEERING
(Academic Session 2003-05)

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May 2005

CERTIFICATE

This is to certify that the Project Report on *"Handling LNG: Storage and Re-Gasification Systems"* submitted to University of Petroleum & Energy Studies, Dehradun, by **Mr. Pawan Kumar,** in partial fulfillment of the requirement for the award of Degree of Master of Technology in Gas Engineering (Academic Session 2003-05) is a bonafide work carried out by him under my supervision and guidance. This work has not been submitted anywhere else for any other degree or diploma.

Date: May 23, 05

Dr.B.P.Pandey

ACKNOWLEDGEMENT

Before I get into the thick of the things I would like to add a few heartful words for the people who gave unending support right from begging.

From the inner core of my heart I would like to express my undying gratitude to **Dr. B. P. Pandey** who graciously provided a wealth of invaluable guidance and instructions during the course of the project, which lead to the path of success.

I thank **Dr. Himmat Singh** and the experts from Petronet LNG **Man Mohan Ahuja Vice President (Technical), Petronet LNG Limited** and **Sham Sunder, Director (Technical) Petronet LNG Limited** for the inputs provided by them.

And finally heartfelt appreciation to friends for reviewing the entire manuscript with painstaking attention for details.

Pawan Kumar

Pawan Kumar

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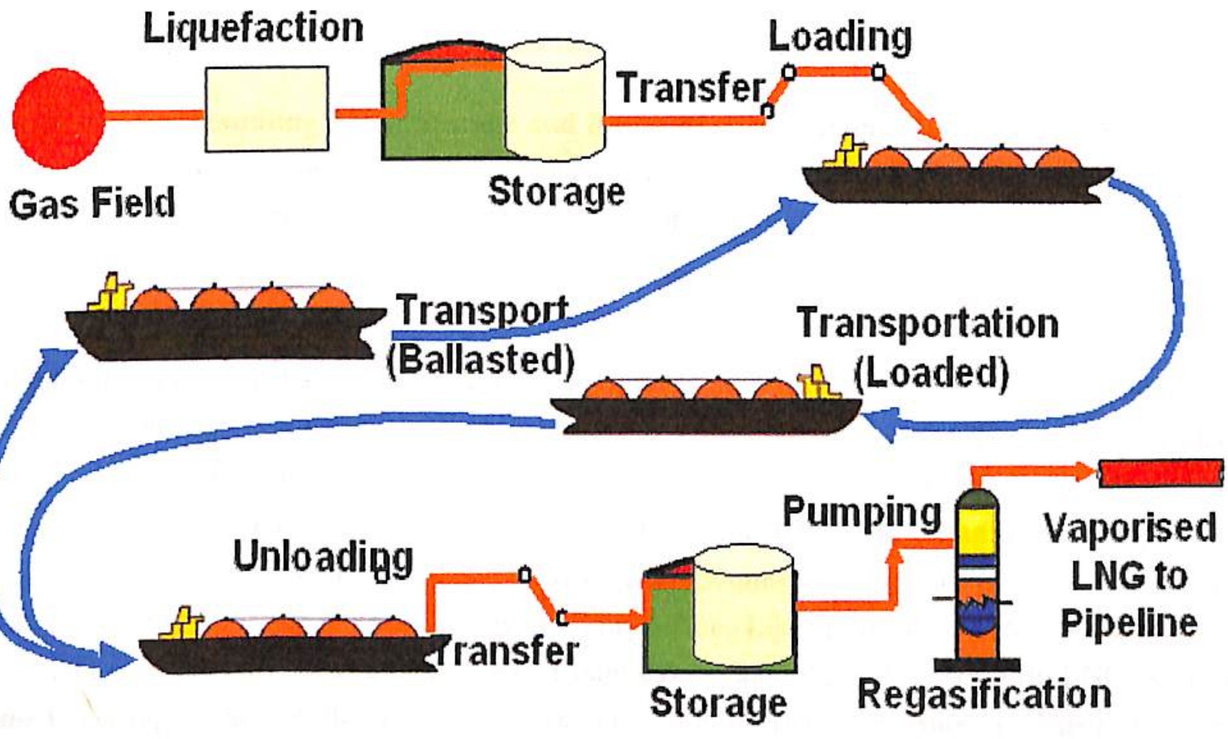


Executive summery

The worldwide community consumes about 90 trillion cubic feet (Tcf) of natural gas each year. Fortunately, natural gas is a resource found in significant volumes worldwide. At the beginning of 2003, the world's known natural gas reserves were estimated at about 5,500 Tcf, roughly 60 times the volume of gas consumed in that year and clear evidence that despite the world's appetite for natural gas, exploration and development efforts have more than met demand.

LNG serves an economic purpose by providing a means for storing large volumes of natural gas in a relatively small space, either to be able to provide it to consumers on short notice [for peaking] or to facilitate its being transported across long distances when a pipeline is not feasible. This second reason is the primary motive behind the international LNG business: connecting natural gas that is "stranded" far from a market with the individuals and industries, which need the energy.

The project work on **Handling LNG: Storage and Re-gasification Systems** includes all the processes of storage of LNG under ground and above ground storage, re-gasification processes of LNG and all other operational aspects which are significant considerations in the design of LNG re-gasification terminal and gives the conclusion towards identification of operationally most dependable and ecnmenically viable strategy for LNG handling and environmental friendliness.

LNG is natural gas that has been condensed to a liquid through a cooling process. The composition of natural gas, and hence the LNG that is formed from it, varies slightly according to its source and processing history, but it consists almost entirely of methane (CH_4), the simplest hydrocarbon compound. Typically, the composition of LNG is 85 to 95+ percent methane, along with a few percent ethane, even less propane and butane, and possibly trace amounts of nitrogen. Water is necessarily removed from the natural gas stream prior to its liquefaction. Like its primary constituent, LNG is odorless, colorless, non-corrosive, and non-toxic. Compressing natural gas does not form LNG nor is it maintained as a liquid through the use of high pressure. At atmospheric pressure [14.7 psi], methane will condense to a liquid when it is cooled to –259 °F (-161 °C).

Cooling the gas to this temperature and keeping the resulting liquid cold allows the LNG to be transported and stored under normal [atmospheric] pressure as a cryogenic [very low temperature] liquid. The density of LNG is less than half that of water, so if LNG were to be accidentally spilled onto water it would float and then vaporize rapidly. An open container of LNG at room temperature and pressure would look and behave much like a container of boiling water.

The liquefaction process reduces the original volume of the natural gas being converted into LNG by a factor of more than 600, which allows for its efficient transport and storage. This shrinkage is roughly analogous to shrinking the gas volume in a large beach ball into a liquid volume the size of a ping-pong ball. Because of this dramatic reduction in volume, just one shipload (138,000 m^3) of LNG can deliver nearly 5 percent (~3 billion cubic feet) of the United States' average daily demand for natural gas.

The global LNG business has been widely described as a "LNG Value Chain" having four links: (1) Exploration and Production, (2) Liquefaction, (3) Shipping, and (4) Storage and Re-vaporization. The Storage and Re-vaporization (import terminal) consist following facilities:

(a) Natural gas consumption and supply sources
(b) An LNG liquefaction terminal and LNG producing process
(c) Marine transportation of LNG – structure of LNG tankers, navigation, unloading operation
(d) City gas producing process from LNG
(e) LNG delivery by tanker trucks
(f) Safety and security of the LNG terminal – structure of LNG tank, gas leakage and other sensors, facilities for safety
(g) Computer control room
(h) Utilization of LNG cold energy in general

Each of these components has its own set of technological challenges and investment criteria, but each is linked to the others in the sense that no one component is a viable business investment without the others. The enormous investments required, particularly in the liquefaction and shipping components, have historically made the careful assembly of this chain a prerequisite for each LNG project; from the delineation and dedication of large natural gas reserves on the upstream end of the chain, to the guarantee of long-term markets on the downstream end.

A typical facility will have tank storage capacity for 2 to 3 ships' cargoes or about 5 ~ 8 bcf at standard conditions (250,000 ~ 380,000 m^3 in liquid form). The terminal will always have a LNG inventory in its storage tanks to keep everything cooled down. Typically the high-pressure pumps and vaporizers are the units limiting send-out as the facility can receive a cargo in 24 hours but takes from 3 to 6 days to discharge that volume as gas to the pipelines.

Two or more above ground tanks are generally installed for receiving and storing LNG. 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 provides 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.

In-tank cameras enable plant operators to assess tank damage in the event of an earthquake and to visually inspect the tank contents in the event of unusual instrument readouts. Fire detection and response systems are in place wherever combustible gas is stored or handled. Facility operators use low-temperature, gas, fire, and smoke detectors, supplemented by closed-circuit television cameras that can identify potentially hazardous situations such as LNG spills and leaks.

The application of conventional salt cavern storage technology, augmented by new technology in the area of pumps, heat exchangers and facility design, could marry LNG and salt caverns into a highly secure, economical, flexible method to expand the Nation's energy supply. Two key differences between a salt cavern based facility and a liquid tank based facility are that the caverns can be miles from the ship offloading facilities, and there is limited cryogenic liquid on site absent a ship. In a conventional terminal the liquid storage tanks must be in close proximity to the ship discharge site and considerable inventory is maintained between ships calls.

LNG terminals are generally sited relatively close to densely populated areas permitting in these locations often proves difficult, moving developers to consider offshore solutions. These offshore alternatives include:

- Floating Storage Regas Units (FSRU)
- Offshore Gravity Based Structures (GBS)
- Converted LNG Carrier (submerged or external turret)
- Platform Based Import Terminals

Whilst none of these alternatives have yet been built, they rely largely on proven technologies. Their technical novelty lies more in the way their various components are integrated into a single working system. As each system possesses different strengths and weakness, the real challenge is to determine which solution is best suited to a particular location

The matching of these solutions to the complexity of the gas market requirements such as gas demand profile, send out pressure/temperature and interruptability of gas supply, when combined with local technical site factors such as metocean conditions and issues surrounding permitting procedures and stakeholder engagement, ensures this selection of the correct import terminal solution is a significant challenge.

To return LNG to a gaseous state, it is fed into a regasification plant. On arrival at the receiving terminal in its liquid state, LNG is pumped first to a double-walled storage tank, similar to those used in the liquefaction plant, at atmospheric pressure, then pumped at high pressure through various terminal components where it is warmed in a controlled environment. The LNG is warmed by passing it through pipes heated by vaporization system. 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. At many facilities an economic design can be achieved by using ORVs for the normal range of sendout and SCVs as spares. 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' utilization process. The vaporized gas is then regulated for pressure and enters the pipeline system as natural gas. Finally, residential and commercial consumers receive natural gas for daily use from local gas utilities or in the form of electricity.

Chapter- 1

Introduction

Chapter- 1

Introduction

1.1 Background

Natural gas is one of the world's cleanest fuels; it's also one of the most expensive to transport long distances. Large volumes of natural gas (i.e. primarily methane) are produced in remote areas of the world. This gas has significant value if it can be economically transported to market. Chilling natural gas to minus 260°F will liquefy and shrink it to one-six-hundredth its volume – turning 600 cubic feet of natural gas into one cubic foot of LNG. This, in turn, allows us to transport LNG at near-atmospheric pressure in specially designed, double-hulled ships with insulated cargo tanks. At its destination, a simple process is used to gradually warm the liquid to convert it back to a gaseous state so it can be consumed as pipeline gas. Introduction to LNG, provides details on the global LNG value chain. The major components of the value chain include the following (see Figure1.1): -

- Natural gas production, the process of finding and producing natural gas for delivery to a processing facility.
- Liquefaction, the conversion of natural gas into a liquid state so that it can be transported in ships.
- Transportation, the shipment of LNG in special purpose ships for delivery to markets.
- Re-gasification, conversion of the LNG backs to the gaseous phase by passing the cryogenic liquid through vaporizers.
- Distribution and delivery of natural gas through the national natural gas pipeline system and distribution to end-users.

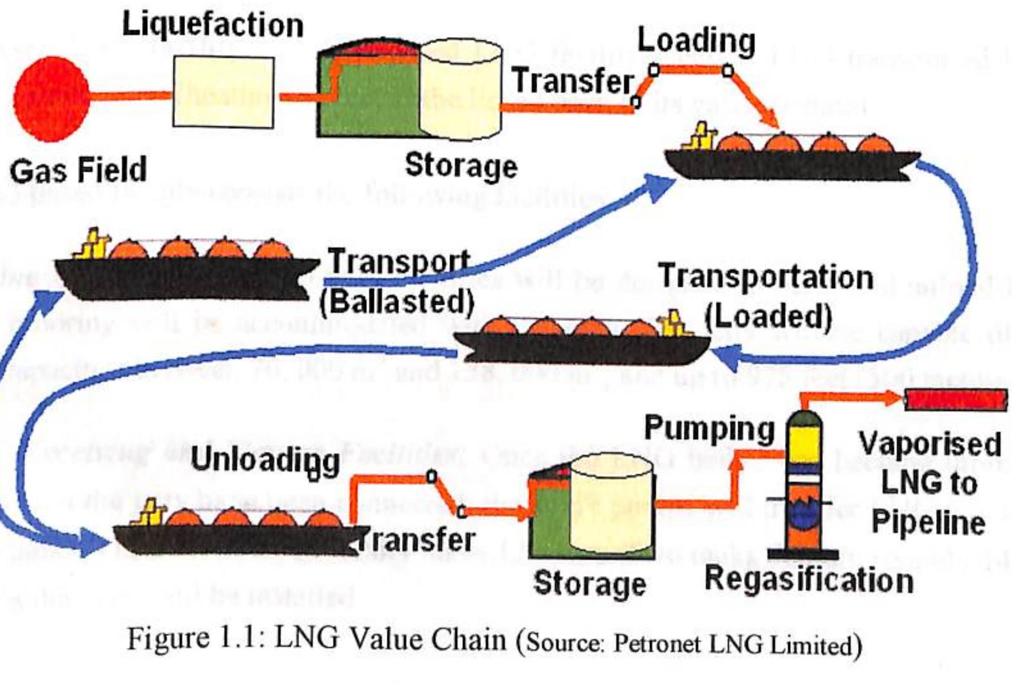


Figure 1.1: LNG Value Chain (Source: Petronet LNG Limited)

Base load LNG liquefaction facilities take a natural gas feed and pre-treat and refrigerate it until it becomes a liquid that can be stored at atmospheric pressure. These large processing facilities, consisting of one or more parallel units ("trains"), include gas treatment facilities, liquefaction systems, storage tanks, and LNG transfers terminals.

For transportation of LNG, it is pumped from storage, through water loading facilities, to ocean going vessels suitable for the long distance transport of such a specialised cargo. LNG is differs from most other bulk cargoes in a number of respects. Roughly by order of importance in regard to sea transport these are:

- It very low temperature (about -160^0C);
- Its low density (0.43 g/cm^3);
- Its high latent heat of evaporation (at -160^0C this is about 535KJ/kg);
- Its low viscosity;
- Its inflammable nature (5-15 vol % in air forms explosive mixture)

Handling LNG: Storage and Re-Gasification Systems is mainly concern with LNG import terminal of LNG supply chain. The types of LNG import Terminals are Land-Based, Converted Offshore, Floating Storage and Regasification Unit (FSRU) Platform.

1.1 Land-based LNG facility: - A land-based LNG facility receives LNG transported by ship, for storage and regasification (heating to convert the liquid back to its gaseous state).

A typical land-based facility consists the following facilities: -

1.1.1: - ***Marine Facilities***: The LNG jetty facilities will be designed to berth and unload LNG ships. LNG tanker mooring will be accommodated with tugboats. The jetty will be capable of unloading tankers with capacities between 70, 000 m^3 and 138, 000 m^3, and up to 975 feet (300 meters) in length.

1.1.2: - ***LNG Receiving and Storage Facilities:*** Once the LNG tanker has become moored and the unloading arms on the jetty have been connected; the ship's pumps will transfer LNG into the onshore LNG storage tanks. The offloading generally takes 12 hours. Two tanks that are roughly 145 feet high and 240 feet in diameter will be installed.

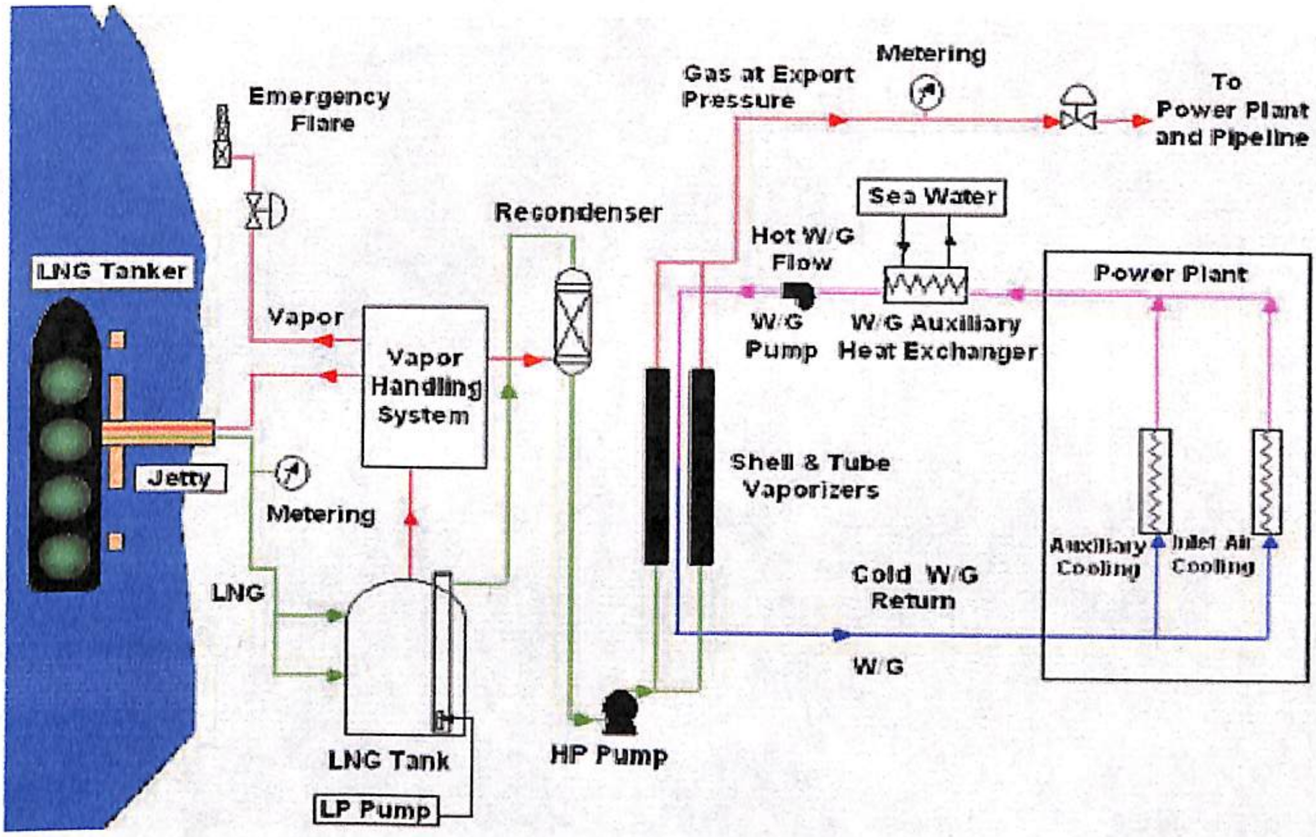


Figure 1.2: Schematic for a typical LNG Import Terminal
Source: bp, http://www.bplng.com/products/services_tech.asp

They will operate at atmospheric pressure and are well insulated to keep the LNG at -256° F. The LNG storage tanks are designed specifically to contain the LNG, and will be built as a two-wall tank, with the first wall made out of high nickel steel that prevents low temperature failures. The outer wall is made out of concrete.

1.1.3: - *Vaporization Facilities:* Each LNG storage tank will contain send-out pumps that will transfer the LNG to the vaporizers. The LNG is so cold that seawater at roughly 59°F (15° C) can be used to pas across the cold LNG and vaporize it to a gas.

1.1.4: - ***Supporting*** *Utilities:* The plant will have extensive safety systems to detect LNG spills utilizing a number of gas detectors, fire detectors, smoke or combustion product detectors, and low temperature detectors. These sensors are equipped with automatic valve and machine shutdown mechanisms that isolate spills and shut down equipment.

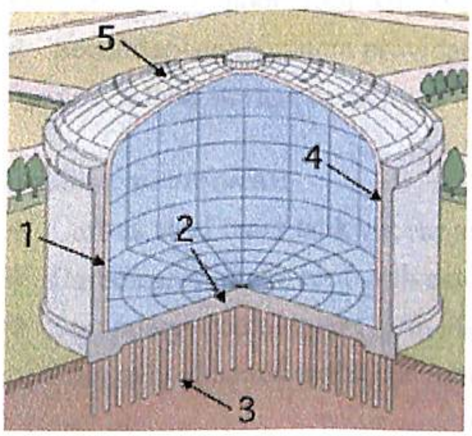
1.2 Handling LNG: Storage Systems

Storage facilities for LNG are required weather the liquid is to be used to meet winter shortages of the gas or to supply base load gas by long distance shipment. In the letter case complete ships cargoes have to be loaded into and from LNG tankers, i.e. storage capacity must be at least equal to the maximum volume of LNG expected in any shipment. On other hand storage for peak shaving depends on the number of days per year during which gas is to be liquefied – 200 to 220 in a temperate climate- and on the daily capacity of the liquefaction plant.

The vessel or spaces used for storage will constantly loss refrigeration i.e. there will be heat leakage inwards and its extent will depend on the insulating quality of containing walls. Rate of vaporization or boil off is a measure of heat leakage, and in order to design LNG storage facilities correctly it is essential to predict the heat gain of the liquid.

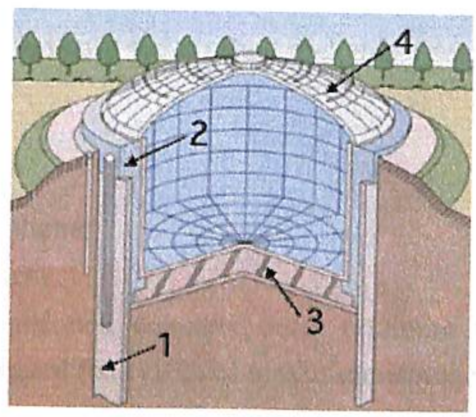
There are basically two types of LNG (liquid natural gas) storage tanks:

- Above ground LNG storage tanks
- Under ground LNG storage tanks



1. Exterior tank liner
   (prestressed concrete wall)
2. Basemat slab
3. Steel pile
4. Interior tank liner
5. Exterior tank roof

Figure1.3: Above ground storage tanks



1. Continuous diaphragm wall
2. Side wall
3. Basemat slab
4. Roof

Figure 1.4: Under ground LNG storage tanks

Source: Takenaka Corporation (http://www.takenaka.co.jp/takenaka_e/engi_e/)

The other way of categorization of typical of LNG tanks are:

1.2.1 Large-scale LNG storage tanks are usually constructed as freestanding tanks, membrane tanks or buried tanks. Freestanding tanks are flat-bottomed, vertical, cylindrical tanks for low temperature services. Basically three tank design principles prevail:

a) Single containment,
b) Double containment
c) Full containment.

The main features of these concepts are; freestanding inner tank and bottom in 9% nickel steel and aluminium suspended deck, with all penetrations from the tank roof. Pumps are either supported from the tank base (as for type a+b) or from the roof (type c). The insulation material is usually perlite. Further specific features:

(a) Single containment:

- ❖ Carbon steel outer tank vapour and insulation container
- ❖ Carbon steel dome roof with external deluge system
- ❖ Secondary containment provided by composite sand core and crushed rock dikes designed for 110 % tank storage capacity

(b) Double containment:

- ❖ Carbon steel outer tank vapour and insulation container
- ❖ Carbon steel dome roof with external deluge system
- ❖ Secondary containment provided by a post-tensioned concrete outer retaining tank wall, integrally attached to the concrete base slab, designed for 110 % of maximum storage

(c) Full containment:

- ❖ Pre-stressed concrete outer container with steel liner
- ❖ Concrete covered steel roof
- ❖ Liquid spill area limited by outer concrete wall

The diameter of base- load storage tanks is usually 65-85 m, with a dome- height up to 48 meters and 37-38 m jacket height. The building of such tanks is a highly specialised undertaking.

1.2.2 Engineered vertical and horizontal stationary storage tanks are typically designed for a capacity in the range from 60 to 500 m^3 and maximum allowable working pressure up to 24 bar for long-term storage of LNG.

The insulation is usually vacuum-perlite based with a molecular sieve absorber in order to minimize the loss of stored products. The engineered tanks can be supplied with external vaporizers, - either product, ambient or steam heat vaporizer, and vacuum insulated pipelines and other cryogenic components that are required to create a complete installation. The inner vessel is in stainless steel. The outer jacket combines leg and lifting lugs and is designed for transport, easy lifting and low cost erection. The piping is made from stainless steel. The pressure control is a multifunction regulator, economizer and thermal- relief valve.

Liquefied natural gas (LNG) on shore can be stored in cryogenic tanks i.e. aluminum or nickel steel inner vessel or membranes, surround by insulation and external weather proofing In addition pre-stressed concrete tanks can also be erected above ground, or can be cast below the surface. Finally existing caverns or under ground spaces specially prepared for the LNG storage can be used. The main advantage of in-ground storage tanks, both concrete and natural, is that they do not required contaminant dykes to collect product from leaking or burst containers. The attraction of above ground storage tankage on the other hand, is improved control of heat leakage and also possibilities of repairs.

LNG Storage can be classified into another way also as following: -

- Metal Tanks
- Prestressed concrete vessels
- Frozen ground and cavern storage

1.2.3 Metal Tanks: -

For storing the cryogenic temperature liquid (LNG) it necessary to provide aluminum or stainless or at least 9% nickel steel membranes to contain the liquid and prevent it from making contact with external metal walls. A layer of insulation backs the gas-impermeable membrane, below the tank bottom insulation has to be of load carrying capacity verity. Insulation between the two vessels must be sufficient to prevent the cooling of the outer walls, and it is essential that the insulating space should be free of moisture to prevent ice build-up and loss of insulating power. It is also important to prevent the extremes of temperature affecting the foundations. Freezing and subsequent melting of the soil below the tank must be prevented by a combination of lagging of the tank and electric heating of the soil. Foundations for the storage tanks depend on soil conditions and tank size. For the larger tanks the main alternatives are either piling or a concrete ring beam, the former used where soil are soft, the letter, which is cheaper, where ground rock is not too far and the soil can be heated to prevent frost heave inside the ring.

The inner membrane of the tank can be produced in a number of alternative fissions. Since powder insulation in a double skinned vessel is subjected to thermal movement and consequent compacting it is important that any motion in the inner skin be taken in some way. In the case of smooth membrane a fiberglass blanket does this, which is sufficient elastic to allow for inner tank expansion and contraction without transmitting any pressure to the outer powder insulation. Alternately the inner skin can be made of corrugated aluminum, which can be braced against the outer wall by ties of insulating material.

The third and most expensive means of stabilizing the inner skin and protecting the insulation layer, is to use Invar, the 36% nickel steel which suffers practically no thermal expansion over the range of –160^{0}C to +30^{0}C. Construction of the roof is possible in a number of ways. Since LNG temperature is close to the boiling point floating roof tanks are clearly out of the question. Similarly, freely vented fixed roof tank cannot be used since explosive mixture of air and gas could be easily formed. It is therefore essential to ensure that LNG tanks withstands a modicum of pressure or vacuum, and pressure roof tank for LNG must be designed to contain atmospheric pressure fluctuations, the withdrawal of boil-off gas from under the roof by re-liquefaction compressors and then vapour pressure fluctuations which will occur owing the change in LNG temperature, e.g. sub cooling below its boiling temperature, or change in composition. The roof of the inner tank is normally an aluminum skin stretched between structural aluminum members. It is suspended by a large member of hangers from the outer dome and capable of supporting a layer of expandable perlite or similar insulation. A reinforcing metal ring round the circumference of the roof is designed to resist compacting force exerted by the powder insulation between the two skins.

An alternative method of construction, which promises to reduced the cost of LNG double skin tankage is to replace the inner metal roof by suspended layer of insulation which is slung from the undersize of the outer tank roof. In such a structure gas is no longer confined to the inner tank but the outer vessel is used to contain the pressure of the gas. The weight of metal LNG tank is insufficient to ensure stability and the tanks have to be bolted down to the foundation in order to prevent lifting and movement when they are empty, i.e. filled only with natural gas.

In the case of tank with complete membrane separation between the inner LNG container and the outer supporting vessel this means that the retaining bolts must be spaced around the circumference of the inner vessel-in the light of unsatisfactory mechanical properties of the most steel at low temperature this implies the use of stainless steel of at least 5% nickel content and a very careful welding procedure. Filling the insulation with methane gas, on other hand permits locating all retaining bolts on the out side of the vessel, where there are no longer exposed to the low temperature of the tank content. In the other words since there is then no pressure difference outer and inner vessel it is sufficient to bolt the former in position, letter is being held purely by the insulation and bracing ties between outer and inner containers.

1.2.4 Prestressed concrete vessels

In this type of LNG storage special types of concrete are used to prevent cracking by thermal stress. It is important to reinforce with high-tension wire or rods under tension, i.e. prestressing or postressing. In practice the problems encountered with in ground LNG storage has been formidable. Particularly very large tanks, and clearly the larger the volume/ surface ratio the more efficient this form of storage becomes, have failed owing to crack formation in the rock and frozen soil at the wall surface; heat transfer has exceeded calculated values owing to ingress of water, particurly where tidal water movement occurs.

An above-ground LNG tanks in concrete, on the other hand, has been successful in a number of instances. Construction technique usually consists of erecting (vertically) prestressed concrete panels to forms the side walls. These are than wound circumferentially with high tensile wire, around which further concrete is poured while the wire is under tension. The resultant structured is covered with a metallic, prestressed concrete or glass reinforced plastic domed roof and insulated either on the out side with powder (perlite) insulation filling the space between and outer metal skin, or on the inside with load-bearing insulation faced with a gas-impermeable flexible membrane in contact with the LNG.

The use of reinforced concrete for cryogenic structures is justified since its tensile strength is actually higher at low temperature; the reinforced steel, in spite of an increase in brittleness and a lower notch strength and ductility, is in fact higher in tensile strength, and when protected from impact by a layer of concrete, is capable of withstanding all expected mechanical and thermal stresses. An important consideration in the construction of concrete LNG storage tanks, is the avoidance of moisture penetration into the insulation space between outer and inner shells and also, if a leak develops in the inner barrier, to prevent LNG penetration into the concrete with result ice formation and possible structural damage.

Recently a mastic coating, to be applied to the interior surface of the concrete, has been developed which, it is clamed, prevents both gas and water vapour leakage. A further advantage claimed for the product is that it reduces or eliminates the propagation of cracks in the concrete. These types of tanks can be built with several variations:

- Earth or pile supported foundations
- Concrete outer shell and roof (as shown below)
- Concrete outer shell with steel roof
- Separate concrete wall for secondary containment
- In-ground or mounded secondary containment

1.2.5 Frozen ground and cavern storage

LNG can also be stored in natural or artificial caves or covered pits. The procedure for excavating cryogenic storage is seemingly easy. First the ground is solidifying by forming a base plug and cylindrical wall by circulating refrigerated brine through freeze tubes. While the outer freeze tubes are retained during subsequent mechanical excavation and the frozen wall prevents water penetration from the sides, the plug tubes have to be withdrawn and the bottom of the pit refrozen when excavation is completed. The roof of the pit is supported by a concrete ring beam on concrete foundations around the lip of the pit. The roof is itself is constructed in aluminum, with a self-supporting membrane faced insulation suspended on the side and extending underneath the concrete support. Alternately insulation can be on the out side, or the roof can be hanged from a steel doom. Problem with this type of storage are among others:

- Movement of the ring beam and its foundations due to delayed frost heave;
- Movement of pipeline trestles and pipes due to delayed soil shrinkage around the tank;
- Higher than excepted boil-off rates due to irregular freezing of the vessel walls.

They are accentuated by certain types of soil, and particularly by hetrogeneneity of soil structure. Thus different strata containing widely different concentration of water can result water migration and consequent soil movement. Similarly tidal water that enters the storage area periodically can interfere with frozen ground tankage and its stability.

Commissioning of frozen earth storage must therefore takes place over an extended period; in one installation it took 70 days to cool the tank down to LNG temperature by means of spraying, followed by a period of 90 days during which the liquid level of the tank was raised. Boil-off which mainly caused by heat in-leakage, is at first a function of spraying rate, then increases gradually as the LNG level rise and eventually falls off to its equilibrium value as the frozen soil wall thickness increases.
As in ship borne and other forms of LNG tanks, pipe works, pumps, instruments etc. are introduce from the top of the tank. Submersed pump/ driver combinations are suspended from the roof supports and both pump and instruments have to be highly reliable so as to reduce overhaul frequency and consequent heat leakage to the absolute minimum.

A from of construction which is intermediate between in-ground containers, i.e. frozen holes, and above ground metal tanks, is the in-ground container built originally above ground but subsequently surrounded by a soil berm which slopes naturally away from the tank, or occasionally, is retained by a supporting wall.

If this berm has a minimum thickness of 10ft, the container gas no longer considered an above ground tank with corresponding safety slandered, and does not require containment dykes and enlarged safety distances. Forth more this type of construction permits better insulation and much lower vapour losses to be attained and eliminates the danger of seepage due to earth movement, tidal water flow etc. In facts some of the world's biggest and most recent LNG storage schemes appear to favour this type of construction, although a recent major explosion during cleaning ànd repairs of such a tank has occurred.

The use of mined or natural caverns suitably lined to prevent LNG seepage into the ground is even less common than successful in-ground storage. While mined caverns can be located in appropriate areas, provided suitable geological strata are present and faulting is limited to cracks which can be filled, natural caverns will really occur in locations where there is demand for stored natural gas which are also accessible to transportation capable of carrying imported LNG.

1.3 LNG Handling: Re-Gasification Systems

Vaporization for LNG are basically heat exchangers, the hot fluid being either combustion gases- in direct equipment- or steam or hot water- in indirect heated vaporizers. Very large vaporizers can, in the absence of a source of steam or hot water, also be heated by cooling water. In the letter case a large supply of water, generally river, estuary or seawater, is required so as to avoid excessive cooling of the heat source. In particular, freezing of the cooling water must at all times be avoid, one method being the use of an intermediate heating fluid such as propane.

The usual practice is to pass LNG vertically upward through pipes embedded in aluminium panels, which are suspended from a steel structure. Fresh cooling water is pumped to the top of the panel and runs down from a trough along the side of panel, to be collect in a pond beneath, whence it is returned to the river or estuary. Internal pressure varies from 7 to 75 atm and plant capacities of up to 60 ton/ hr of LNG have been designed. To prevent freezing and ice formation on the tubes 0^0C, for the seawater *of* -2^0C *freezing point, is the lowest permissible exit temperature.*

A recent improvement design for running film plate exchangers, which is claimed to be more economical in terms of heat flux per unit investment, is based on corrugated stainless steel sheets, spot weld in such a way that once internal gas pressure is applied they will inflate to from pear-shaped channels. The plates are heated externally by cooling water (or an intermediate heat transfer medium) and LNG is vaporized and superheated as it flows horizontally through each heat exchanger pass.

An alternate design, the indirect or intermediate fluid vaporizer consists of a steel vessel, which is half filled with liquid propane at a pressure of about 4 atm and at a temperature of -1^0C. The vessel also contains two heat exchangers, one for seawater, located in the lower half of the vessel, the other fir LNG, which is suspended in the vapour space.

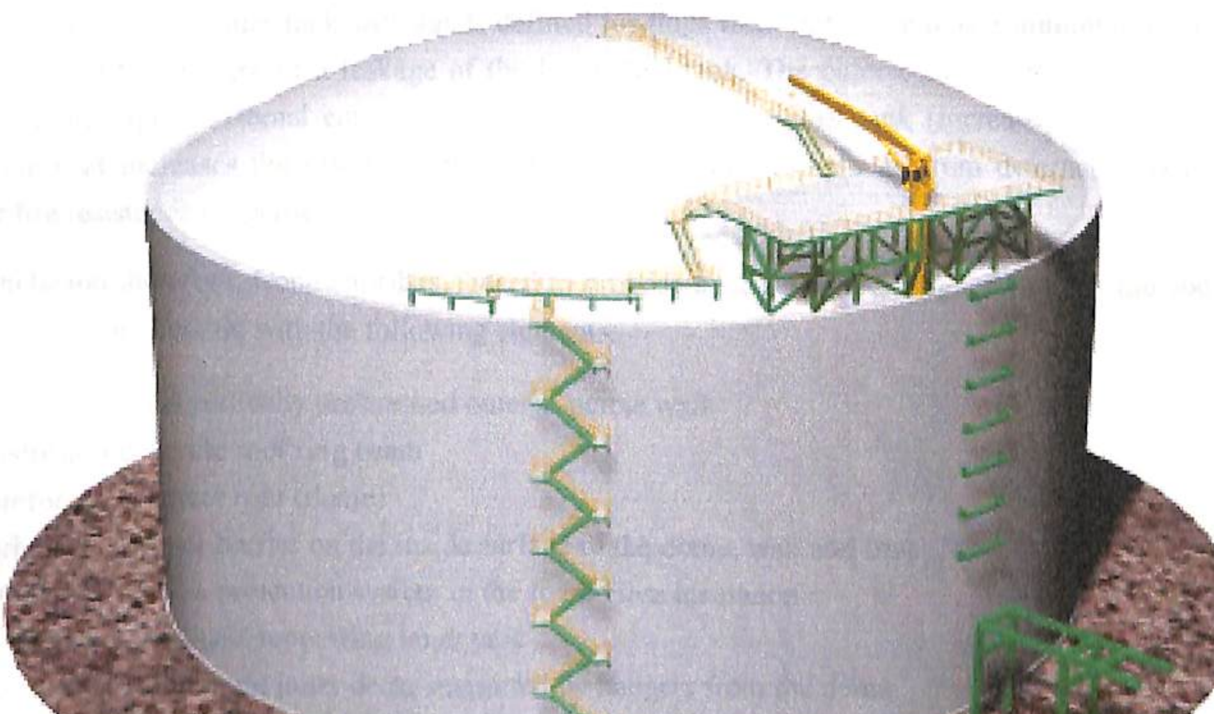
In the most common version of such an intermediate fluid vaporizer the LNG heat exchanger is made up of aluminium alloy tubing in the shape of double hairpins which are weld into aluminium headers and through which the liquid is passed, while propane vapour condenses on the out side of the tubes and on the fins. The sea water heat exchanger also consist of an aluminium tube bundle, but the tubes are straight and are expanded into mild steel plates which bolts to manholes at each end of the pressure vessel. Since the maximum LNG temperature, which can be attended in propane, cooled heat exchanger is about -50^0C it is generally necessary to heat the LNG vapour further, e.g. by passing through slandered tubes and shell heat exchangers with the gas flowing through the sell and sea water in the tubes. A slandered practice is to release the gas at 0^0C and up to 75 atm pressures.

When using a heat medium other than water or propane the temperature difference between heat source and LNG becomes even more pronounced. Heat transfer coefficients are reduced, mainly owing to the formation of a vapour barrier on the LNG side, a phenomenon known as film boiling. Increasing turbulence can reduce the tendency to film boiling. In the design of so called high performance evaporators, for instance, it was found that the installation of corrugated multi fin coils improved heat transfer by a factor of ten.

If heating medium is hot water a definite improvement in heating efficiency can be achieved by restoring to submerged combustion by introducing pressurised gas and air below the water surface can be obtained a more rapid heat exchange between combustion gases and water, and furthermore since all the water vapour in the combustions products condenses the gross rather than the net calorific value of the fuel can be utilized. In situation such as vaporization of LNG where the temperature of heating medium is relatively unimportant, it is clearly possible to use submersed combustion to heat the transfer fluid and exploit its advantages.

Chapter- 2

LNG Storage tank and Design Features



Chapter- 2

LNG Storage Tank and Design Features

2.1 General

The selection of a particular tank system depends on location, environmental considerations, operational conditions, safety and economic efficiency as most important ones. Taking these factors into account, Contractor has set the following criteria when considering the type of to be proposed:

- Safety of personnel, operational safety of tanks and associated equipment
- Reliability, ease of operation and maintenance, and efficiency
- No detrimental effects to the environment in case of an accident

In the type of a full containment tank system the inner steel tank is able to contain the LNG without other support. In case of damage of the outer wall by defined external impact the inner steel tank can retain the LNG. The outer tank withstands defined loadings from outside and as a minimum contains most of the LNG in case of a leakage of the inner steel tank. The outer concrete wall is capable of withstanding higher external emergency loadings than an outer steel tank (increase of safety). The concrete roof increases the safety again. It is less susceptible to damage from external forces, has better fire resistance properties.

In conclusion therefore, Contractor has chosen to propose a storage tank designed to meet the above-mentioned characteristic with the following elements:

1) Horizontally and vertically prestressed outer concrete wall

2) Prestressed concrete roof ring beam

3) Reinforced concrete roof (dome)

4) Carbon steel vapor barrier on the inside surface of the dome, wall and base slab

5) Corner and bottom protection system in the foam glass insulation

6) A 9% nickel steel self supporting inner tank

7) A suspended aluminum inner deck, supported by hangers from the dome

8) An insulation system between inner and outer container which maintain 0.075 wt % / day boil off rate

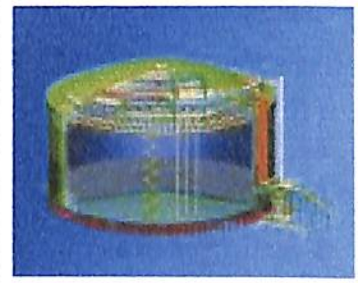
9) Steel platforms, staircase, stairs and caged ladder

10) All tank internal piping, including pump column, LNG stand pipe, spray ring, level instrument & LTD system stilling well and N2 purge system

11) All nozzles and manholes

13) Process, N2, and instrument air piping
14) Cold insulation system for process piping
15) Fire fighting system including:
    - Water spray system
    - Dry-chemical extinguishing system
16) Fire proofing system
17) Safety valve system
18) All electrical work within the battery limit
19) All instrument work within the battery limit
20) All painting and coating work within the battery limit

2.2 Design feature



From the point of safety a double wall LNG-storage-tank with a 9% nickel steel inner wall, prestressed concrete outer wall, vapor barrier on inner surface of outer wall, concrete roof and bottom with corner and bottom protection system is an effective and on a long-term basis also economic solution.

The design of LNG-storage tanks is governed by the very low (cryogenic) temperature of about -162^0C of the stored medium LNG. The inner steel tank has to withstand the liquid pressure under these cryogenic conditions during normal operating conditions during the whole lifetime. A special steel alloy with 9% nickel is required to achieve sufficient toughness to arrest a fast running crack even at -170^0C. Under service conditions the outer concrete containment has

- To retain thermal insulation
- To act as gastight barrier between the ambient air and the gaseous methane within the insulation and in the roof space
- To act as foundation slab for the inner steel tank

More important for the design of the outer concrete tank are the emergency conditions:

- Liquid spill
- Earthquake
- Missile impact
- Heat radiation
- In tank fire

In the case of liquid spill when the inner steel tank is damaged and leaks, the outer containment has to retain the cryogenic medium. In addition to the liquid pressure an overpressure, resulting from the immediate evaporation of LNG on coming into contact with the concrete wall having the temperature of the environment, has to be retained by the outer wall. These loadings require a prestressing of the wall in horizontal direction. In vertical direction the prestressing will be needed to control the overpressure resulting from the evaporating LNG during operation. Without a LNG-tight insulation-liner the temperature drop-off in the concrete wall causes a centric shortening on the wall. This is restrained by the bottom slab and to a minor extent by the dome. Keeping integrity and tightness of the outer tank at the intersection between wall and bottom slab requires a 9% nickel steel corner protection and bottom liner will be provided as a structural measure in order to restrict temperature gradients, restrained stresses and crack formation to a controllable magnitude at this load case.

2.2.1 Tank sizing

The tank size has been decided based on the following factors:

- Results from seismic analysis of earthquake loads
- Hydraulic requirements

According to the seismic analysis to earthquake loading, the expected intensity of this loading is high. Therefore, Contractor selected a tank with a larger diameter in order to distribute the loads to a larger area. A larger diameter results in a smaller height with its economical advantages.

2.2.2 Inner container

Regarding shell plate and bottom annular plate, the thickness calculation of these plates was done based on API 620 Appendix Q. The results were verified with a seismic design calculation, which was done according to API 620 Appendix L, using the OBE and SSE acceleration response. A minimum 10mm thick 9% nickel shell is installed on the insulation system. The thickness of shell plate is basically determined by internal pressure of contents. After determination, compressive force on which act shell during an earthquake is verified to meet specification. The annular plate, which is thinner than the thickness of bottom shell course, is also installed.

2.2.3 Vapor barrier system

A carbon steel 5mm thick vapor barrier is installed at inside surface of the concrete wall and bottom plate. Contractor has selected a carbon steel vapor barrier, since the steel is obviously more effective than a nonmetallic vapor barrier for moisture impermeability and easier to control during construction. The steel vapor barrier is also an economic solution.

2.2.4 Bottom protection

A secondary minimum 5mm thick 9% nickel bottom is installed on the insulation system. The secondary bottom is extended into the annular space and connected to the 9% nickel wall liner plates. L shape is inserted in the connection part to the vertical shield plates to secure their connection tightness.

2.2.5 Roof liner

A carbon steel 5mm thick roof liner is installed at inside surface of the concrete roof. The liner functions as integral part of the concrete roof using shear anchors for load transfer. The roof is used as framework for the concrete placing.

2.2.6 Suspended deck

The suspended deck has open vents to ensure equilibrium of gas pressure on both side of suspended deck. At the edge of the suspended deck, near the inner tank shell, a partition, is installed to allow storage of more than 2.5% of total annular space volume of perlite powder and to prevent the perlite from flowing over and on the suspended deck. The corrugated aluminum deck is 1.2mm thickness

2.2.7 Pump well

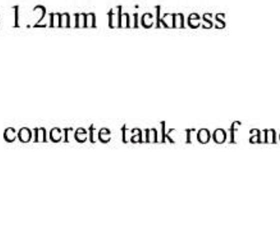
Three pumps well are installed in a tank. The pump well is supported from the concrete tank roof and guide from the inner tank at lowest part of it.

2.2.8 Safety valves

(1) Pressure relief valves: - 3(three) pressure relief valves (set pressure 265 mbar G) are provided and connected to flare for each tank (one is spare). In addition above, 3(three) pressure relief valves (set pressure 290mbarG) are provided for emergency use. These valves release the gas directly to the atmosphere for each tank (one is spare).

(2) Vacuum relief valves: - 6(six) vacuum relief valves (set pressure? 5mbarG) are provided (one is spare). Since outer tank will be made of concrete, operation range of this tank is more widely, safety and economical compared with a tank having a steel roof.

2.3 Civil work



2.3.1 Basic description of outer storage tank

PC outer tank is able to contain the liquid LNG and boil off gas in the event of a rupture of the inner tank. Outer wall is able to keep the entire amount of LNG (=140,000 kl) in the event of leakage. The dike is not needed for full containment tanks.

2.3.2 Type of outer tank

The tank structure is the double wall tank with by 9% Ni steel inner wall, prestressed concrete outer wall and vapor barrier on inside of outer wall. The outer roof is made of reinforcing concrete and has a spherical form. The steel liner is located on the inside of the roof for vapor barrier and functions as formwork during construction. PC outer wall is connected rigidly to both bottom concrete slab and outer concrete roof. The foundation type of tank is pile foundation by steel pipe piles. The inner surface of vapor barrier on outer wall is covered by cold resistance relief (PUF: Poly-Urethane Foam). In case of liquid spillage from the inner tank, outer tank holds 140,000 kl of LNG for each tank.

2.3.3 The components and function

1) Foundation

Foundation type of tank is the pile foundation driving into bedrock formation. It supports the tank, PC outer wall, bottom slab and outer roof in all load condition. Also, it is stable for long-term settlement.

2) Bottom slab

Bottom slab is the reinforcing concrete structure to install on the ground directly with brine heating system. It supports the tank, PC outer wall and outer roof in all load condition.

3) PC outer wall

PC outer wall is prestressed concrete structure with vapor barrier and PUF insulation on inside. When inner wall is able to perform that safety and operation function, PC outer wall supports outer roof, and it maintains pressure of side insulation and gas pressure. When content liquid leaked all quantity from inner wall, it is safe structure to liquid pressure and thermal load. The top part of PC outer wall is the ring beam, which is prestressed, and maintains the horizontal load by RC roof weight.

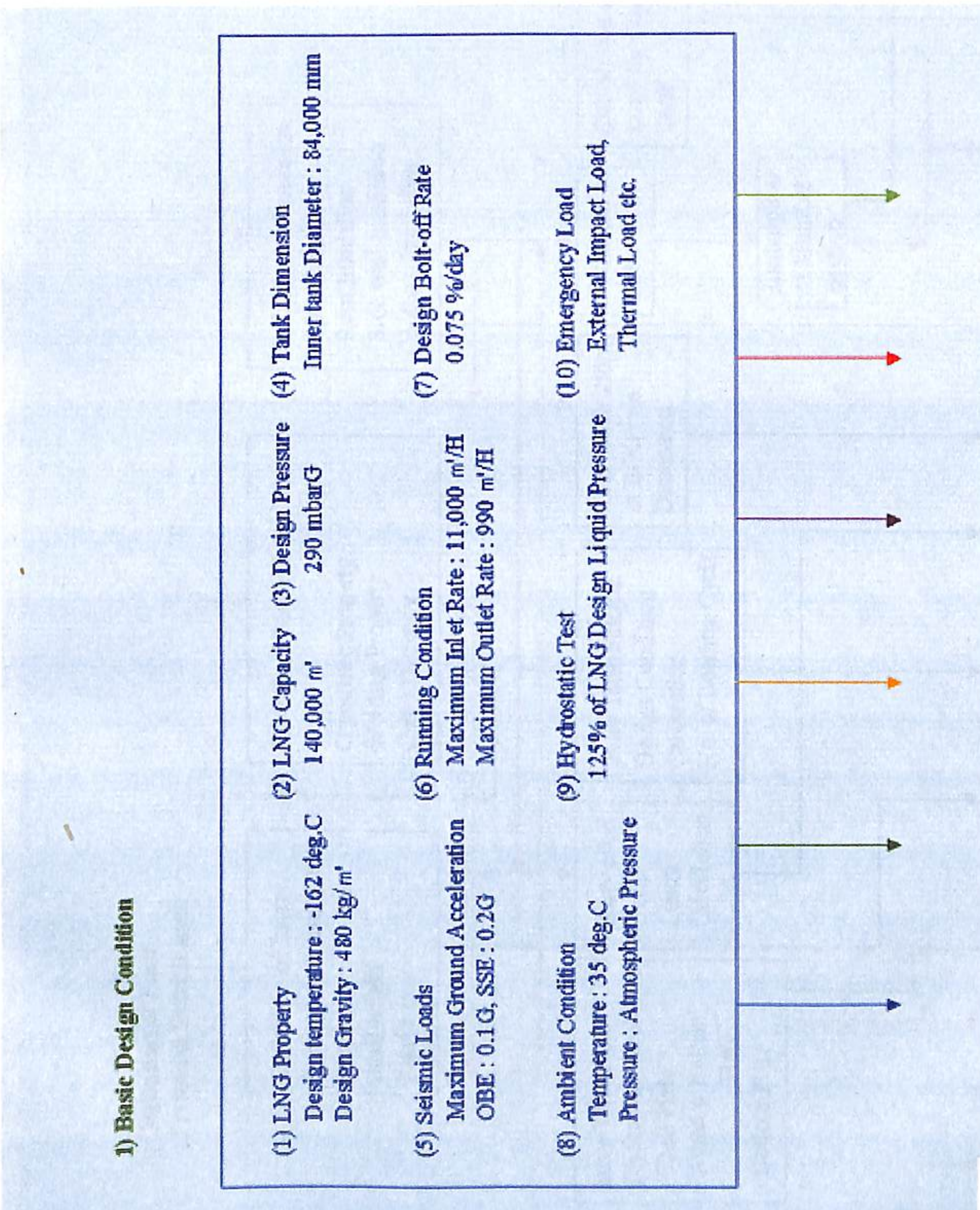
4) Outer roof

Outer roof is concrete structure with steel cupola. It supports suspended deck and it is safe structure to gas pressure.

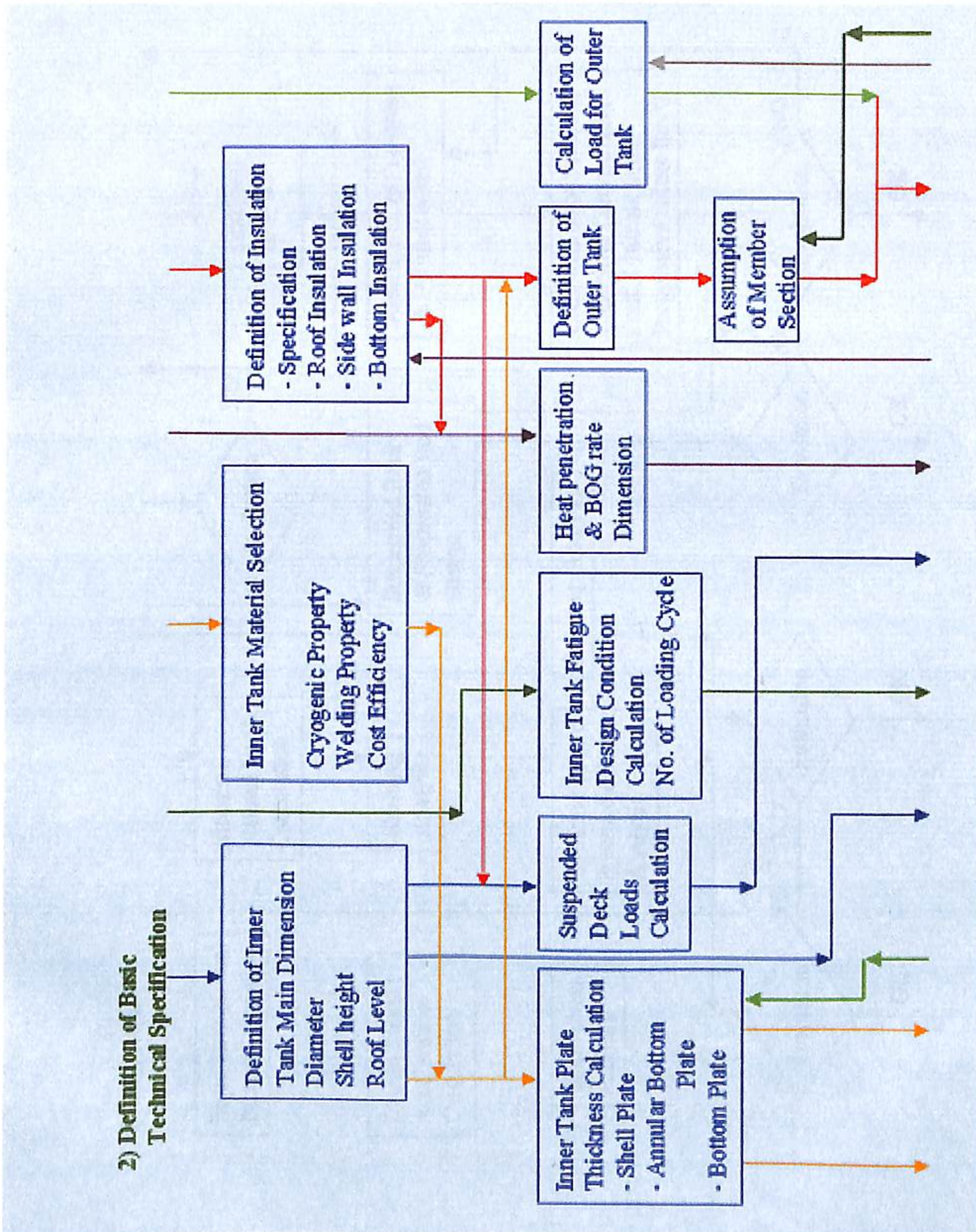
5) PUF insulation

PUF insulation which is situated on the inside surface of the vapor barrier, it is sprayed PUF structure protecting glass mesh. It maintains liquid pressure and thermal load acting PC outer wall after leakage. The analysis of feasibility of LNG Storage tank design is given on the next page.

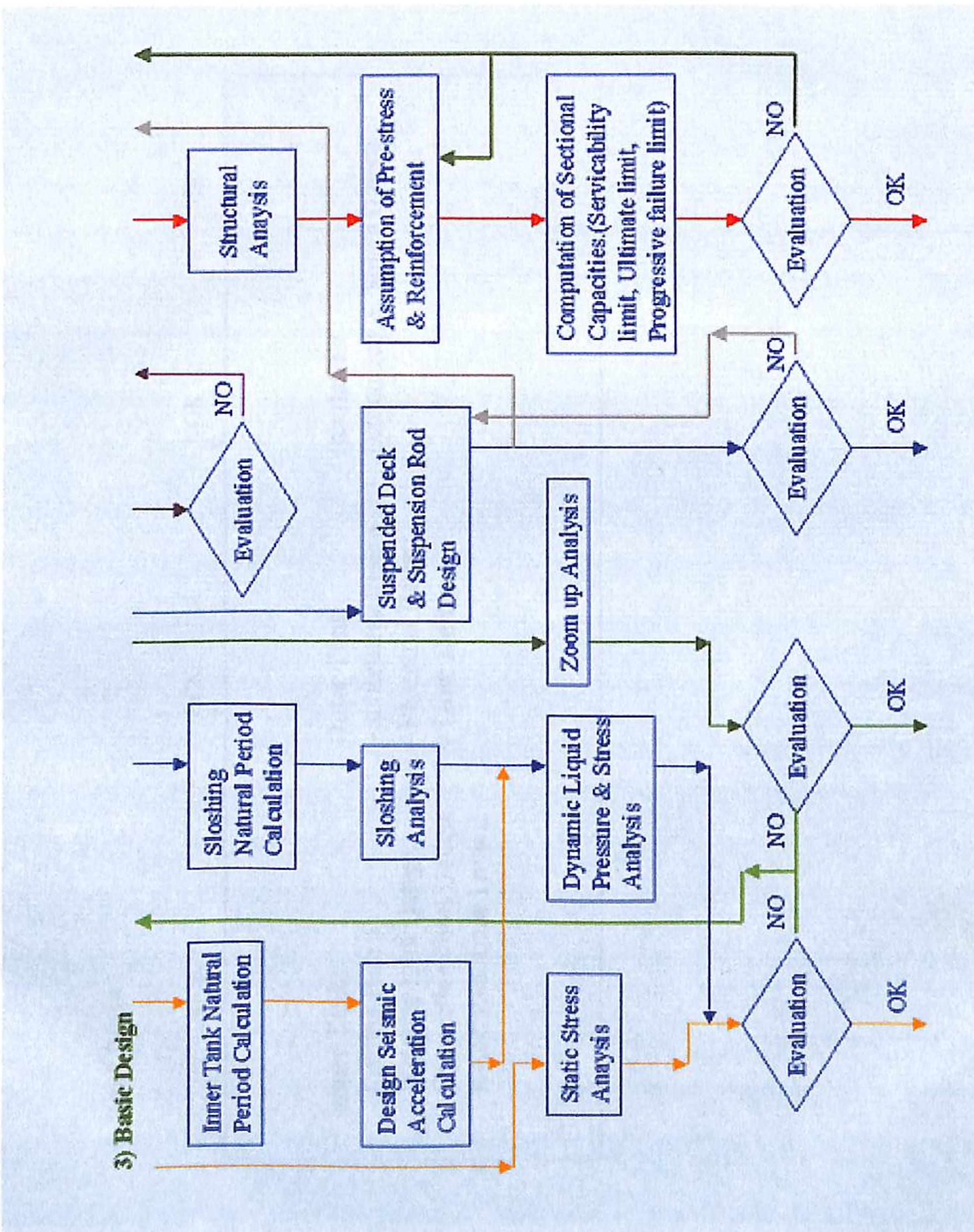
2.4 Full Flow Chart of basic design of LNG storage tanks



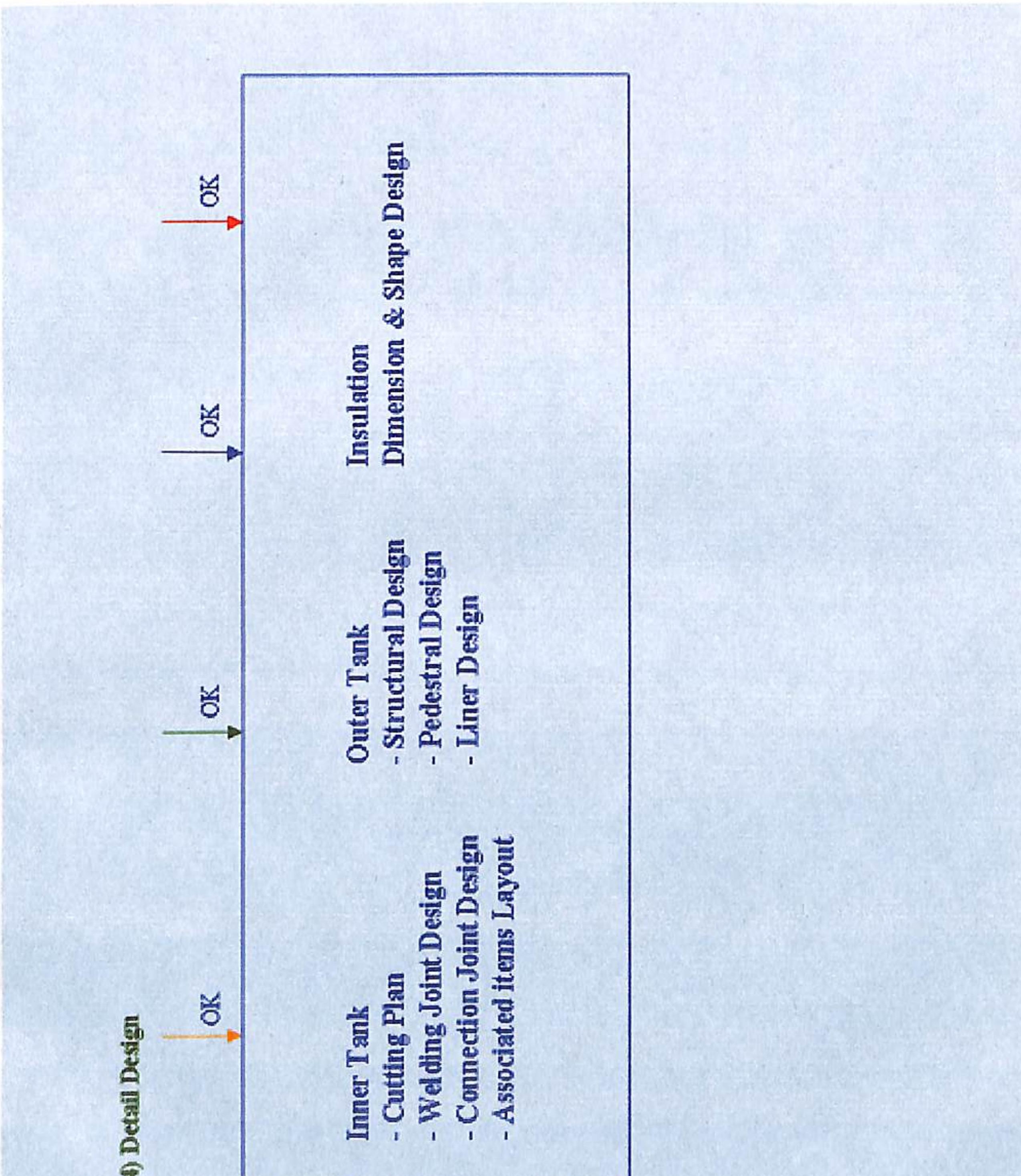
Source: Daewoo E&C Co., http://www.plantconst.com/lng/index.html



Source: Daewoo E&C Co., http://www.plantconst.com/lng/index.html



Source: Daewoo E&C Co., http://www.plantconst.com/lng/index.html



Source: Daewoo E&C Co., http://www.plantconst.com/lng/index.html

2.5 Materials for LNG storage Tanks

Selection of the proper materials of construction for cryogenic service is one of the most important considerations. Of primary concern is how the material will perform at cryogenic temperatures. Fracture mechanics involving such properties as notch toughness, ductility, critical flaw sizes, specific heat, coefficients of thermal expansion and thermal conductivity at cryogenic temperatures, as well as the usual strength and elastic properties of the material, must be studied. The cryogenic industry has long recognized the need to study the subject of fracture mechanics as it applies to materials of construction for cryogenic service.

Most metals increase in strength with a decrease in temperature. Copper, nickel, aluminum and most alloys of these metals exhibit no ductile to brittle transitions and, therefore, are suitable for cryogenic service. Stainless steel of the 18 per cent chrome, 8 per cent nickel classification also exhibits excellent ductility. The ASME Code, API Standard 620 and regulatory bodies in the construction of vessels for ultra-low temperatures have established certain minimum requirements.

Integrity of storage is obtained by the correct combination of:

- Selection of proper materials
- A suitable tank design
- Use of proven welding and inspection procedures
- Testing prior to placing structure in service

Materials for Cryogenic Tanks (Through -450°F)

Material	Designation Number	Pressure Storage (ASME)
Stainless	A240, Type 304	18,750
Aluminum	AA5052 AA5086 AA5083	6,250 8, 700 10, 000
5% Nickel 5% Nickel 9% Nickel	A 645 – A553 Class 1, A353	23,700 23,750

Table 2.1: Materials for Cryogenic Tanks, Source: Chicago Bridge & Iron Company (http://www.chicago-bridge.com/cbi/products/refrigerated_storage/refrigerated_storage_tanks.html)

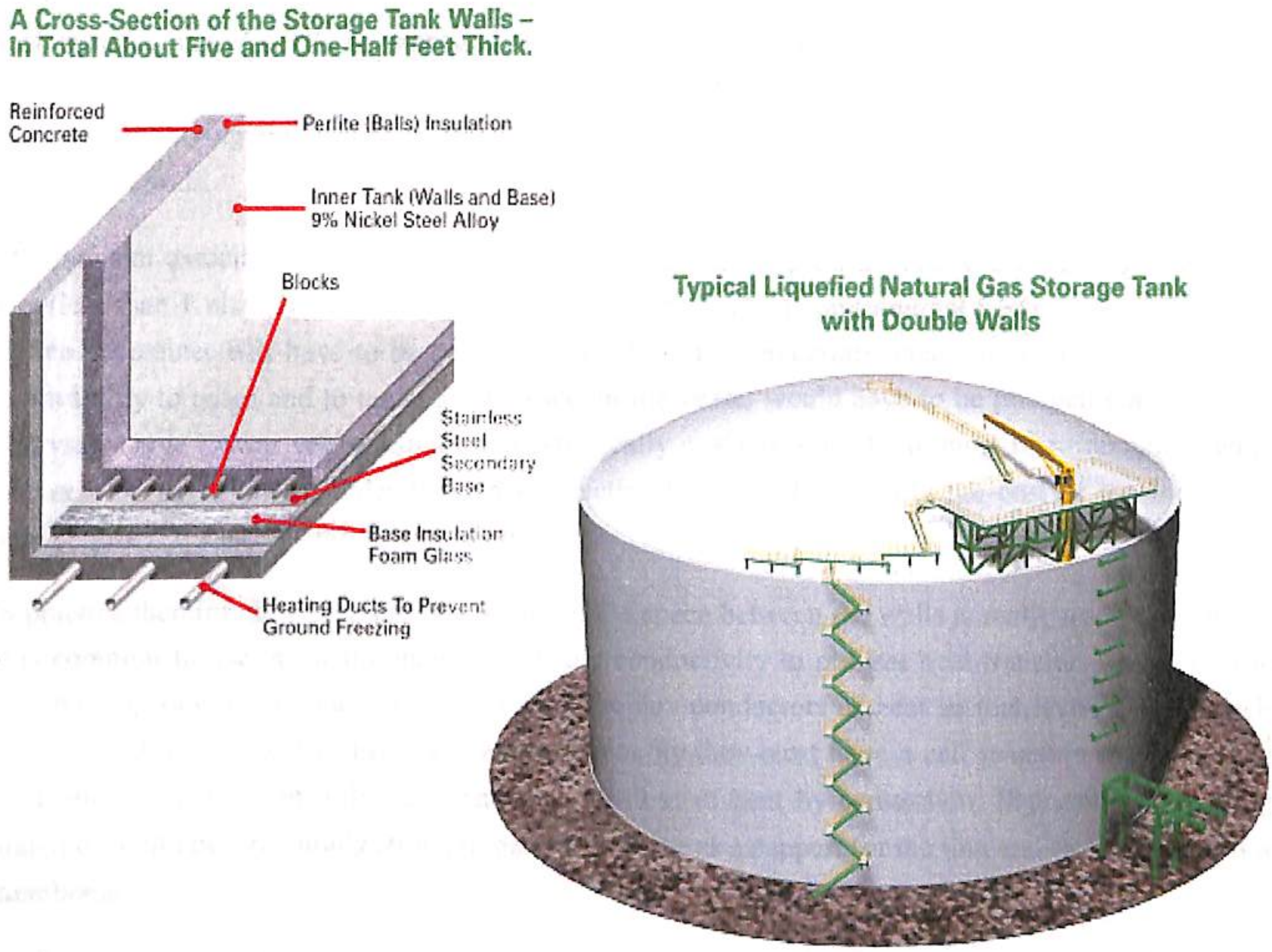


Figure 2.1: A typical LNG storage tank and the cross-sectional view of the LNG storage tank

Source: Beyond Petroleum (bp), LNG Storage tanks

2.6 Insulation of LNG Storage Tanks

Cryogenic storage tanks and their insulation systems must be designed to work together to assure optimum performance. Low temperature insulation is required for both spherical and flat bottom cylindrical cryogenic storage tanks. Heat transfer from the surrounding to a cryogenic fluid can takes place through triple mechanisms of conduction convection and radiation. The ideal means of limiting heat transfer, therefore, is to surround the cryogenic liquid with a vacuum through neither heat convection nor heat conduction can take place. If in addition, radiant heat transfer is minimized by providing reflecting surfaces their result a so-called Dewar vessel in which LNG can be stored for extended periods.

The problem associated with Dewar flask are several: vapour pressure inside the flask must be very low (less than 1 mm Hg) and to withstand external atmospheric and internal LNG pressure a double skinned container will have to be strongly built. Also most materials, including metals, have certain permeability to gases and to maintain the vacuum the vessel would have to be pumped out at regular intervals. Large Dewar vessel would be mechanically unstable since there must be minimum bracing between the two skins in order to limit conductive heat transfer. Finally the cost of the inner low temperature resistance membrane would be high.

In practice therefore low pressure or vacuum in the space between the walls is really used as such and it is common to use insulating materials of low conductivity to prevent heat transfer. Most of these materials operate in two ways. First they must be non-conductors of heat so that, even if they touch both walls, little convective heat loss occurs. Secondly they must have a cell structure to prevent the circulation of gas in the wall space and thus the loss of heat by convection. If possible, insulating material should be structurally strong to permit their use as a support for the thin and expensive interior membrane.

A further feature of low temperature insulation is the need to exclude moisture. While high temperature insulation will dry out under normal operating condition and thus gradually increased its ability to contain heat, low temperature insulation materials must be protect from the moisture which would deposit, built into frost or ice, and substantially weaken the heat barrier setup originally. The wall space of cryogenic tank if not under vacuum must, therefore, always be filled with dry gas.

In practice either liquid nitrogen vapour, which is of course absolutely water free, or vaporized LNG is circulated through the insulation space. If the letter is used there is no need to separate the insulating layers from the vapour space of the tank and LNG vapour can be allowed to spread into the insulation.

This has the additional advantage of equalizing pressure between tank content and insulation and permits a much lighter construction of the interior membrane of the storage tank.

Four types of insulating materials are used extensively in cryogenic systems. The cheapest and most common insulant is a power prepared by firing certain materials, e.g. silica, diatomite, magnesia or asbestos, which expand under the action of heat and of evaporating moisture; such materials are marketed under trade name such as Aerialite or perlite. Loose fill insulation is used to pack the wall space between the stainless steel membrane and the outer cylindrical walls of cryogenic tanks. When using it precautions must be taken against expansion/ contraction of the two vessels and slippage and empty space around the top of the cylinder. A further disadvantage of Perlite insulation is the need to empty the entire space before alteration can be made, instruments can be installed or repair effected. Power insulation is also unsuitable for use under tank bottoms where it is would be exposed to pressure and excessive consolidation.

The conductivity of loose fill insulation with dry gas filling the spaces between the powder particles is several times higher than that of vacuum jacketed (Dewar) vessels. A hybrid form of insulation, which combines some of the properties of vacuum jackets, i.e. low conductive transfer, and other properties of powder insulation, e.g. better support for the gas-impermeable membrane, is the evacuated powder filled jacket, frequently used for similar cryogenic vessel such as vehicle tanks.

The use of solid blocks of insulating material such as expanded polystyrene, PVC, phenol formaldehyde, foamed concrete, glass, rubber, balsa wood, etc. is essential if mechanical forced in addition to heat transfer are to be continued. While self supporting blocks of solid foam still have to be protected from water penetration by means of sealing materials such as bitumen, mastics, surface coatings resins and waxes they can be used on the outside of single skin vessel, and as floor support, particularly if protected by sheet metal or sheet PVC.

A third class of insulating material is fibrous in nature: glass wool, rock wool, slag wool and rock wool when attached to a rigid container can be used to take up thermal expansion and contraction owing to their inherent elasticity. They are also used an external tank roof insulation. Both performed blocks and blankets of fibrous insulation are useful in that alterations and instrumentation work are possible without removing the bulk of insulation. Both can be drilled through, the alteration made and the insulation patched around it.

The most recently introduced type of insulation is polyurethane foam produced *in situ* by forming a mixture of di-isocyanate, polyalcohol and water in the apace which it is proposed to fill. The reaction in a so-called ‘one shot’ system proceeds as follows:

Di-isocyanate + Polyalcohol⇒ Urethane

Di-isocyanate + Water ⇒Prim.Diamine+CO_2

Diamine + Urethane ⇒ cross linked Polyurethane

And since CO_2 is formed the resultant solid polyurethane has a foam structure. Sometimes the addition of a fluorocarbon (e.g. FCl_3C) is required to assist foaming. In other instance a prepolymer (reaction 1) is formed and introduced with the remaining ingredients. Careful control of foaming is essential, but routine insulation of shuttered walls or double skin containers is now well established. Polyurethane foams are non-absorbent since each cell is closed, and required only a modicum of waterproofing; they are also elastic and self supporting, thus combining the advantage of the previous two type. Apart from this application in a confined, shuttered space, polyurethane can also be sprayed onto open surface; however, this is difficult to do effectively in the open air and satisfactory polyurethane insulation has so far only been applied indoor by spraying.

Insulating materials, whatever type, i.e. loose fill, performed blocks, fibrous blankets or *in situ* foams must meet certain basic requirements. In particular their chemical and physical properties should not change extensively over their operating range; excessive embitterment at temperature around -160^0C would thus be unacceptable, just as melting and loss of insulation capacity at room temperature would be highly undesirable. While it is not absolutely necessary for the insulating material in an LNG plant to be fireproof, it is at least desirable that the insulant should retard flames and, particularly, that it should not collapse entirely during or after a fire. A residual carbon skeleton such as that left behind by burning cock, is useful, while fire resistance as provided by expanded perlite, magnesite or asbestos is ideal.

There are three principal types of shell and insulation systems for refrigerated gases: single steel wall (SW), double steel wall (DW), and concrete outer shell with double steel wall interior. Common to both the SW and DW insulation systems is the suspended deck roof insulation system. The following portions of this section describe DW, SW, suspended deck roof, and load bearing bottom insulation systems, and the concrete outer shell tanks in more detail.

2.6.1 Single Steel Wall Insulation System

The vessel wall in the SW insulation system is insulated with rigid polyurethane insulation foamed-in-place between the steel shell and an aluminum jacket. This design results in a monolithic insulation without cracks or voids fully bonded in a "sandwich" construction between the tank shell and the outer jacket.

The outer jacket serves as both the moisture vapor barrier and weather protection for the system. Products normally stored in tanks using the FIP insulation are those held at -60°F (-51°C) and warmer. The FIP single wall insulation system provides the following advantages compared to other single wall insulation systems using conventional block or layered systems:

- Insulation is bonded to both the aluminum vapor barrier and the steel tank shell. The many joints and voids associated with block systems are eliminated except in the area of the anchorage system where movement is required. This composite system minimizes spaces for channeled "breathing" of outside air.
- Integrally bonded system provides a composite structure with good resistance to severe weather.
- The aluminum weather protective sheeting provides an excellent vapor barrier for single wall insulation. The possibility of moisture migration into the insulation is minimized by the use of wide sheets with flexible sealant between the lapped seams. Available thickness of two to six inches (50 to 150 mm) reduce heat leak and thus reduce size, first costs and operating costs for holding refrigeration.
- Integrally bonded system is resistant to fire exposure. Fire retardant foam is used, and air is excluded from the bonded system thus preventing ignition prior to penetration of the outer jacket.

2.6.2 Double Steel Wall Insulation System

DW tank provides the best possible low temperature insulation. The system provides superior performance especially in the following potential problem areas:

- Wind and storms do not damage DW insulation systems. The outer steel tank is normally designed to withstand 100 miles (161 km) per hour winds and has withstood winds of hurricane force without damage.
- Steel plates with welded seams assure vapor barrier integrity. The annular insulation space is maintained under a slight positive purge pressure by use of a suitable dry gas.
- Repairs and work on the outer tank may be performed in the same way that work is done on conventional product storage tanks.

- ❖ Fire resistance of the DW system is excellent since the steel plate vapor barrier maintains almost full strength up to 650°F (343°C) and is still relatively strong during temperature excursions up to 1500°F (816°C). The perlite insulation used in DW systems is not structurally affected or damaged by temperatures up to 2000°F (1,093° C).
- ❖ "Insulation "K" Value" of the DW insulation remains constant once the loose-fill perlite in the sidewalls has been installed. The loose-fill perlite in the sidewalls and on the suspended insulation deck is fully protected from weather and humidity by welded steel plate.

Products normally stored in tanks with DW type insulation are those stored at -28°F (-33°C) and colder. Storage temperatures of -50°F (-46°C) and below often require DW insulation in order to satisfy owner's requirements for low heat leak, economical holding refrigeration, and low operating and maintenance costs.

Sidewall insulation is provided by perlite expanded and installed under slandered specifications. Perlite is an inorganic, nonflammable, lightweight insulation produced from special volcanic rocks. The volcanic rock or ore is finely ground and then expanded in furnaces operating at about 2100°F. The perlite is normally expanded in a field-operated furnace and placed in the insulation space while still hot. This method minimizes moisture in the insulation. It also minimizes breakdown of the perlite particles, since they are handled only once after expansion. The welded steel plate outer shell provides both containment and vapor protection for the perlite insulation. The insulation closure is a lap welded steel plate between the inner tank roof and the outer shell. The outer shell is entirely butt welded together and fillet welded to the outer steel bottom. The outer lap welded tank bottom furnishes a positive bottom seal for the shell insulation and a positive vapor barrier for the load-bearing bottom insulation.

A resilient blanket is wrapped around the inner tank shell to prevent pressure build up due to the perlite settlement that occurs if the perlite is not laterally supported when the vessel walls expand and contract. If this lateral support is not provided, the perlite will settle into the void left when the vessel walls contract and will be compressed due to excessive pressure when the walls expand. The outer vessel wall moves with changes in ambient temperature and the inner vessel moves with cool down and warm-up of the inner vessel. Also, filling and emptying the tank causes expansion and contraction of the inner tank wall due to elastic shell movements from hydraulically imposed stresses. Without the resilient blanket, this action can cause compaction of perlite that may damage the inner wall and attached fittings.

2.6.3 Suspended Deck Roof Insulation

Common to both the SW and DW insulation systems is the suspended deck roof insulation system. This system has been widely accepted because it provides permanent, inexpensive roof insulation. Externally applied insulation on curved roof surfaces is difficult to properly apply and has resulted in significant maintenance problems. These difficulties are completely eliminated by using the suspended insulation system.

The system consists of a lap-welded metal deck suspended from the tank roof framing. Perlite, mineral wool, glass fiber or other suitable insulation is distributed uniformly over the suspended deck. Open pipe vents are installed through the deck to equalize pressure above and below the deck. Super heated vapors remain stratified in the upper space between the deck and the outer roof, while colder nearly saturated product vapors are stratified below the suspended deck. The welded steel pressure containing tank roof provides positive, permanent weather protection for the suspended insulation. The insulating value of the suspended insulation will not change with age since there is no degradation or weathering of the insulation.

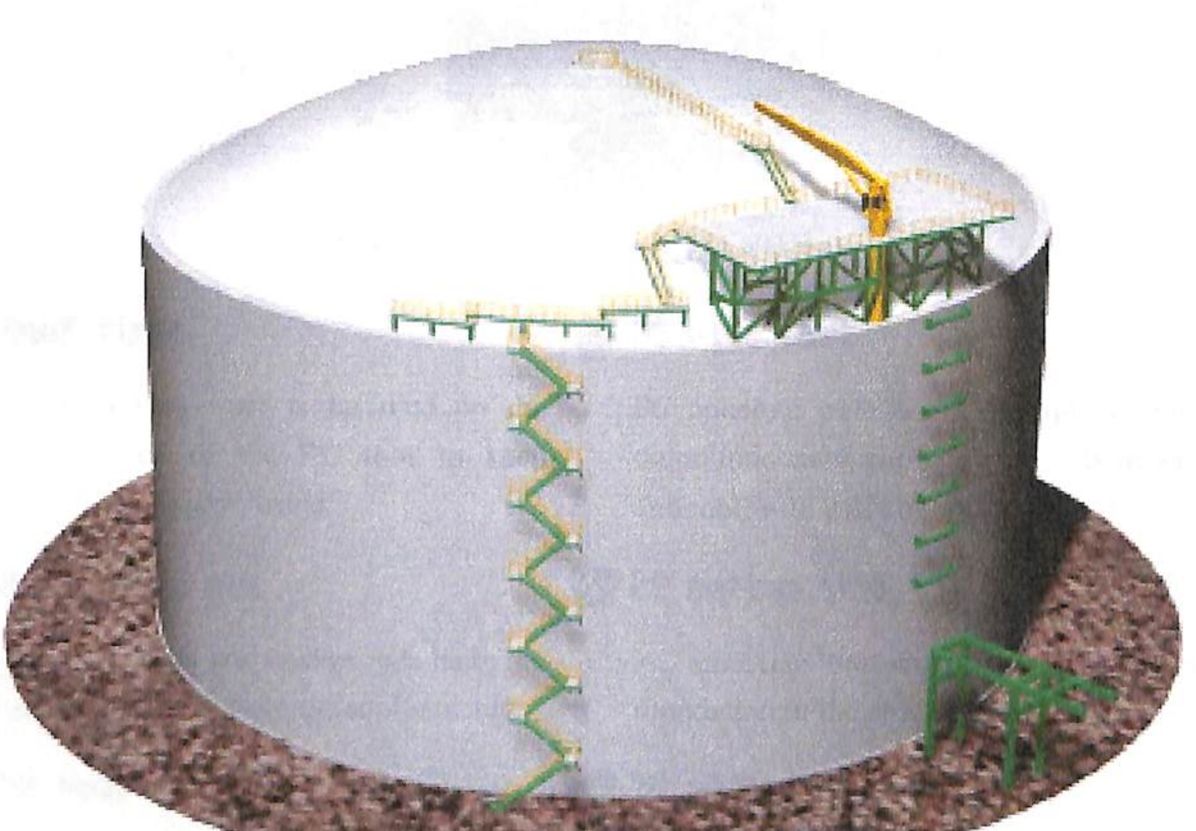
2.6.4 Load Bearing Insulation

All flat bottom cylindrical low temperature storage tanks require bottom insulation, which limits heat flux into the stored product and transmits the liquid load into the foundation. The details of the bottom, or load bearing insulation, are similar for both SW and DW insulation systems.

Two load bearing insulation systems are normally used. These are foamed glass and EPS Concrete; a lightweight concrete using expanded polystyrene beads as aggregate. For applications within the United States, foamed glass has most often been used. Outside the United States where packing and freight costs for shipping foamed glass is a significant cost factor, EPS Concrete is an economically attractive alternate. Unlike other lightweight concrete aggregates such as perlite and vermiculite, the polystyrene beads in EPS Concrete are closed cell and do not absorb water. EPS Concrete also maximizes the use of local materials and labor in the area where the tank is built. Alternative insulations are available, but they must each be reviewed for application on an individual basis.

Chapter- 3

Above ground LNG Storage tank



Chapter- 3

Above ground LNG Storage tank

Due to the cryogenic characteristics of LNG, a LNG storage tank has a double container, where the inner contains LNG and the outer contains insulation materials. Basically three tank design principles prevail: single containment tank, Double containment tank and full containment tank. The full containment tank is currently the prevalent type in the world. The detailed description of full containment LNG tank is as following.

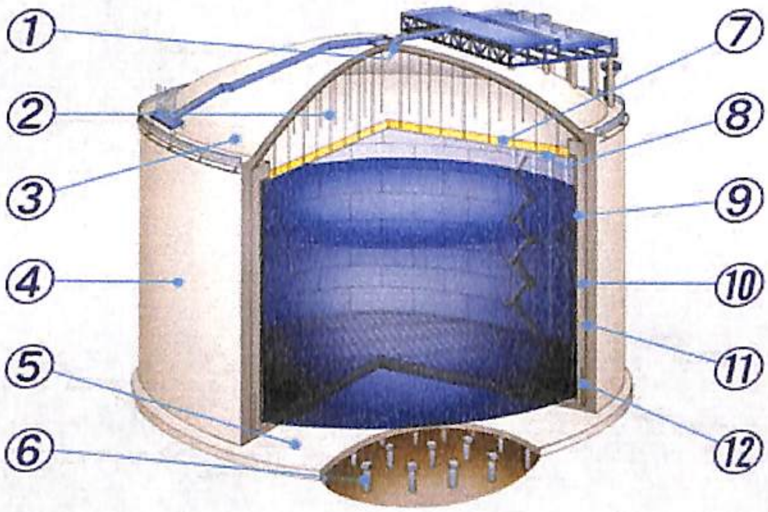


Figure 3.1: Full containment LNG tank

① Roof liner

A steel roof liner is installed on the inside face of the RC roof to keep natural gas vapor inside.

② Suspension rod

Stainless steel suspension rods hang the suspended deck from the roof structure.

③ RC roof

A concrete roof has the advantage of protection from heat from adjacent fires and from the impact of flying objects.

④ PC side wall

PC concrete wall is a LNG-tight design and monolithic connections are made between wall and roof, wall and bottom.

⑤ RC bottom slab

RC concrete bottom slab with piles is the foundation of the tank.

⑥ RC piles

Piles support the tank structure.

⑦ Roof insulation

Perlite powder or glass wool is used for roof insulation to maintain the inside temperature.

⑧ Suspended deck

Aluminum alloy suspended deck supports the roof insulation.

⑨ Inner shell

9%Ni steel inner tank is an open top structure and holds LNG in it.

⑩ Side insulation

Between the inner shell and outer sidewall is filled with perlite powder to make side insulation.

⑪ Side liner

A steel sideliner is installed on the inside face of the PC sidewall to keep natural gas vapor inside.

⑫ Secondary barrier

In the very rare case of inner tank leakage, LNG will accumulate inside of the 9%Ni steel secondary barrier.

Source: MITSUBISHI HEAVY INDUSTRIES, LTD. (http://www.mhi.co.jp/ydmw/e/tank/lng/ag/index.htm)

The construction costs of the tanks occupy the major portion of the LNG terminal's total construction costs. Therefore, various efforts have been made to increase the cost efficiency of the LNG tanks, which can be largely divided into two parts:

(1) There has been a clear tendency toward LNG tanks with higher capacity during the past decades. This can achieve a decrease in the relative cost per unit of stored capacity and enable a more effective land use. It also matches well with the increasing capacity of LNG ships.

(2) The cost efficiency as well as the shortening of the construction period have been pursued through the technological development in material and structural aspects.

As the capacity increases, special attention should be paid to the existing code provisions and the efficient procedure be established to design LNG tanks with structural and cost efficiency. Encouraged by the above-mentioned trend and with accumulated experiences of LNG tank construction for 15 years, Daewoo E&C has investigated the design procedure of above-ground prestressed concrete LNG tanks with 200,000 m^3 capacity. Some noteworthy points related to the large above-ground LNG tanks with concrete roof are reviewed in this article, focusing on the design aspects. The full description of above ground LNG Tank is given on the next page.

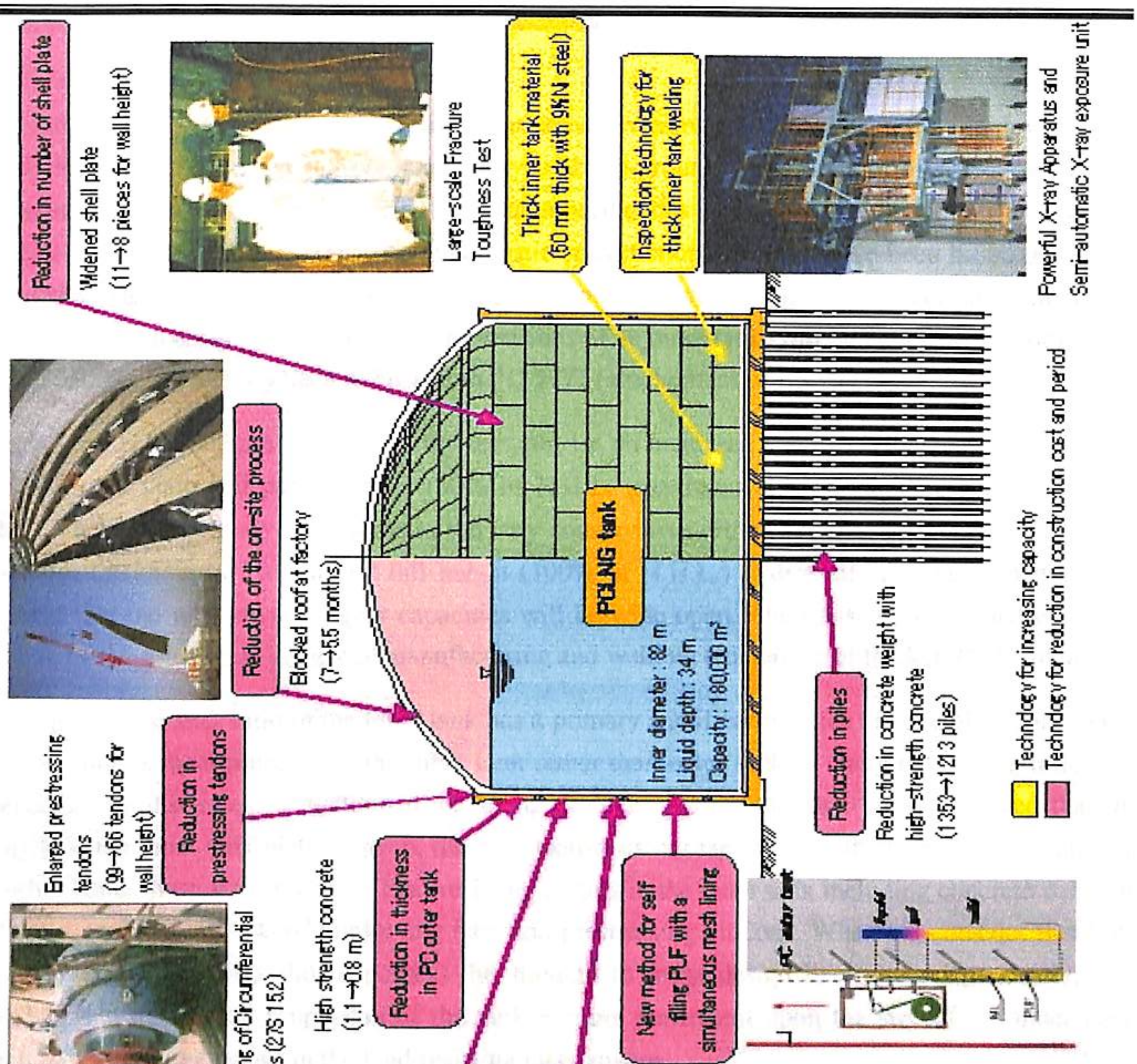


Figure 3.2: Full description of above ground LNG Tank
Source: OSAKA GAS CO. LTD. (http://www.osakagas.co.jp/rd/sheet/)

3.1 Design of 9% Ni Inner Tank

Recent documents have repeatedly reported that some revisions of the codes are required, especially for the inner tank, to design full containment type above-ground LNG tanks of higher capacity with economical proportions. The most commonly referenced codes for the design of inner tanks have been API 620 and BS 7777. Also, many of the domestic constructions in Japan have been based on Japan's own codes. However, the Euro code (EN 265002) now in preparation will reflect some important points required to design more reasonable dimensions of an inner tank with higher capacity; some parts of EN 265002 have already been published in PD 7777 (amendment of BS 7777).

Included in EN 265002 are two noteworthy features, i.e. an increased maximum thickness of 50 mm of the inner tank plate and partial height (60% of H.H.L. (maximum design liquid level)) hydrostatic testing. These substantially relax some of the very conservative provisions specified in BS 7777, i.e. a maximum thickness of 30 mm and full height (100% of H.H.L.) hydrostatic testing, by which it is expected that the way toward higher capacities will be wide open. The revised code actually reflects the state-of-the-art such as advanced manufacturing and welding techniques of thicker 9% Ni plates.

The height to diameter ratio of the inner tank has a primary significance since the overall proportion of the LNG tank is determined from the inner tank rather than outer tank in many cases. The following aspects can be discussed in relation to the sizing problem. As for the inner tank, provided that the strength of the inner tank plate is given, the only load-resisting factor is the thickness of the plate. On the other hand, there are some more load-resisting factors in the outer tank including concrete strength, thickness, and the amounts of reinforcing bars and prestressing tendons. When we consider that both the inner and outer tanks should possess the strength to resist design loadings independently, it is plausible that the overall proportion of the tank is more dependent upon the size of the inner tank, which has less redundancies in the load-resisting mechanisms.

Thus, it is recommended that in a preliminary design stage several alternatives of the inner tank dimensions (height, diameter, thickness, etc.) be compared together to select a candidate that minimizes the material cost of the outer tank as well as the inner tank.

3.2 Roof Dome

Many of the existing concrete roof domes of above-ground LNG tanks have a radius of curvature equal to d (diameter of outer wall). It corresponds to a rise to diameter ratio of 1/8, which is often recommended as an efficient structural shape for the roof domes where self-weight or externally distributed load is dominant.

On the other hand, a higher rise is advantageous when the roof is subjected to internal pressure, which is one of the main design loadings in LNG tanks, since the higher curvature can endure the internal pressure with less tensile stresses.

Therefore, it can be mentioned that the conventional rise of the above-ground LNG tank domes is not optimal, at least from the structural aspects. When designing large LNG tanks with increased dome span, it is recommended that several alternatives of the dome dimensions (radius of curvature, thickness, etc.) are compared to determine the structurally safe yet efficient shape with a minimum amount of concrete.

No special code-related restriction is imposed on the shape of the concrete dome; however the codes for the carbon steel liner that is attached inside the concrete dome should be followed also. For example, API 650 specifies that the radius of curvature of the liner should range from 0.8d to 1.2d. Some of the large in-ground LNG tanks where the roof dome is also exposed above the ground level have the radius of curvature close to 0.8d. Buckling safety of the carbon steel liner is also important and varies sensitively depending on the shape and placing method of the concrete dome.

3.3 Ring Beam

The ring beam is located at the upper end of the wall. The primary role of the ring beam is to cope with the major portion of the thrust transmitted from the roof dome, thus reducing excessive deformation of the upper part of the wall as well as the roof dome. Therefore, the dimensions of the ring beam and the amount of prestressing tendons inside the ring beam have a close relationship with the shape of the roof dome. From the geometrical consideration, a higher rise dome induces less thrust to the ring beam, and is therefore advantageous for the ring beam as well as the dome itself.

The construction sequence of roof dome placing and ring beam prestressing has a primary importance because the stress state of the ring beam is much affected, depending on the sequence. The procedure should be so planned as to avoid excessive compression or tension in the ring beam throughout all the phases.

3.4 Outer Wall

The safety and serviceability of the outer wall should be checked in various modes of operation: (1) The construction stage, (2) Normal operation, (3) LNG leakage from the inner tank. It may be an important design issue to maintain a slender wall thickness and proportion when a tank size gets bigger with the wall height increased. To achieve this purpose, it is expected that the conventional design practice should be revisited and improvements be made as necessary. Some of the possible improvements are introduced here.

High strength concrete contributes to raising the section strength often resulting in a thinner section. As an example, a high strength of 600 kgf/cm^2 over conventional 400 kgf/cm^2 has been adopted for the wall of an LNG tank in Senboku, Japan. It is reported that the wall thickness was actually reduced by 30 cm by the strength increase.

Prestressing is a main design load in the construction stage, where the section is often subjected to a more critical stress state in the construction stage than the operation stage. During the prestressing sequence of horizontal hoop tendons, a large amount of section force (moment) and corresponding tensile stress is produced at the lower part of the wall from restraint of the wall deformation by the rigid bottom slab. When the wall becomes higher with increased capacity, the hoop tendons become too congested in the lower part of the wall according to the conventional design practice of tendons (Figure 3.2). This would produce excessive or sometimes unallowable stresses at the joint of wall and bottom slab in the construction stage.

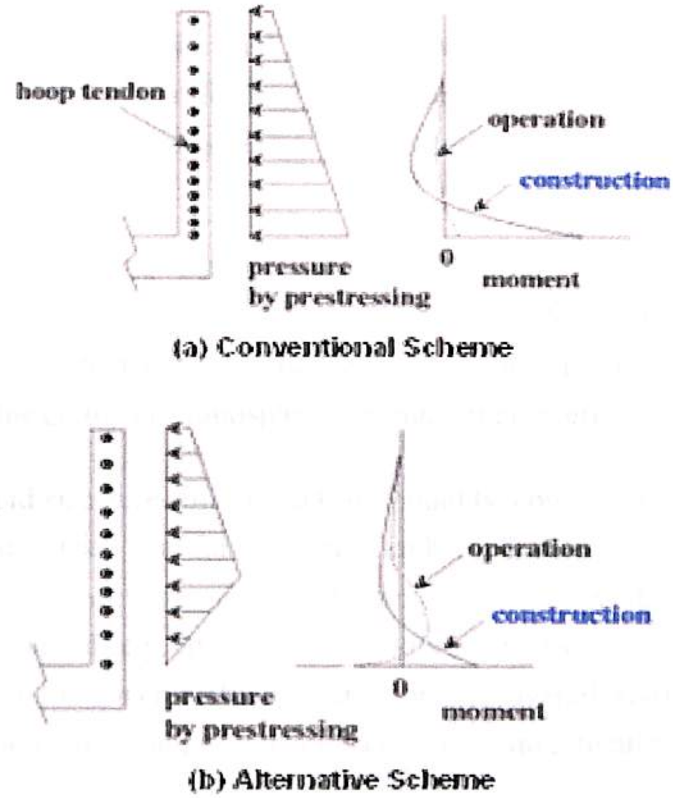


Figure3.3: conventional and alternative prestressing schemes

Source: LNG journal Published in the March/April 2004 LNG Journal

One straightforward countermeasure to reduce the stress is to increase the thickness in the lower part of the wall. Other than the thickness increase, one conceivable and powerful alternative is to revise the hoop tendon arrangement. According to recent researches, it is effective to modify the conventional tendon-induced trapezoidal pressure distribution into other types of distribution, an example of which is shown in Figure 1(b). This strategy can be achieved by adjusting the spacing of the hoop tendons in the lower part of the wall through some trial and error or optimization technique. The advanced pressure distribution produces moderate magnitude of the base moment during the construction stage as well as the normal operation. Of course, the required number of tendons can be reduced as an additional advantage.

3.5 Advanced Structural Analysis

During the past decades, computer-based structural analysis tools such as FEM (Finite Element Method) have achieved such great progress that the structural behavior can be estimated with high accuracy nowadays. It should be remembered that accurate and realistic structural analysis is always a key factor to design an LNG tank with optimized sections no matter what capacity it has. There are various structural analyses involved in the design of a LNG tank, some of which require more intensive and advanced techniques. Among them are heat transfer analysis of a structure subjected to the cryogenic temperature of LNG internal or external fire analysis, and seismic analysis of the structure containing the fluid.

In the temperature-related analyses attention should be paid to establishing proper boundary conditions, since a LNG tank has complicated structural details inside including a suspended deck and various insulation layers. Especially, the favorable effect of the suspended deck, which isolates the inner surface of the roof from direct exposure to the cryogenic atmosphere, should not be overlooked.

In a detailed seismic analysis of an LNG tank, fluid-structure-soil-interaction should be considered. BS 7777 specifies that dynamic analysis should be carried out for the outer tank of double and full containment systems for areas with high seismicity. However, combined dynamic analysis considering the inner and outer tank as a whole could be required, e.g. at the client's request. In that case, the dynamic effect of the insulation layers between the inner and outer tank on the overall seismic behavior of the LNG tank makes the actual situation more complicated and needs more investigation.

3.6 Technologies for reduction in construction cost and period

3.6.1 High-strength, self-compacting concrete

High-strength concrete as 60 N/mm^2, 1.5 times stronger than conventional concrete was adopted for the prestressed concrete outer tank wall material, which helped to reduce wall thickness by about 30%. The high powder content of the concrete enables to employ self-compacting concrete. Accordingly reduction of concrete placing times by means of heightening of concrete placing lot derived shortening work period. And labor saving conducted elimination of workers for compacting concrete. Design requirements for PC outer tank concrete include self-compactibility, as well as high-strength and liquid tightness after hardening, and life-long durability. Accordingly, materials and admixtures were developed along with production, quality control and installation technologies for concrete placement.

3.6.2 Enlarged shell plates

Expanding width of each inner shell plate from 3.2 meter to 4.3 meter and thus reducing shell plate courses from 11 courses to 8 courses have achieved the decrease in welding work on the inner tank. In employing large size 9% Ni steel plates, it was confirmed that the uniformity was maintained throughout the plate in the material performance and dimensional accuracy.

3.6.3 Self-elevator scaffold

The outer tank is divided into circular segments and constructed stage by stage in a vertical direction. The conventional construction method needs large crawler cranes to elevate the large scaffold and formwork divided into 36 segments. In the new construction method, adoption of hydraulic jacks for the elevation can elevate the entire scaffold and formwork simultaneously. This method enables to shorten the construction period.

3.6.4 Quality control and assurance system for concrete using Information Technology

Monitoring of manufacturing data such as records of individual material weight, surface water ratio of aggregates and mixer load value is indispensable because self-compactability of the concrete depends on the during mixing condition. This system enables to collect the manufacturing information in real time by using internet, self-compactability of the concrete can be adjusted surely and promptly.

3.6.5 Method for self-filling Poly-urethane form (PUF) with a simultaneous mesh lining

New method for self-filling PUF with a simultaneous mesh lining is adopted for construction of cold resistance relief inside PC outer tank. In conventional method, after the sprayed PUF was shaved and formed, mesh lining was pasted up. In this method, the construction of PUF and mesh lining are conducted simultaneously by winding off the rolled mesh lining from bottom of the LNG tank and injecting PUF between mesh lining and outer tank. In addition to cutting cost and shortening the work period, reduction of hazardous job on the gondolas in the high and narrow space such as height of 40 m and width of 1.1 m. And improvement of execrable working condition in the airborne dust, and reduction of most waste are achieved.

3.6.6 Roof structures constructed to the blocks

By the completing the knuckle-plates or roof frames and plates, which were conventionally carried in with the single article, to the blocks at shop, large shortening of the on-site process has been acquired.

Chapter- 4

Under Ground LNG Storage Tank

Chapter- 4

Under Ground LNG Storage Tank

The main body of a LNG in-ground tank is buried in the ground. This in-ground tank is composed of concrete wall and base sealed by stainless steel membrane. Mainly two types of in-ground LNG storage tanks are used in around the world, different in roof shape, the suspension deck type and roof inner insulation type (without suspended deck). In-ground storage tanks have a high level of safety and are environmentally friendly.

4.1 The Suspension Deck Type

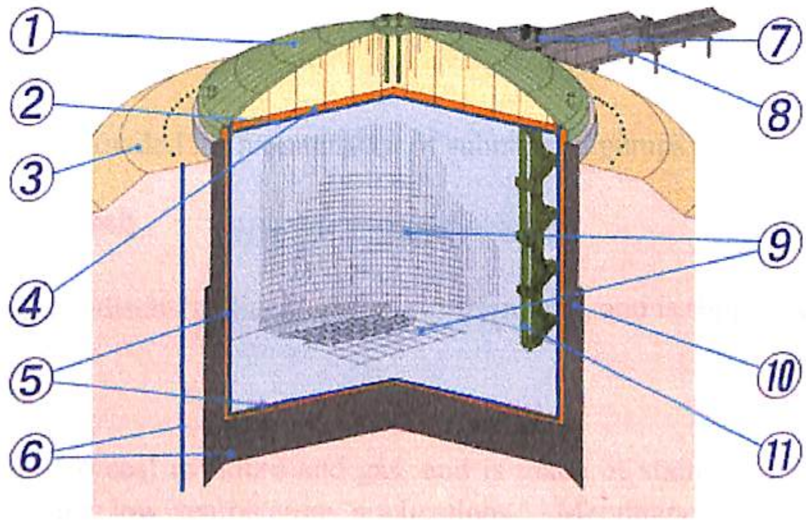


Figure 4.1: The Suspension Deck Type LNG storage tank

① Domed roof

The roof is provided to hold gas in the tank and accommodates all nozzles, openings and pump barrels. The roof structure is composed of rafters, rings and roof plates, and is supported on the top of the wall. In some cases the roof is covered by concrete to protect the steel surface.

② Suspension deck

The suspension deck of aluminum-alloy is hung from the roof structure and has the function to support the insulation material on the suspension deck. The level of the suspension deck is designed with consideration of sloshing wave height that may occur from earthquakes.

③ Berm

The berm is provided around the tank for increased safety.

④ Insulation on suspension deck

Glass wool, which is lightweight and has high insulation characteristics, is used.

⑤ Side and bottom insulation

To support membrane side and bottom, insulation materials are rigid polyurethane foam (PUF) that has superior pressure resistance and insulation capabilities and is fabricated in panel shapes at the factory. Pressure resistance is taken into consideration for the selection of the material.

⑥ Heater

Bottom and side heating pipes are provided to prevent frost heave.

⑦ Pump stage

The pump stage is provided for maintenance of submerged pumps.

⑧ Piping and sub-rack

Piping is to feed and discharge liquid and gas to/from tank, and is supported by sub-rack.

⑨ Membrane

The membrane is to seal in liquid and gas, and is made of stainless steel (SUS304) that has extensive usage for low temperature applications. Membrane system is installed on the insulation panel and the pressure of liquid and gas is transferred to the tank via the insulation layer, insuring the operation is stable and safe. The membrane is of a single corrugation type. Corrugations are formed by being bent in corrugation shape and arranged lengthwise and crosswise to absorb thermal contraction in any direction.

⑩ Side wall and base

The sidewall and base are made of reinforced concrete to withstand forces such as gas and liquid pressure, soil pressure, water pressure, earthquakes and other loads. The structure and its construction method are determined by soil and other conditions.

⑪ Pump barrel framing

Discharge pump barrel and feed pipe have openings at the bottom of tank and are supported by the roof. Usually swing protection is installed in the bottom enabling it to slide upward and downward. An inner stair made of stainless steel is provided with the pump barrel for construction purpose.

Source: MITSUBISHI HEAVY INDUSTRIES, LTD. (http://www.mhi.co.jp/ydmw/e/tank/lng/ag/index.htm)

4.2 The Roof Inner Insulation Type (Without Suspended Deck)

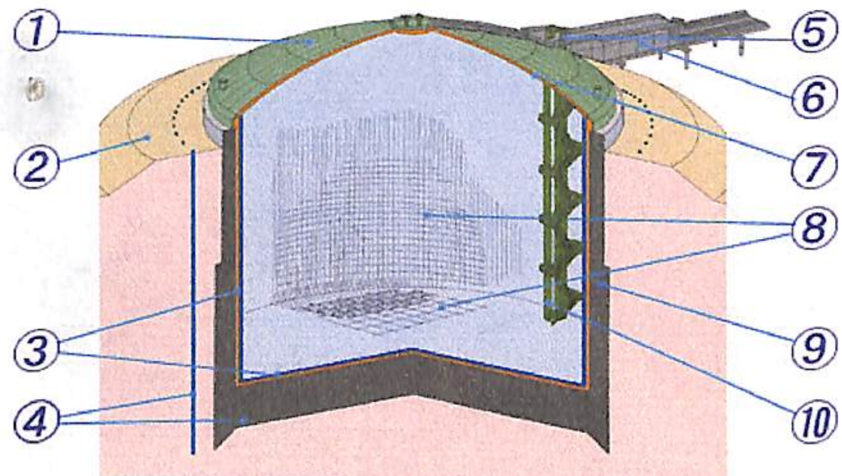


Figure 4.2: The Roof Inner Insulation Type (Without Suspended Deck)

① Domed roof

The roof is provided to hold gas in the tank and accommodates all nozzles, openings and pump barrels. The roof structure is composed of rafters, rings and roof plates, and is supported on the top of the wall in some cases the roof is covered by concrete to protect the steel surface.

② Berm

The berm is provided around the tank for increased safety.

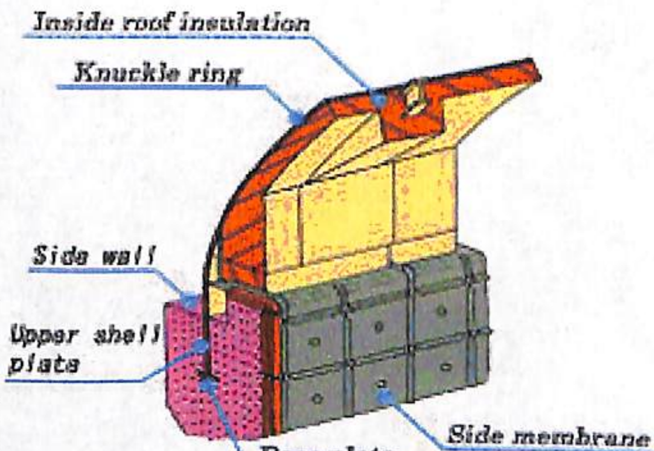


Figure 4.3: Roof inner insulation type structure of ruff and side wall

③ Side and bottom insulation

To support membrane side and bottom insulation materials are rigid polyurethane foam (PUF) that has superior pressure resistance and insulation capabilities and is fabricated in panel shapes at the factory. Pressure resistance is taken into consideration for the selection of the material.

④ Heater

Bottom and side heating pipes are provided to prevent frost heave.

⑤ Pump stage

The pump stage is provided for maintenance of submerged pumps.

⑥ Piping and sub-rack

Pinging is to feed and discharge liquid and gas to/from tank, and is supported by sub-rack.

⑦ Roof insulation

To protect from sloshing in case of earthquake, inside of the steel roof is covered by rigid polyurethane foam (PUF) that has superior pressure resistance and is fabricated in panel shapes instead of insulation on the suspended deck.

⑧ Membrane

The membrane is to seal in liquid and gas and is made of stainless steel (SUS304) that has extensive usage for low temperature applications. The membrane system is installed on the insulation panel and the pressure of liquid and gas is transferred to the tank via the insulation layer, insuring the operation is stable and safe. The membrane is of a single corrugation type. Corrugations are formed by being bent in corrugation shape and arranged lengthwise and crosswise to absorb thermal contraction in any direction.

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Discharge pump barrel and feed pipe have openings at the bottom of tank and are supported by the roof. Usually swing protection is installed in the bottom enabling it to slide upward and downward. An inner stair made of stainless steel is provided with the pump barrel for construction purpose.

Source: MITSUBISHI HEAVY INDUSTRIES, LTD. (http://www.mhi.co.jp/ydmw/e/tank/lng/ag/index.htm)

4.3 How in-ground LNG storage tanks work

The sidewall and bottom slab of in-ground storage tanks have a multiplex structure with three layers: (1) reinforced concrete, (2) insulation and (3) a membrane. Since the sidewall and bottom slab of in-ground storage tanks are subjected to external earth and water pressure more than internal pressure, reinforced concrete is an ideal material because of its excellent compressive strength. The tanks are specially designed to withstand earthquakes underlining their high level of safety.

Rigid polyurethane foam (PUF) insulation restricts the permeation of heat from outside and transfers the internal gas and LNG pressure exerted on the tank side wall and bottom slab.

A two-millimeter membrane layer maintains LNG and gas tightness. The membrane is corrugated to absorb contraction due to the difference in ambient temperature and LNG temperature, which is minus 162 degrees Celsius.

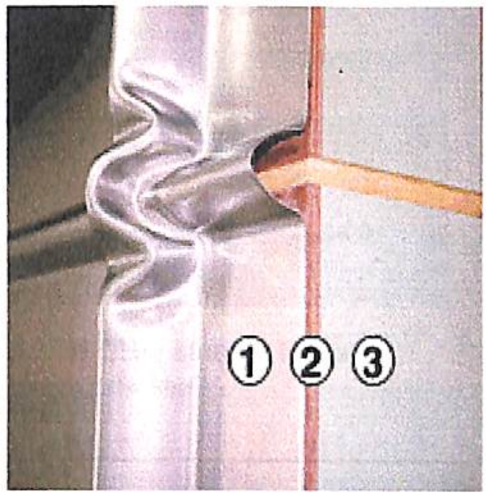


Figure 4.4: The sidewall and bottom slab of in-ground storage tanks
Source: Tokyo Gas Co., Ltd.
(http://www.tokyo-gas.co.jp/techno/)

4.4 Features of in-ground storage tank:

4.4.1 Safety

In-ground LNG storage tanks are only partially visible from the outside of the terminal site making them difficult to be targeted by terrorists. Furthermore, since the LNG is stored below the ground surface, in the unlikely event of a terrorist attack or the concrete roof being destroyed by a projectile, the LNG would not leak onto the ground. Accordingly, the tanks are accredited with the European standard EN1473, making them the safest way to store LNG. In an earthquake the seismic motion is not amplified for in-ground storage tanks when compared to above-ground structures making them safer in earthquake-prone regions. In order to make the tanks much safer from terrorist attacks, tank roofs can be lined with reinforced concrete or the roof of the tanks can be completely underground.

4.4.2 Environmentally friendly

The roofs of in-ground LNG storage tanks are the only part visible from the surface making the tanks a difficult target for terrorists. Moreover the tanks are not obtrusive to the surrounding environment, reducing the psychological impact that large tanks usually arouse.

Figure 4.5 Isometric view of in ground and under ground LNG storage tanks
Source: Tokyo Gas Co., Ltd. (http://www.tokyo-gas.co.jp/techno/)

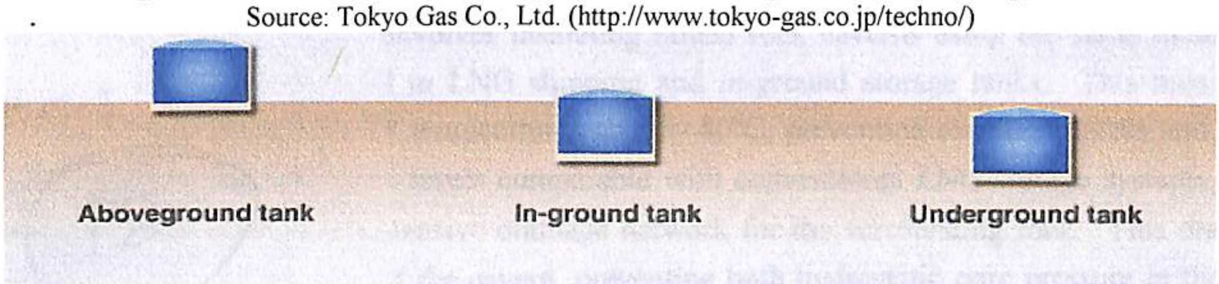


Figure 4.6: sectional view of in ground and under ground LNG storage tanks
Source: Tokyo Gas Co., Ltd. (http://www.tokyo-gas.co.jp/techno/)

4.4.3 Space-saving

In-ground storage tanks do not need to be surrounded by a dike and the legally required space between tanks as well as the necessary distance from items to be protected is relatively small allowing the tanks to conserve space.

4.5 Construction costs and time

It is now possible to construct large capacity in-ground storage tanks thanks to advances in technological development. Currently, Tokyo Gas constructs in-ground storage tanks sized from several thousand cubic meters to 200,000 cubic meters. Larger storage capacity makes for a lower per-unit cost. In-ground storage tanks are constructed at roughly the same cost as conventional above-ground storage tanks adding to the economical benefits. Construction time is also relatively the same for in-ground storage tanks.

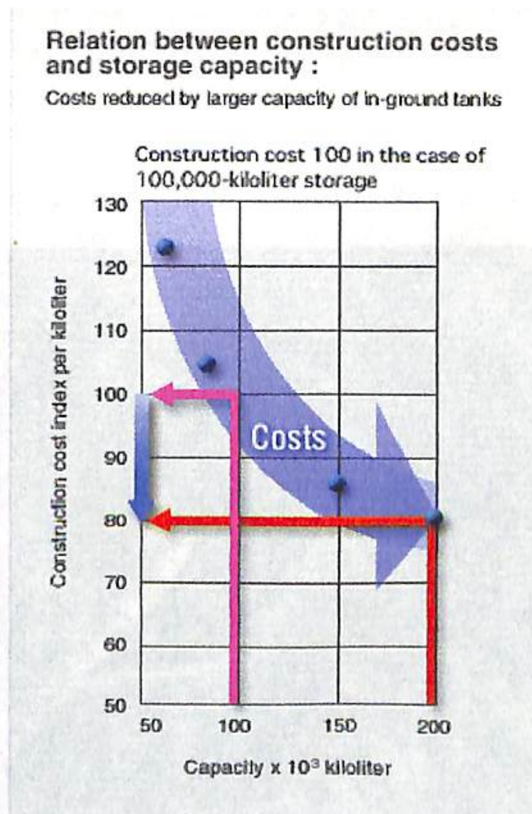


Figure 4.7: Construction costs and time
Source: Tokyo Gas Co., Ltd.
(http://www.tokyo-gas.co.jp/techno/)

4.6 Rock Cavern Storage

As the most expensive and conspicuous element in import terminals, LNG storage continues to inspire innovative new solutions. The most recent alternative to convention tanks to be proposed is storage in lined rock caverns.

The lined cavern storage system involves insulating mined rock caverns using the same membrane storage technology currently used in LNG shipping and in-ground storage tanks. This membrane system keeps the surrounding rock temperatures above -80^0C, preventing excessive stress and crack formation and reducing boil-off to levels comparable with conventional LNG storage systems. The cavern system also requires an extensive drainage network for the surrounding rock. This drainage system removes water from around the cavern, preventing both hydrostatic pore pressure in the rock structure and ice formation behind the cavern lining. Once the surrounding rock is sufficiently cooled, drainage is discontinued and water is allowed to seep back into the rock and form an impervious ring of ice around the caverns. This ice ring acts as an additional containment barrier for the stored LNG, further reducing opportunities for gas or liquid leakage.

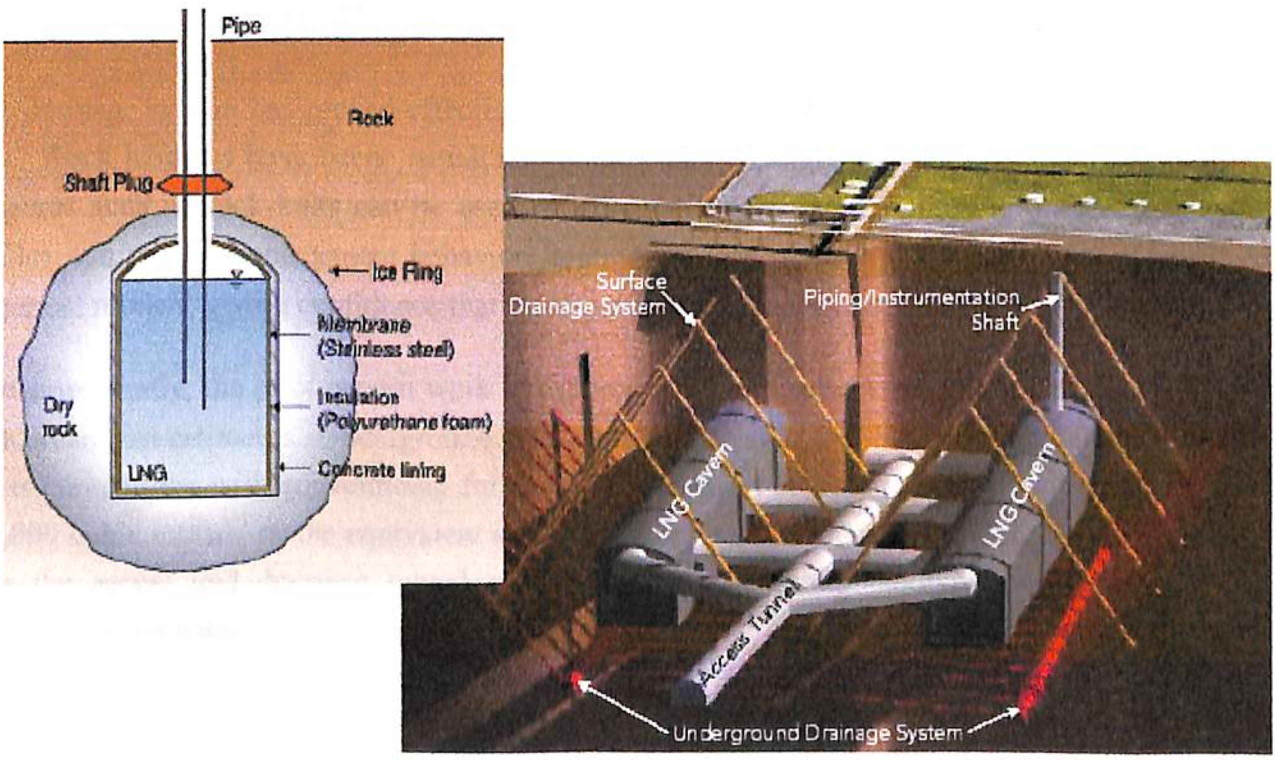


Figure 4.8: LNG storage in lined rock caverns - conceptual design
Source: Poten & Partners monthly publication LNG in world market- Octber-2004

Underground storage seems most appropriate for countries that have strategic gas storage needs. High construction costs those countries make cavern technology competitive with conventional systems. In addition, underground caverns can be built underneath the LNG terminal facility, reducing land requirements and making the terminal less conspicuous than a conventional complex - both favorable characteristics in densely- populated areas with limited real estate and vast storage requirements.

Construction timelines also appear competitive. Preparing an underground cavern requires four mining and drilling stages. First, a sloped tunnel is excavated from the surface to about 50 meters below grade, providing access for personnel, machinery, spoil removal and ventilation. At the same time, a surface drainage system is drilled and drainage is established to minimize water ingress during construction. The storage caverns are then mined from the rock structure, before the underground part of the drainage system is excavated and drainage completed to desaturate the surrounding rock.

Following the mining stages, the cavern's rock surfaces are lined with a reinforced concrete shell, then an insulation layer and finally the stainless steel membrane liner. Once in operation, column-mounted in-tank send out pumps send LNG to the above-ground recon denser, high-pressure send out and vaporization systems, in the same way as conventional regasification terminals. Piping and instrumentation for each cavern enters through a single mined shaft in the cavern roof.

The drainage system has proved effective, establishing stable, low pore pressures in the surrounding rock. Rock loadings have been small and predictable; meaning conventional cavern reinforcement measures such as rock bolts can be used on cryogenic caverns. Finally, the observed temperature profiles and rock displacement behaviors around the cavern closely resembled those predicted by numerical models, giving confidence that these models can be applied to future full-scale designs.

Most importantly, the pilot cavern work has increased confidence in the full-scale designs as well as the Korean cost estimates. Underground cavern storage appears less expensive than in-ground storage, and is competitive with conventional full-containment tanks at higher storage facility volumes above 300,000 cubic meters, or the equivalent of two conventional storage tanks. Economies of scale come from the access and drainage tunnel systems, which need minimal expansion as storage cavern requirements increase.

4.7 Salt Cavern Storage

The research project, which is led by Conversion Gas Imports (CGI) and co-sponsored by Washington's Department of Energy and several energy companies, has developed a core terminal design based on CGI's Bishop Process for unloading and vaporizing LNG directly into underground salt caverns. The Bishop Process' most significant departure from conventional terminal design involves replacing cryogenic LNG storage tanks - typically the most expensive element in a receiving facility - with high-pressure gas storage in underground salt caverns. Salt cavern storage is considered less expensive than cryogenic liquid tanks, particularly at higher volumes, and increases the terminal's peak gas send out capabilities.

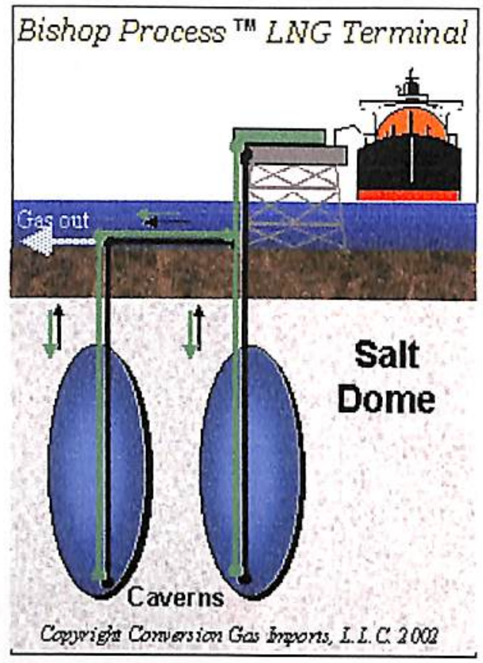


Figure 4.9: Bishop Process LNG Terminal
Source: http://www.conversiongas.com/index.html

Cavern capacities and characteristics can be specifically designed for each application. Drilling a hole to the planned depth, and then pumping fresh water or seawater through the space to gradually dissolve the required cavity volume out of the salt structure form each cavern. With proper control, each cavern can be leached out to its design diameter and height within a year. By contrast, building an LNG storage tank takes about three years. CGI's design envisages four to seven caverns at each "mega-terminal" facility, depending on ship size considerations, base-load gas send out and required operational flexibility. Once in operation, storage capacity can be expanded inexpensively, as leaching additional cavern volume is a small portion of overall development costs.

Storing imported natural gas as a dense phase gas rather than a cryogenic liquid does, however, significantly increase the terminal's high-pressure pumping and vaporization loads. Unlike a conventional terminal, the Bishop Process immediately vaporizes the LNG at the point of ship discharge rather than when the gas is sent out from storage. For a 10,000 m3/hr unloading rate, this increases the terminal's vaporization capacity to around 5 Bcf/d between two and 10 times the typical terminal design load. However, these higher pumping and vaporization loads dramatically increase the facility's peak power demand: about 65 MW of offshore power generation capacity is required adjacent to the ship unloading position.

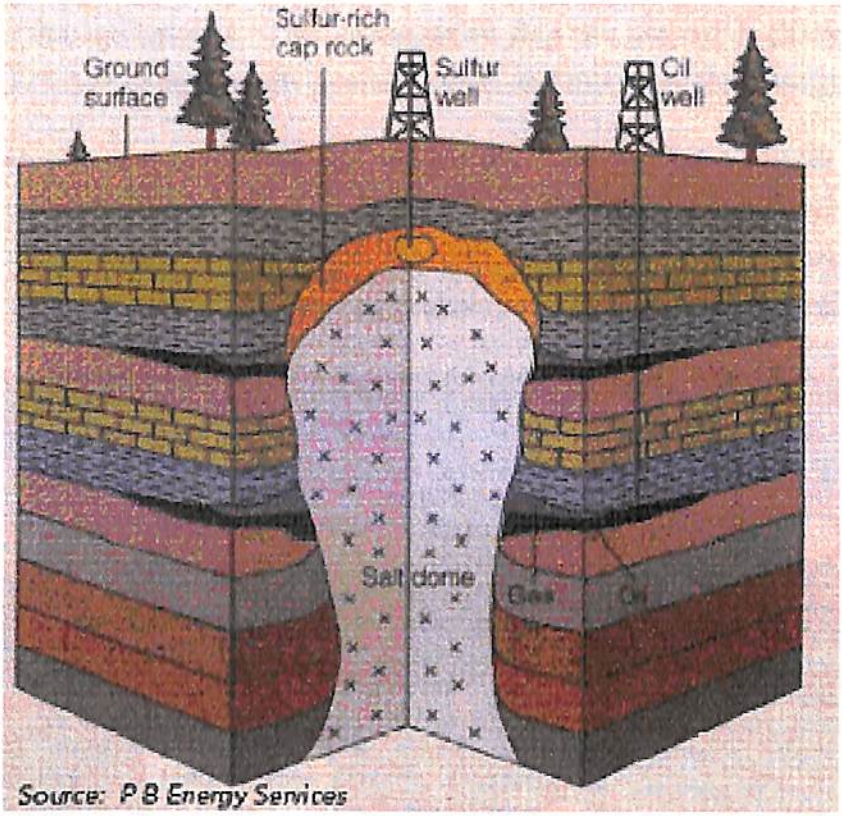


Figure 4.10: Atypical Salt Dome Profile

To ensure high terminal availability and reduce offshore construction costs, the CGI concept proposes using a floating weather-vaning unloading platform. Four different vendors have submitted platform designs so far. These comprise Blue water Offshore, FMC SOFEC, Remora Technology and SBM Imodco. The four designs vary in their water depth requirements and their support platform needs, with some designs requiring an additional platform for the pumps and vaporizers. However, all the designs weather vane to allow for changes in offshore wind and sea current conditions during ship mooring and unloading. Floating designs should also help reduce wave interaction "coupling" problems created by close proximity between the ship and a stationary platform. In addition, each design allows unloading though a conventional ship's manifold. The discharged LNG is pumped directly to either pipeline pressure (nominally 1,00 psig) to meet the onshore demand, or to the salt cavern storage pressure (between 900 and 2,000 psig, depending on how full the caverns are during unloading). Although this requires both higher flow rates and higher pressures than typically required for LNG sendout pumps, proven high-pressure multi-stage cryogenic pumps are available from multiple vendors for this service.

The dense-phase high-pressure LNG flow is then warmed to above 40°F before entering either the send out pipelines or storage caverns. This vaporization step can use either CGI's proprietary Bishop Process Exchanger (BPE) or commercially available shell and tube vaporizer designs.

The BPE is a simple pipe-in-pipe design that warms the LNG against seawater in a bank of long, parallel rack-mounted exchangers. Full-scale field-tests on the BPE during April at AGL Resources' peak-shaving plant near Canton, Georgia generally met or exceeded performance expectations, with the exchanger's low levels of ice formation being probably the most noteworthy outcome.

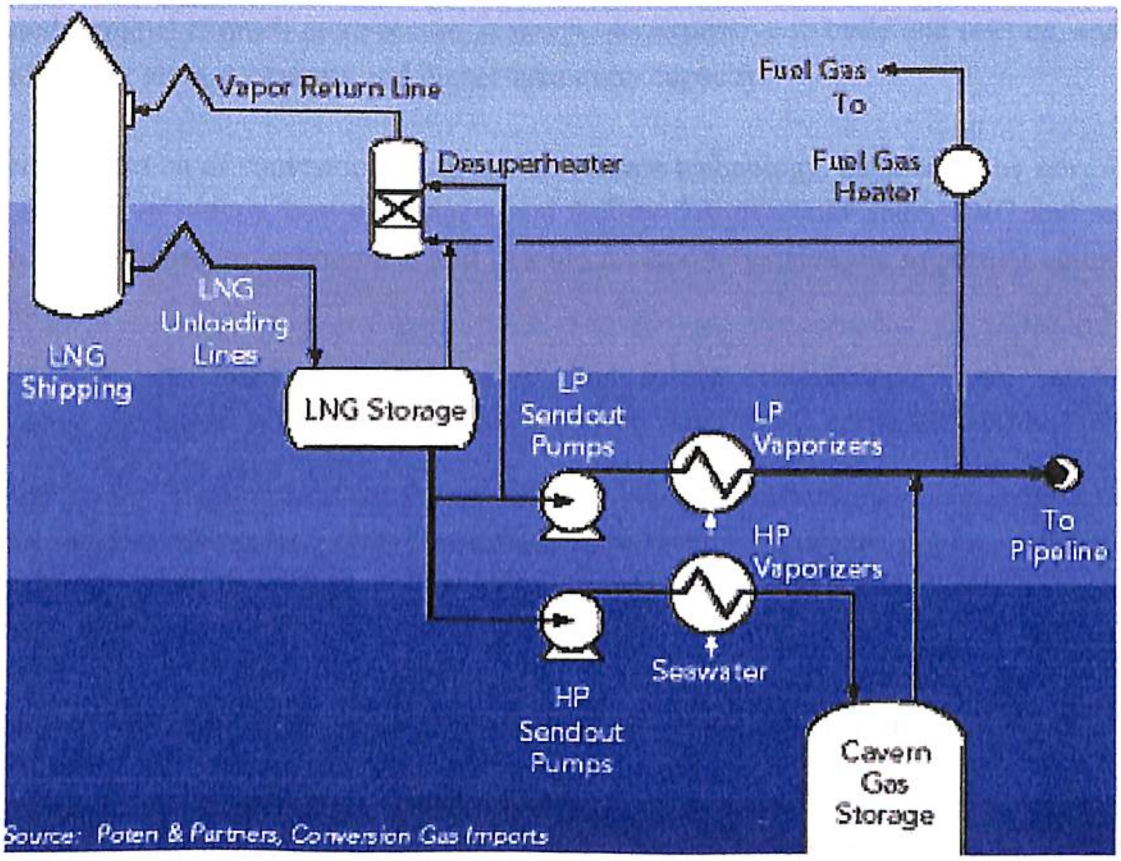


Figure 4.11: A Typical Bishop LNG Receiving Terminal

Gas withdrawals from salt cavern storage are expected to use "non-compensated" operation, where only the differential pressure between the storage cavern and the sendout pipeline can be used to withdraw stored gas. In non-compensated operation, approximately half of the cavern's gas capacity is available for withdrawal, with the remaining gas being required to keep the cavern above the sendout line pressure. However, this remaining gas cushion can still be accessed if needed by injecting brine into the cavern space to displace the remaining gas from the cavern.

Salt locations suitable for storage in proximity to significant natural gas distribution systems have been found both onshore and offshore many LNG importing areas of the world. The least impact on the community, and the most physically secure facility would be one in which the LNG ship mooring and unloading and the cavern storage and pipeline connections would all be at sea. The following factors are favored for salt cavern storage of LNG.

1) Offshore terminal locations far from populated areas and congested ports will heighten community acceptance and reduce security concerns.

2) The use of salt caverns can result in an LNG import terminal that compared to a cryogenic tank based terminal is much more secure, is much less expensive to build and operate, and can have both higher storage capacity and higher take away capacity.

3) The application of conventional salt cavern storage technology, augmented by new technology in the area of pumps, heat exchangers and facility design, could marry LNG and salt caverns into a highly secure, economical and flexible method to expand the importing nation's energy supply.

4) Salt cavern gas storage facilities have very high deliverability instantaneously available to the pipeline system, far higher than LNG vaporization capacities in conventional LNG terminals.

5) Each cavern is engineered according to use. Project parameters include storage size, delivery rate, creep tolerance, and storage temperature. To form a salt cavern, one must drill through the overlaying strata down into the salt formation to the calculated cavern location, and wash the cavern to the appropriate size.

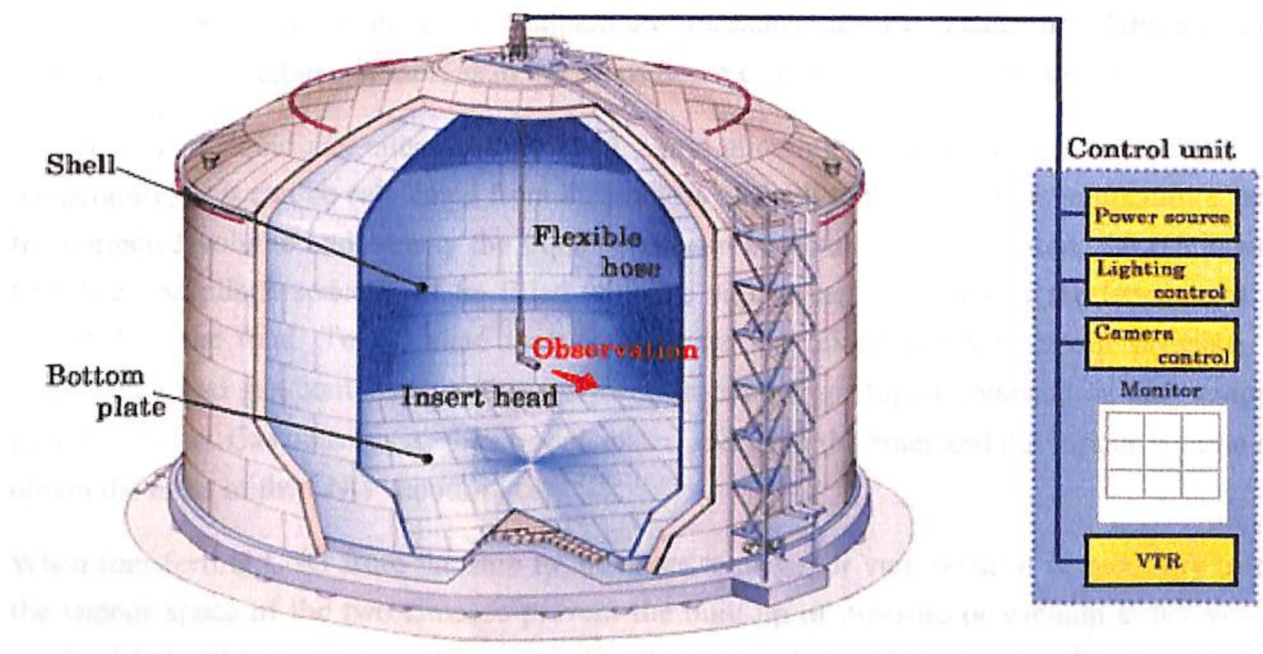
6) Cavern sizes range from 0.4 Million - 40 Million Bbls with pressures ranging from 800psig-4000psig.

7) The wall of the completed cavern has a rough phenolic-like appearance and will not leak under normal operating conditions. Salt cavern creation, solution mining, cavern operation, maintenance, and gas metering are well-documented disciplines within the energy storage business.

8) However, salt cavern storage principles and cavern operations are relatively unknown to those in the LNG trade. In fact, the use of salt caverns for storage and delivery of hydrocarbons is so prevalent in the industry, that most of the people in the energy business are unaware of the extent of cavern use.

Chapter- 5

Measurement and Monitoring Devices



Chapter- 5

Measurement and Monitoring Devices

5.1 Measurement of tank contents: -

Measurement and custody transfer of LNG are complicated by a number of its features. While volume of liquid, if determined accurately, provides some indication of its commercial value, this is insufficient unless linked with simultaneous data on density and/ or calorific value of the liquid and the vapour in equilibrium with the letter.

LNG being at all times close to its boiling point even the measurement of liquid volume can be difficult owing to ill- defined liquid surface level; in additional dimensional changes in metering equipment, particularly tapes, may have taken place owing to temperature change. Depth gauging in LNG tank must, therefore allow for tape contraction. In order to determine the real liquid content of an LNG tank it must, furthermore, be born in mind that vessel calibration at room temperature will not be longer be accurate at -162^0C and that a correction must be applied. A further allowance must be made in the case of ships tankers for inclination, i.e. list and trim of the vessel. Depth gauging in a cryogenic tank is often done by temperature measurement by means of platinum resistance thermometers in a tabular sensor, as in the Trans Sonic custody transfer level system.

The density of liquid can either be measured, again allowing for instrument changes due to its low temperature, or it can be calculated from an analysis of the liquid and from its temperature, and from the corrected volume and density the liquid mass can be obtained. In addition, the reminder of the tank (i.e. the ullage space) will be filled with the vapour and the mass of the letter must also be included in the total. To calculate the vapour mass the ullage volume, vapour pressure, vapour temperature and gas composition (this can be calculated from liquid composition and temperature) need be known. Gas density can then be calculated and from the latter and the vapour volume one can obtain the mass of the LNG vapour in the tank.

When transferring LNG from the ship to the shore tankage, or vice versa, it is necessary to connect the vapour space of the two tanks to prevent the built-up of pressure or vacuum either vessel. The result of balancing pressure is the reverse transfer of a volume of vapour equal to that of the liquid pumped in the direction of transfer. Allowance must be made for this effect in all calculation.

The calibration of the LNG tanks, i.e. establishing a correlation between depth of liquid and its volume, much as that of any other tank, is effect either by direct measurement and calculation, or by the so called water meter method. In the letter case measured quantities of water are introduced and the level of water in the tank is measured.

The method is usually more accurate than measuring tank dimensions since irregularities in tank shape and the inevitable sagging of the measuring tape have to be corrected for it tank volume are calculated from tank dimensions and liquid level.

In either case the low temperature of cryogenic liquids introduces additional problems. If tank volume is calibrated at 200C the capacity of the tank at any other temperature, assuming linearity of expansion and the absence of constraints, is given by

$$V_t = V_{20}(1 - 3\theta)$$

Where θ is the linear expansion coefficient of the surface between temperatures of 20^0C and t. in fact, expansion over the range $+20^0$C to -162^0C is not usually linear and furthermore the expansion or contraction of a rigidly backed or supported tank does not follow the theoretical volumetric expansion rule. Calibration should, therefore, be carried to the lowest possible temperature and gauging correction tables must be prepared on this basis.

5.2 Monitoring Device of tank

Overall system outline: -

The basic configuration of the system is similar to the monitoring device for in-ground tanks, consisting primarily of a "camera unit" that incorporates a camera, an "illumination unit" to light up the tank, a "control unit", and "cables" to connect the devices, and their storage stands.

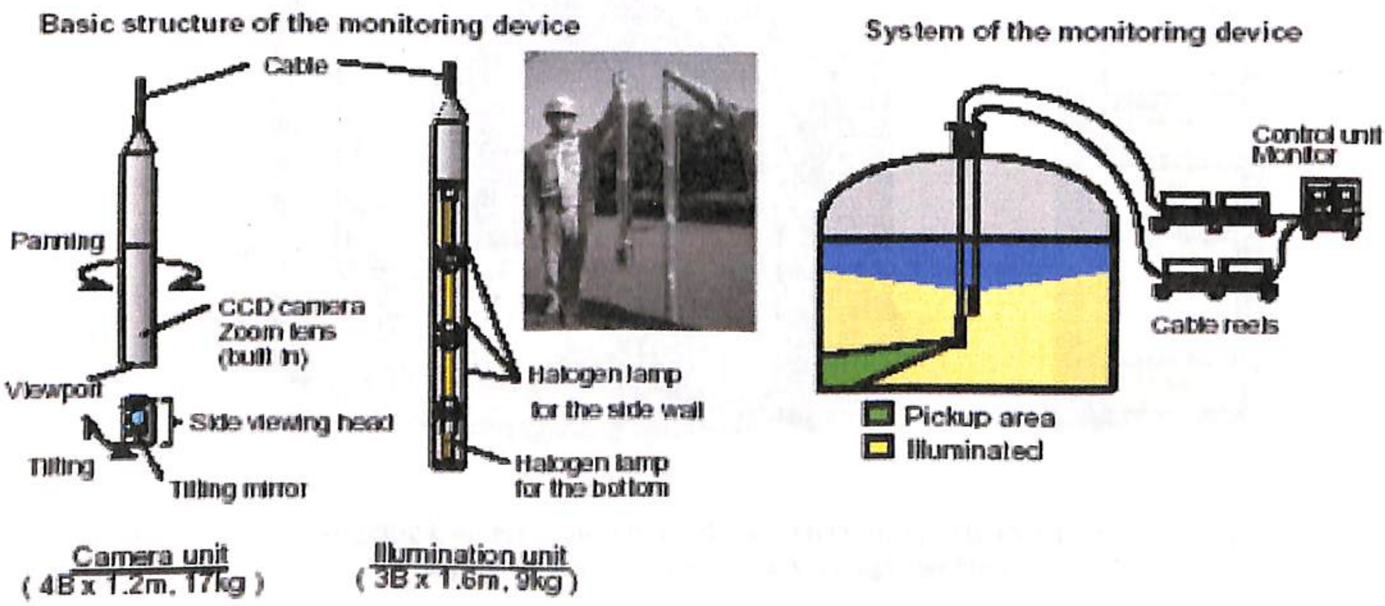


Figure 5.1: Depiction of the device (For In-ground or Underground storage Tanks)

Source: Paper presented in 14th International Conference & Exhibition on Liquefied Natural Gas by Hiroyuki Ishiyama Production Engineering Sect. Tokyo Gas Co., Ltd.

The camera unit and illumination unit are each suspended inside the tank from the tank nozzle by their own cables. On the outside of the tank, there is a cable reels for winding in the cables, and a control unit where a monitor is mounted for controlling the camera and illumination. Vertical movement of the devices inside the tank is accomplished by manually raising and lowering the cable. When the position has been decided, it is fixed by fitting a stopper to the cable where it emerges from the nozzle.

In order to prevent a device accidentally falling, a wire that is wound onto a manual winch is fitted to the cable as a permanent backup. Low temperature specification cable is used for the part of the cable that enters the tank and is cooled, but ambient temperature specification cable is used for other parts of the cable in order to keep costs down and to make the cable easier to handle. The individual devices are outlined below.

5.3 Cryogenic Camera Equipment

The storage system is safe long-term because LNG is not corrosive and there are no deteriorating factors. At some time, however, tanks may need to be inspected for soundness. The decommissioning inspection method, where the internal area is checked visually, is generally used.

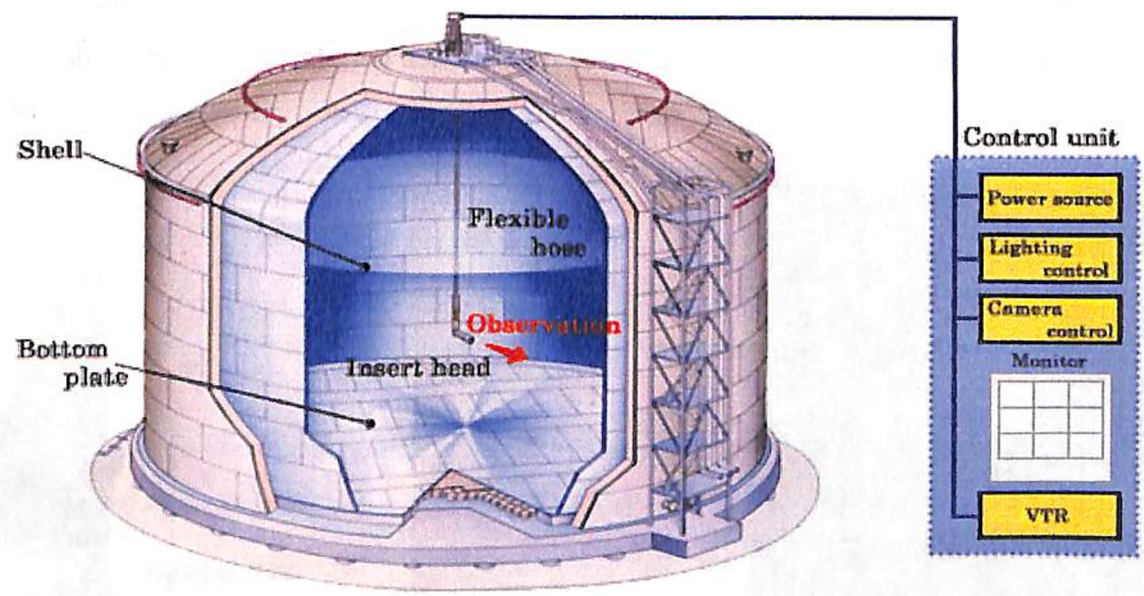


Figure 5.2: Cryogenic Camera Equipment, Source: MITSUBISHI HEAVY INDUSTRIES, LTD. (http://www.mhi.co.jp/ydmw/e/tank/lng/ag/index.htm)

This method poses difficulties for the operators of LNG bases, including economic losses, because the tank system must be shut down for a long period to conduct the inspection.

The suspension unit is installed on the top of a tank. The head is suspended inside the tank. The power supply, control unit and TV monitor are installed in a safe place.

Aluminium alloy tank observation screen	9% Ni steel tank observation screen

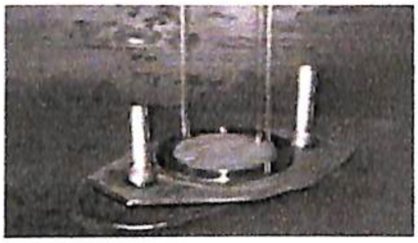


Figure 5.3: Bottom plate

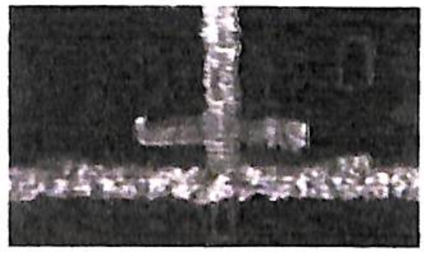


Figure 5.4: Shell

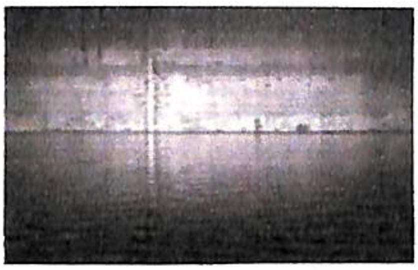


Figure 5.5: Shell

Figure 5.6: Bottom plate

- Photographs, which show internal area of a tank, are taken from the monitor display; they are not as sharp as the original.

Figure 5.7: Suspension unit

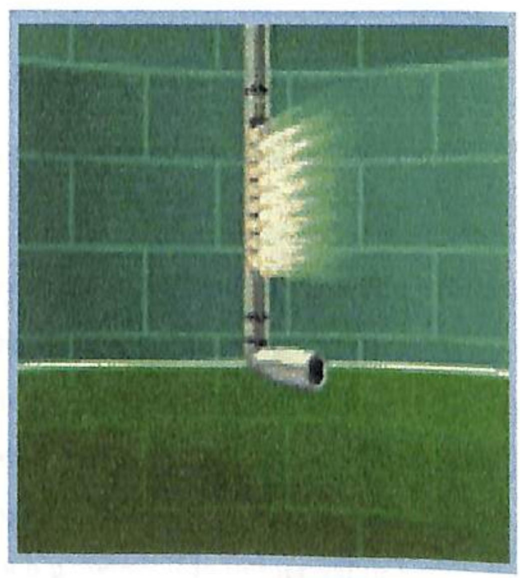


Figure 5.8: Insert Head

(Source: MITSUBISHI HEAVY INDUSTRIES, LTD., http://www.mhi.co.jp/ydmw/e/tank/lng/ag/index.htm)

5.3.1 Insert Head

This unit comprises a camera unit, a pan and tilt unit with a lighting unit. The entire internal area of a tank can be observed because the length of the flexible hoses for suspension can be adjusted and a pan and tilt unit is available.

5.3.2 Feature

- The world's first system, which allows observation of the entire internal area of a cryogenic (-162 degrees C.) LNG storage tank even through liquid without stopping operation.
- Integral camera and lighting construction allows easy installation with a hanging nozzle.
- Small size and lightweight design makes it easy to install the system. The system can be installed when requested by the customer.
- Can be installed on an existing nozzle without any risk of gas leak.
- Explosion-proof construction allows the system to be used in a flammable gas atmosphere.

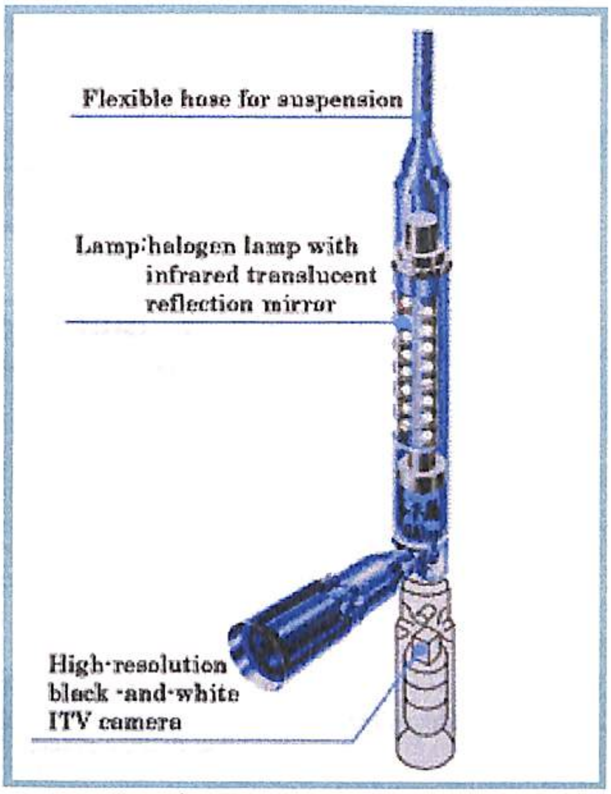


Figure 5.9: Insert Head
(Camera and Lighting Unit)

Source: MITSUBISHI HEAVY INDUSTRIES, LTD. (http://www.mhi.co.jp/ydmw/e/tank/lng/ag/index.htm)

5.4 Illumination Units

The illumination unit incorporates a double-tube halogen lamp designed for low temperature use. A tungsten halogen lamp was chosen in the illumination unit. The heating of the tungsten filament in a halogen atmosphere emits a very bright light. Since the halogen atmosphere allows the majority of the tungsten, vaporized from the filament during use, to be redeposited on the filament during lamp cool-down (sometimes called the halogen cycle), the bulb life is long. However, if a tungsten halogen bulb is turned on when the it's glass is at a very low temperature, such as when it is immersed in LNG, the low temperature prevents the halogen cycle inside the bulb from occurring.

As a result, the luminosity of the bulb falls sharply and bulb life is significantly shortened. Therefore, the illumination lamps were constructed by inserting the bulbs into a double walled structure where an outer glass tube prevented the LNG form contacting the surface of the halogen bulb directly (see Figure 5.1). To allow illumination of the sidewalls, multiple lamp sets of two halogen bulbs each were used (end to end) in the one outer glass pipe, see Figure 5.10. The use of both shorter and more powerful halogen bulbs enclosed in their outer tube allowed Tokyo Gas to effect size reduction of the illuminating unit. (Figure 5.10 Structure of the halogen lamp designed for low temperature use)

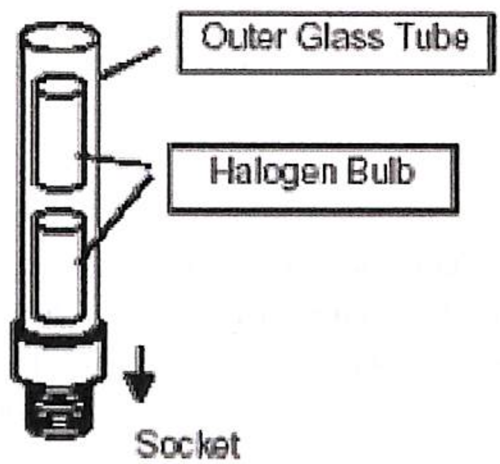


Figure 5.10: Structure of the halogen lamp
Source: Paper presented in 14th International Conference & Exhibition on Liquefied Natural Gas by Hiroyuki Ishiyama Production Engineering Sect. Tokyo Gas Co., Ltd.

In in-ground tanks, the inside wall is an effective stainless steel membrane that reflects the light from the illumination unit and contributes to enhancing the degree of illuminance in the tank, enabling bright images to be obtained. As opposed to it, many above-ground tanks have inner vessels made of 9% Ni steel, and apart from weld lines, the surfaces are painted with a dark colored anti-rust treatment, so they reflect relatively little light. Compared with stainless steel membranes, the insides of the tanks look dark and visibility is poor. Because of this, and because only a small amount of light is reflected, observation requires a high degree of illuminance. The illumination unit ensures the required degree of illuminance by fitting reflector panels to the illumination unit used for in-ground tanks so that the light is concentrated in the direction being viewed. The shapes of the reflector panels and their positioning relative to the lamps were determined by simulation. Since the panels need to orient the light in the direction being viewed, they are designed with a panning/rotation mechanism like that of the camera unit. The lamp section is covered with stainless steel mesh to prevent components falling into the tank in the unlikely event that they become detached.

5.4.1 Cables

The visual monitoring device uses cables to connect both the camera unit and the illumination unit to the control unit fitted outside the tank. These cables have low temperature specifications so that they can be used at the LNG temperature. The cables have the important role of suspending the devices inside the tank. For that reason, they have an integrated structure of stainless steel wire and stainless steel mesh, and in order to prevent anything accidentally falling, they are designed to have adequate tensile strength, including the parts connected to the devices. At the same time, in order that the operators can manipulate them without additional equipment, special attention was given in the design to the thickness of the cable covering and the weight of the intervening material, with the result that the cables are substantially lighter than conventionally-designed cables per unit length.

5.4.2 Control unit

The control unit consists primarily of a PC to operate and control the equipment, a temperature controller to control the internal temperature of the vacuum-insulated vessel, a video monitor, an image processing unit for adjusting the brightness and contrast of the images, and a UPS. The control unit controls the viewing direction, the zoom lens, controls and monitors the device temperatures, and can adjust the degree of illuminance and image quality.

In addition, there is a mirror-image function. The mirror-image function electrically inverts the image left-right. When the visual monitoring device uses a mirror for lateral observation, the image obtained is reversed left-right, so the mirror-image function is used to correct the orientation of the image. This function is turned off when the side viewing head is not used.

5.4.3 Investigations Regarding Illumination Unit

Investigating form of illumination: - Tests were conducted with pieces of 9% Ni steel having welding lines and painted similarly to the insides of actual tanks. The steel pieces were placed at a 30 m distance and observed utilizing existing monitoring devices with varying degrees of illuminance, to investigate the degree of illuminance that would give image quality on the screen that was at least as good as that obtained with existing methods. Based on these tests, a target of 10 lx was set. Ways of enhancing the performance of the illumination unit to achieve the target degree of illuminance were investigated. It was decided to fit reflectors to the lamps used in the existing monitoring device for in-ground tanks because that allowed illumination to be enhanced while retaining a lamp output similar to that of the previously-developed device. The form of the reflector needed to take into consideration factors such as weight and ability to withstand low temperatures, so it was decided to use a reflector made of mirror-finish aluminum. It was also made possible for the reflector to be detached if required.

5.4.4 Illumination simulation: -

Simulations were performed to find the degree of illuminance achieved at the surface being observed with different arrangements for the lamp and the reflector. Figures for reflectivity of the insides of the tanks were required in order to perform the simulations, so measurements were also taken of the reflectivity of a 9% Ni steel surface painted to the same specifications as the insides of the tanks.

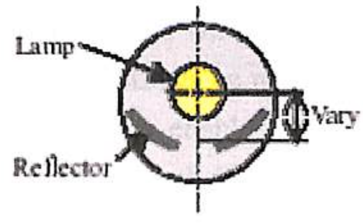


Figure 5.11: Illumination unit section layout
Source: Paper presented in 14th International Conference & Exhibition on Liquefied Natural Gas by Hiroyuki Ishiyama Production Engineering Sect. Tokyo Gas Co., Ltd.

5.4.5 Thermal analysis: -

In gas, a halogen lamp is very hot, exceeding 500°C, and it was expected that fitting a reflector in close proximity to the lamp would produce even higher temperatures in the lamp. Furthermore, the reflector would also be heated to a high temperature by the heat of the lamp. Thermal analysis was conducted to predict the rise in temperature, and the results were found to be within the allowable range. An experimental unit equivalent to the real unit was fabricated, and it was confirmed that there were no problems with this unit.

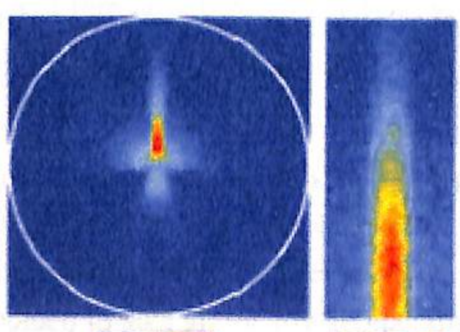


Figure 5.12: Example of illumination simulation
Source: Paper presented in 14th International Conference & Exhibition on Liquefied Natural Gas by Hiroyuki Ishiyama Production Engineering Sect. Tokyo Gas Co., Ltd.

5.4.6 Panning/rotation mechanism: -

Fitting a reflector means that the illumination unit must be made so that it can be steered in the direction of observation. For the unit under development, it was decided to rotate the reflector and lamp together as a single unit. It was decided to use a drive mechanism fitted above the reflector and lamp to enable panning/rotation. In comparison with the camera unit, the illumination unit has a number of relatively thick wires for the lamps, so it was anticipated that a larger torque would be required to counter the bending resistance of the wires when rotated. In order to align the lamp with the position of the camera unit it would sometimes be necessary to make close to a complete turn, so in order to ensure ease of use, it was decided to enable the camera unit to rotate quickly with a speed of 2 rpm, faster than the previous 0.5 rpm speed. For that reason, it was considered that the drive mechanism would be need to provide greater torque than required for the camera unit. The amount of torque required for rotation was obtained based on the experimental data from the development of devices for in-ground tanks, and this showed that the existing motor and reduction gears did not provide sufficient torque. Consequently, a motor one size larger was selected. A new design was also used for the reduction gears.

5.4.7 Investigating the Observation Method

With in-ground tanks, the cables are fed out from storage stand and wound back onto the storage stand as the devices are lowered and raised, but longer cables are required for above-ground tanks because the nozzles are in high locations, and because the cable reels and control unit are located outside the dike in order to meet the requirements of the design concept of being able to manhandle the system without additional equipment. Using a system and observation methods like those used with existing units would increase the cable costs and require additional staff to handle the cables, making the setup less easy to use. For these reasons, an observation method suitable for above-ground tanks was investigated.

Basically, low temperature cables are expensive and need to be handled with special care, so it was decided to keep the length of low temperature cable as short as possible. This decision led to the approach of only using low temperature cable for the sections that enter the tank, and using ambient temperature specification cable for other sections. In order to reduce the number of people required to make observations, it was also decided to take all the low temperature cable onto the roof of the tanks and wind it onto a temporarily installed winding stand. By letting the cable out from that position when taking measurements, the number of people required for the work is about the same as required for in-ground tanks.

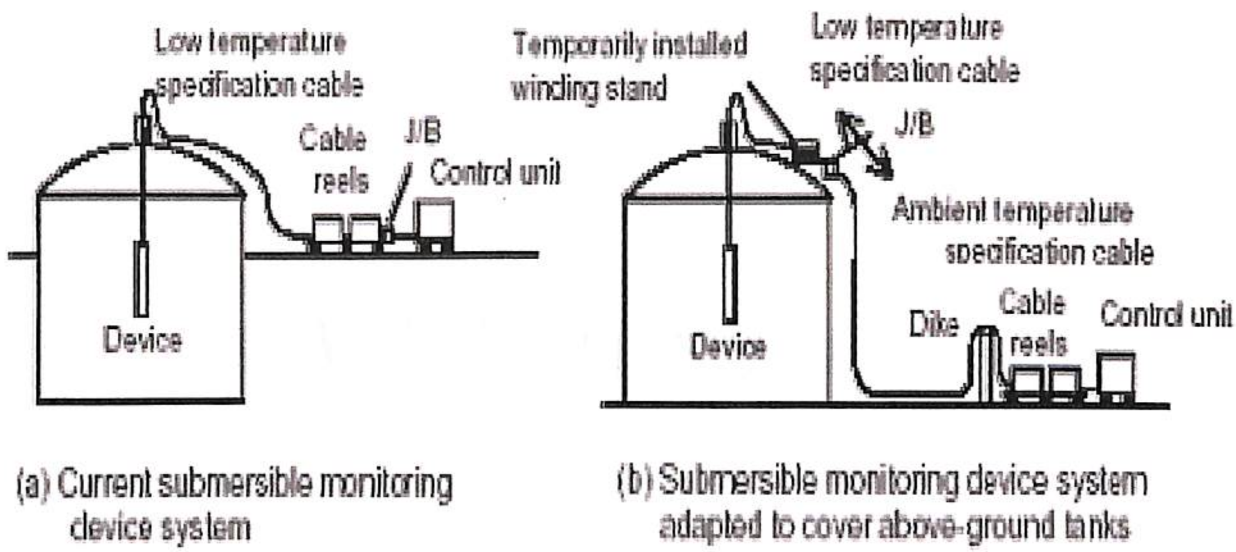


Figure 5.13: Compression of submergible monitoring device system
Source: Paper presented in 14th International Conference & Exhibition on Liquefied Natural Gas by Hiroyuki Ishiyama Production Engineering Sect. Tokyo Gas Co., Ltd.

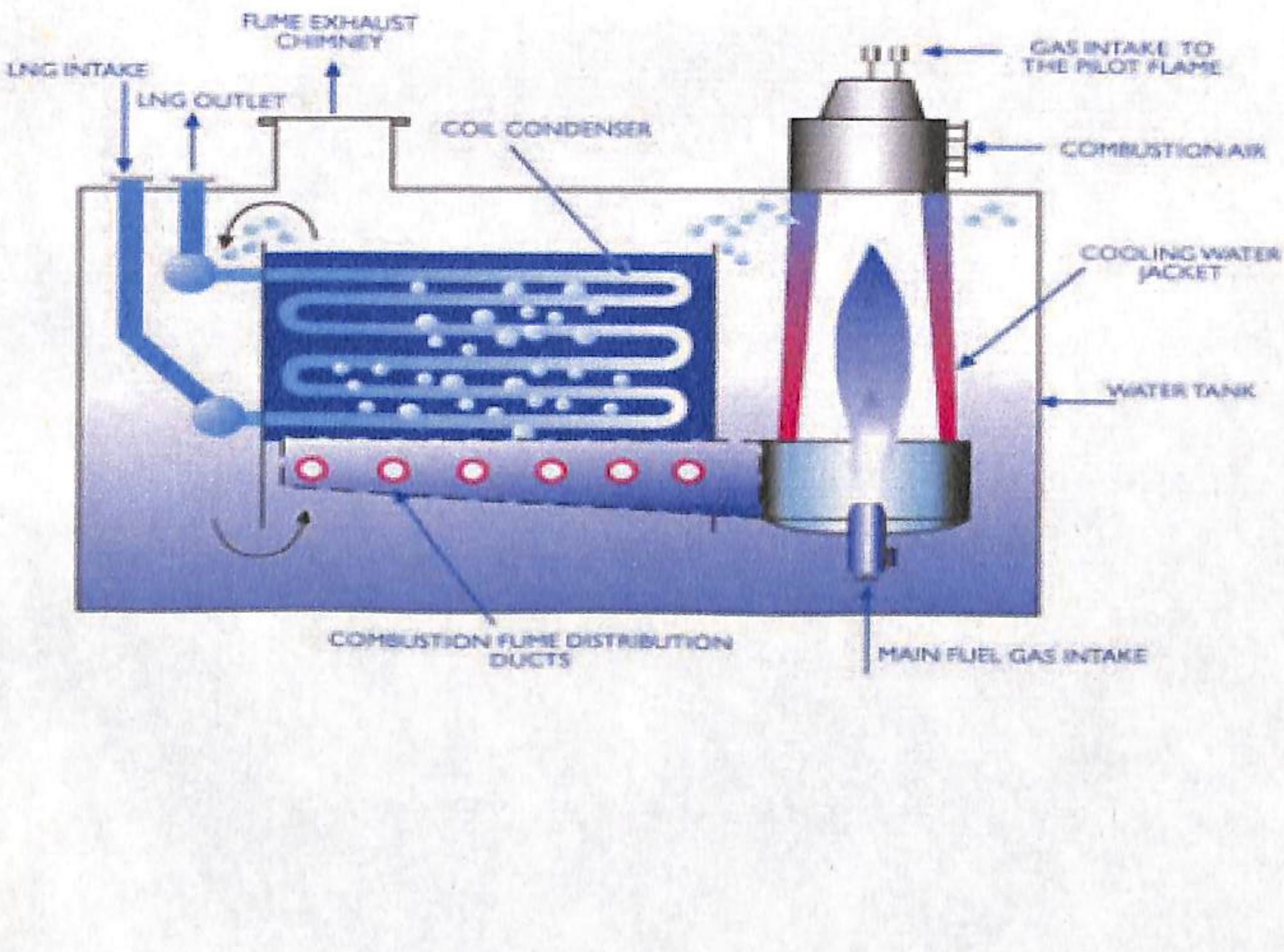
5.5 Investigations Concerning Cables

5.5.1 Cable length

Taking into account tanks operated by companies other than Tokyo Gas, and in order to enable the devices to be used for observations of both above-ground and in-ground tanks, it was decided that the lengths of low temperature specification cable and ambient temperature specification cable would be as follows. Low temperature specification section: 90 m Ambient temperature specification section: 140 m the two cable sections were connected using junction boxes. In the original units, the junction boxes were fitted on the cable reels, but with the modifications, it was decided to install the junction boxes on the shoulders of the tanks. In order to shut off any gas passing through the low temperature cable, it was decided to maintain a permanent flow of N_2 into the junction box.

Chapter- 6

LNG Re-gasification



Chapter- 6

LNG Re-Gasification

There are several methods to regasify or vaporise the stored LNG for export. Conventional LNG import terminals feature regasification methods such as:

1. Open Rack Vaporisers [ORV]
2. Submerged Combustion Vaporisers [SCV]
3. Direct Seawater Shell & Tube Vaporisers [STV, peak shavers and carriers]
4. Intermediate Fluid Vaporisers [IFV]
5. Condensing Intermediate Fluid Vaporisers [C-IFV]
6. Shell and Tube Vaporisers
7. Steam Vaporisers (SV)
8. Forced air Circulation LNG Vaporiser
9. Natural Draft Air Fin Vaporizers (Conventional LNG Vaporizers System)
10. Hot Air Draft Super heater With Air Fin Vaporizer (Hav)

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 Open Rack Vaporisers 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 weather to use ORVs or SCVs. If the seawater temperature is below approximately 5^0C, ORVs are usually not practical because of seawater freezing. 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' utilization process.

6.1 Open Rack Vaporisers (ORV)

Seawater in an open rack, falling film type arrangement vaporises LNG passing through the tubes (see Figure 2). 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 traveling band screen may be provided for further removal of suspended solids to prevent blockage or damage to the open rack vaporisers.

Electro chlorination 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. Because this method is very cost-efficient to operate and consists of a simplistic structure, it is easy to operate and maintain. It is the safest and most reliable vaporizer. ORVs are normally used for a base load due to these features. Optimal design technology for heat transfer tube has created the world most cost-efficient; high performing ORV.

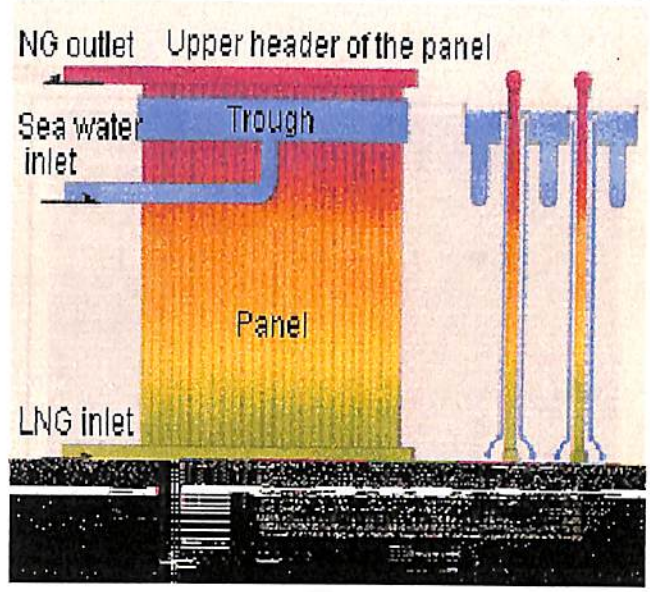


Figure 6.1: "Open Rack" LNG Vaporization
(Source: TOKYO GAS Co., Ltd., http://www.tokyo-gas.co.jp/lngtech/orv/index.html)

6.1.1 How this technology helps

Customers considering installing new vaporizers or revamping existing equipment can now take advantage of the most reliable and high performing ORV. The ORV is also the world's most economical for lifecycle costs including maintenance.

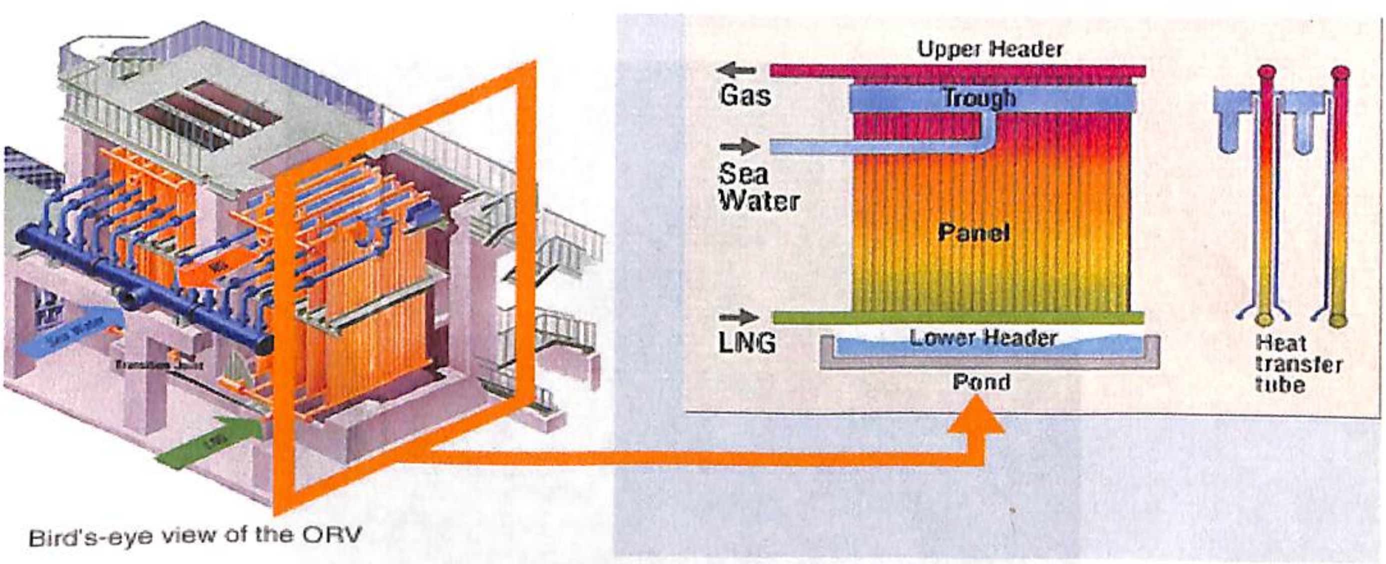


Figure 6.2: A bird's-eye view of the ORV and shows an outline of the panel composed of heat transfer tubes (Source: TOKYO GAS Co., Ltd., http://www.tokyo-gas.co.jp/lngtech/orv/index.html).

6.1.2 Features

1. ***Optimum design technology reduces construction costs.***

In order to enhance thermal efficiency, Tokyo Gas revised design methods wherein conventional trials were used as a base*[1]. The newly developed optimal design technology enabled to determine the most suitable shape of heat transfer tube in an efficient manner, using numerical analysis. The newly developed HiPerV (HiPerV is an acronym for High Performance ORV) utilizes the optimal design technology*[2] to greatly increase vaporization performance in addition to:

- ❖ Considerably reducing construction costs (20 percent less) through decreasing the number of tubes by half, and
- ❖ Reducing installation space by (30 percent less)

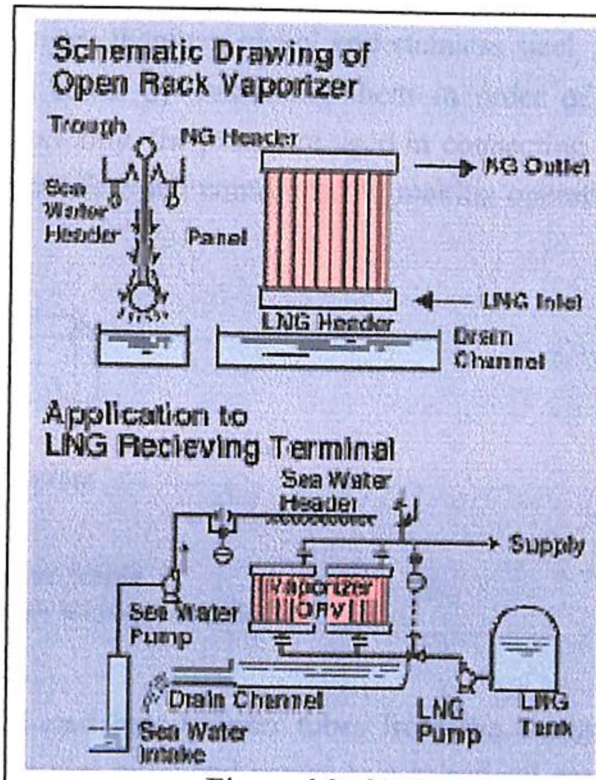


Figure 6.3: ORV
Source: Courtesy Kobe Steel, Ltd

Figure 6.4: ORV at Tokyo Gas's Ohgishima Terminal (First HiPerVs)
Source: Tokyo Gas Co., Ltd. (http://www.tokyo-gas.co.jp/techno/)

2. *Enhancing operations*

In 1985, Tokyo Gas developed and began using explosive joints so that quick startup from ambient temperature is possible without cool-down running*[3] which was required in conventional operation. Explosive joints are made from layered pipes of aluminum, titanium, nickel and stainless steel. The joints are structured so that they can absorb thermal stress by combining them in order of the coefficient of thermal expansion from large to small. Currently, the joints are used in connecting off-site LNG pipes to vaporizers. The joints have improved safety and contributed to making operations easier.

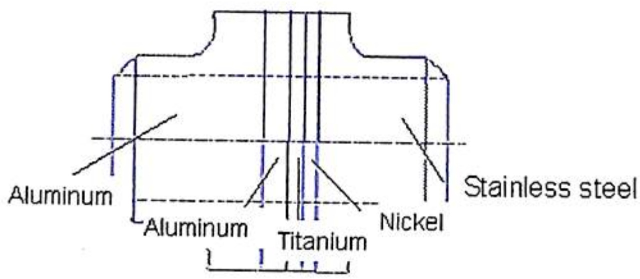


Figure 6.5: Explosive joints
Source: Tokyo Gas Co., Ltd. (http://www.tokyo-gas.co.jp/techno/)

3. *Enhancing maintenance*

From 1998 Tokyo Gas adopted anticorrosive material-clad heat transfer tubes from the extrusion forming stage. The cladding is made from an aluminum-zinc alloy and serves as a sacrificial anode. Utilizing the clad heat transfer tubes makes repair of the aluminum-zinc alloy coating*[4] unnecessary resulting in considerable savings on maintenance costs.

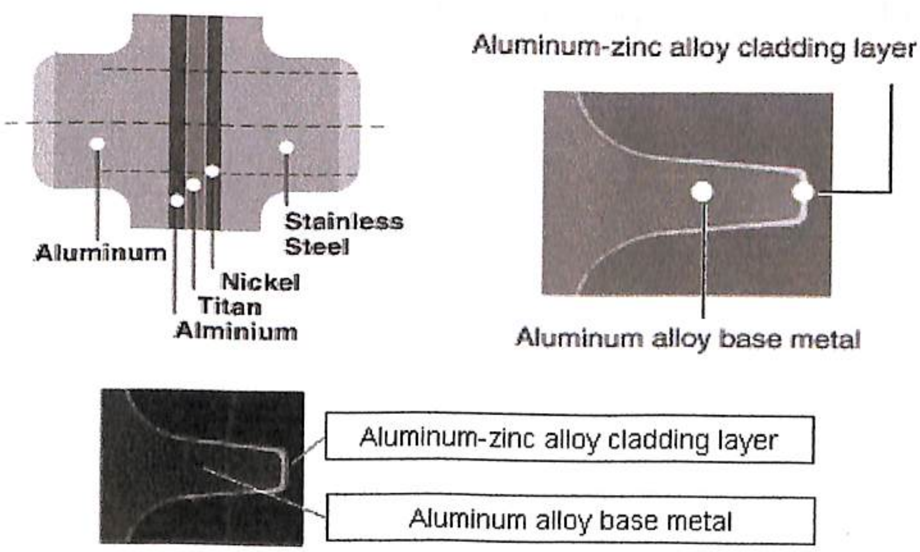


Figure 6.6: Anticorrosive material-clad heat transfer tubes
Source: Tokyo Gas Co., Ltd. (http://www.tokyo-gas.co.jp/techno/)

[*[1] Repair of the aluminum-zinc alloy coating

Because seawater is used as the medium to heat ORVs, the heat transfer tubes are in a very corrosive environment. To prevent corrosion of the ORV heat transfer tubes, thermal spraying of an aluminum-zinc alloy was conventionally used. However regular re-spraying was necessary since this method was prone to wear and tear.

***[2] Cool-down running**

Vaporizers are made from an aluminum alloy and the connecting off-site LNG pipes are made from stainless steel. Flange is used to connect these.

When quickly starting the vaporizer from when it is stopped, there is a danger of LNG leaking through gaps created between the flanges because of the temperature change caused by the differing coefficient of linear expansion when LNG is piped through.

Accordingly, in order to maintain the flange at a low temperature to prevent LNG leakage, a small amount of LNG was continuously piped through, even when the vaporizer had stopped. This is called cool-down running

***[3] Utilizing the optimal design technology**

Developing a heat transfer tube, which has a larger diameter than that of conventional types and adopts optimized shapes of fins for the inside and outside surfaces.

It is possible to release large amounts of seawater uniformly despite heat-resistant ice forming on the outside of the heat transfer tubes because the fin grooves prevent most blocking.

***[4] The design method based on the experiment**

The conventional design methods adhered to star-fin type tube forming developed in 1984. Overall design and appropriate shape of tubes were determined through trials in accordance with separate design conditions.**]**

6.2 Submerged Combustion Vaporisers [SCV]

SCV's are usually supplied as self-contained units and commonly used in terminals as booster units to meet periods of peak demand, i.e. `peak shaving'. These vaporisers use the technique of submerged (under water) combustion. The products of combustion from the burner are discharged directly into a water bath beneath a tube bundle carrying the LNG. The cooled products of combustion are discharged to air via a vent stack. The SCV consumes about 1.3 % of the throughput as fuel. This system was not selected, mainly because of concerns related to reliable operations under the influence of vessel motions.

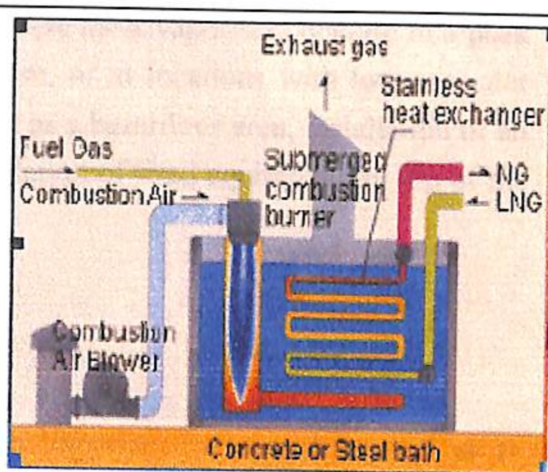


Figure 6.7: Submerged Combustion Vaporiser
Source: Sumitomo precision products

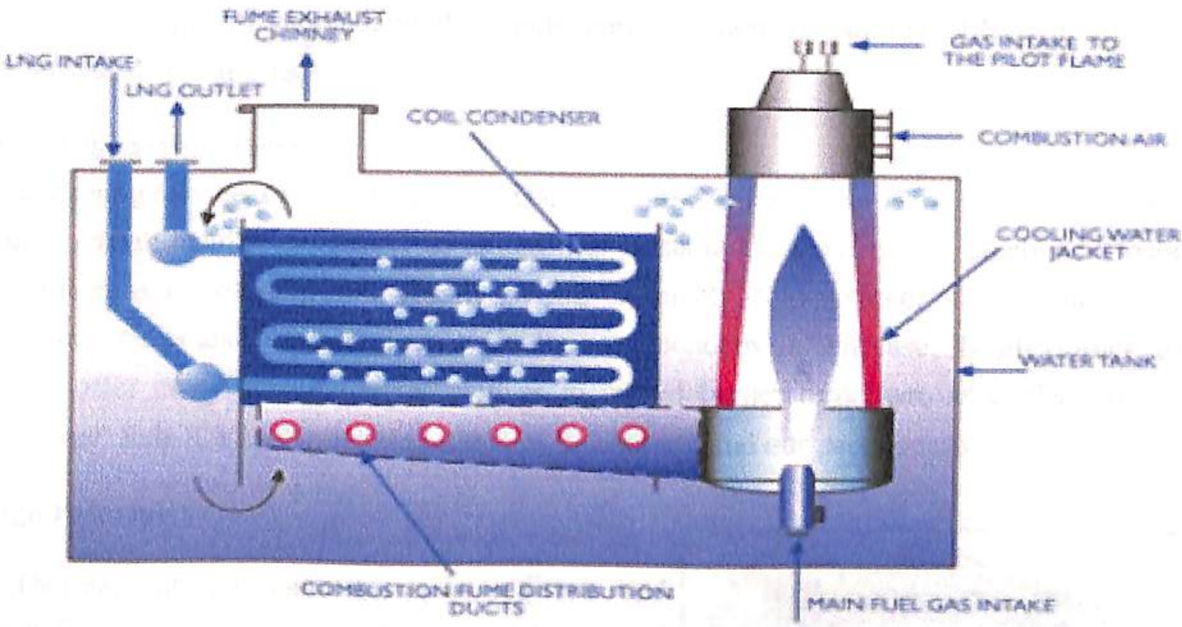


Figure 6.8: Submerged Combustion Vaporiser
(Source: BHP billiton, http://lngsolutions.bhpbilliton.com/LNGbg.asp)

SCV's offer a low [installed] cost, proven technology that features a small footprint and quick ramp rates. High operating costs [fuel gas rate may be as high as 1.5% of export rate] make it uneconomic for baseload applications, especially in areas where the seawater temperature is high enough to provide a driving force for the vaporisers. The technology is suitable for peak shaving applications or in circumstances where peak demand coincides with low seawater temperature.

This explains why SCV is the method of choice in the USA, where most vaporisers operate in a peak shaving capacity and are often installed either away from shore, or at locations with low seawater temperature. Because the entire deck area on a floater is classed as a hazardous area, installation of an SCV has some challenges. The IMO code does not allow installation of fired equipment on top of the LNG storage tanks.

6.2.1 T-Thermal Sub-X® Vaporizer

1) LNG Baseload Service

For base-load service, operation of the Submerged Combustion Vaporizer Systems **(Licensed as T-Thermal Sub-X® Vaporizer by *T-Thermal Company*)** is the primary means of LNG vaporization on a continuous basis. Typically, vaporizers for base-load service have utilized a large "Single Burner" to minimize emissions as well as pH monitoring and control of the water bath chemistry to minimize effects of low pH. In addition, Sub-X® Vaporizer Systems are installed and operated utilizing available warm water to supplement the single burner system to vaporize LNG or independently operate the Sub-X® Vaporizer.

2) LNG Peak-shaving Service

For peak-shaving service, operation of the T-Thermal Sub-X® Vaporizer is the primary means of LNG vaporization when insufficient supply of natural gas exists in the transmission pipelines. Operation of these facilities is intermittent and usually during extremely cold weather. Due to the intermittent operation, emissions and pH control are typically not a concern. In this case, "Multi Burner" Sub-X® Vaporizers offer many advantages, as well as increased burner turndown, as evident by over 190 "Multi Burner" Sub-X Vaporizer installations by T-Thermal and our past licensors.

3) Design Principles

The T-Thermal Sub-X® Vaporizer is an indirect fired heat exchanger with the burner and process tube coil all contained within a single vessel. The design is based on the Sub-X® (submerged exhaust) principle whereby the burner combustion products are discharged into a water bath, which is used as the heat transfer media for vaporizing the LNG in the tube coil.

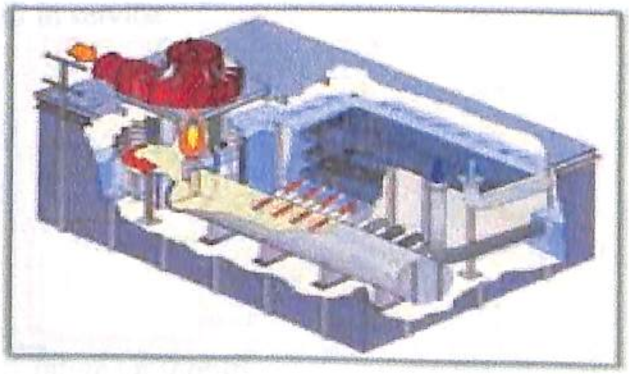


Figure 6.9: T-Thermal Sub-X® Vaporizer
Source: T-Thermal Company (http://www.selasfluid.com/t-thermal/technologies.htm)

In the Sub-X® system, the burning takes place in a distributor duct that is immersed in a water bath. The products of combustion are exhausted directly into the water bath at a point below the surface. Exhaust of the combustion products impacts a highly turbulent motion to the water and many gas bubbles are formed. The direct gas/water contact creates a lift action, which causes the mixture to rise. A weir is employed to confine the lift action so that there is a high recirculation rate of water up through the weir space and over the weir ends.

The heat exchanger tube coil is immersed in the water in the weir space above the exhaust gas distribution system, so that the gas/water mixture scrubs the surface of the tube coil at an extremely high velocity. A high outside heat transfer coefficient is achieved in three distinct steps:

- Heat and mass transfer between the products of combustion and the water bath.
- Transfer of heat from the gas-water mixture to the coil.
- Transfer of heat from the tube coil to the process fluid.

Together, these mechanisms enable thermal efficiencies of greater than 95%.

4) Benefits

The patented T-Thermal Sub-X® Vaporizer combines our direct fired-heater experience with proprietary burner systems. In addition, the Sub-X® Vaporizer employs the safety of steam heating, the high response characteristics of a direct-fired heater, and the following benefits unique to the T-Thermal Sub-X® Vaporizer System:

- **Reliability and Experience**
  - T-Thermal Company has more experience in installations of submerged combustion cryogenic vaporizers than all major companies combined
  - 80% share of world submerged combustion vaporizer market
  - Since 1965, 99% of all T-Thermal installations are still in service.
- **System Efficiency**
  - Thermal efficiency up to 98% (HHV)
  - High heat flux with low temperature approach
  - Clean combustion with low emissions
- **Temperature Uniformity**
  - High turbulence and recirculation for maintained temperature uniformity
  - No ice formation

- **Fast Response Due to Heat Storage Capacity of Water Bath**
    - Rapid startup and shutdown without process upset
    - No process liquid carryover
    - Checkout and operation without process fluid flow
- **Safety**
    - No possible flame contact with process fluid
    - No need of insulation for personnel protection
    - Automatic or semi-automatic operation, complete with safety interlocks
    - Since heat exchange medium is water, hazards and handling of ethylene glycol and other heat transfer fluids is eliminated
- **Economy**
    - Fuel savings due to high thermal efficiency
    - Prepiped and prewired for minimal installed cost
- **Design Flexibility**
    - Various cryogenic / low temperature process fluid applications
    - System designs from 10 MM to in excess of 120 MM Btu/hr heat transfer
    - Concrete pit or steel tank installation
    - Customization for site-specific requirements
    - State-of-the-art emission systems to meet environmental requirements
    - Modular assembly
    - Automatic operation

Natural gas will be used as the primary fuel to provide heat and electrical power to conduct operations and service utilities at the facility. Existing technologies will further reduce the emissions from this very clean fossil fuel.

6.3 Direct [ambient] type Vaporisers

Many different sources, e.g. air, seawater, waste heat recovery units, direct fired heaters, etc. could provide the driving force for intermediate fluid, or even direct, vaporisers. The weight and footprint as well as freeze up risk of air coolers makes it an unsuitable candidate for the FSRU application. Waste heat recovery is generally not abundant enough to allow vaporization, and direct-fired heaters are an unwise choice for a floater due to its hazardous area classification. The obvious choice for an FSRU application is seawater. Because of freeze up, bio fouling and corrosion risks, an intermediate fluid is often considered for the actual vaporisation.

Figure 6.10: Direct [ambient] type Vaporiser
Source: Chicago Power & Process

6.4 Intermediate Fluid Vaporiser (IFV)

The IFV uses seawater as the heating medium, but not directly. An intermediate fluid, typically butane, glycol or propane, is vaporised by the seawater and then used, in turn, to vaporise the LNG. A final stage `trim' heat exchanger superheats the produced gas. Owing to the inherent design of the IFV, they are considered to be relatively insensitive to vessel motions and hence suitable for use on an FSRU.

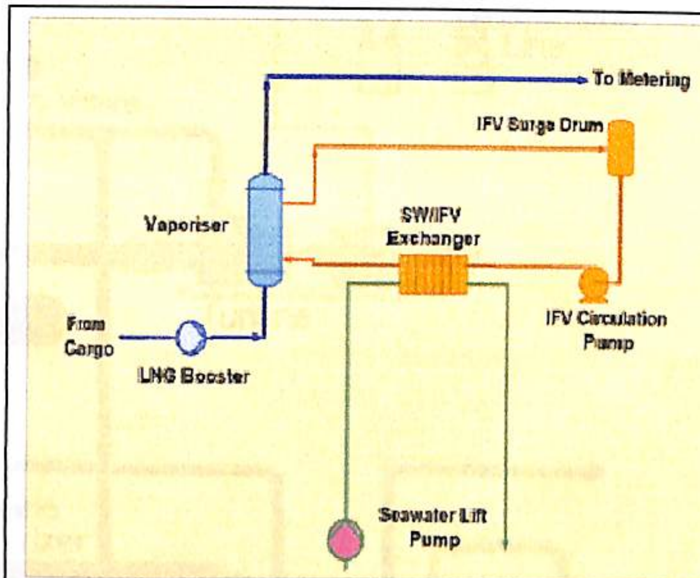


Figure 6.11: Typical flow diagram for an intermediate fluid vaporiser system

Source: From paper*THE APPLICATION OF THE FSRU FOR LNG IMPORTS* by Single Buoy Moorings Inc. and IHC *Gusto Engineering* BV [affiliates of the IHCCaland Group].

Compared to a direct seawater type vaporiser, the use of an intermediate fluid circulation system, adds equipment and controls to the set up. The cost penalty is limited by the use of compact titanium plate heat exchangers for Seawater/Heating Medium heat exchange. The use of compact heat exchangers in LNG/Seawater contacting is not practical due to the freeze up & fouling risk. The operational benefit of reduced freeze up and improved corrosion & bio-fouling management justifies the incremental costs.

LNG vaporization by conventional heat exchangers [e.g. vertical NJN-type Shell & Tube heat exchangers] is a proven technology for peak shavers as well as high capacity applications. The heating medium is typically seawater or a water glycol mixture with a freezing point below –30°C.

6.5 Condensing Intermediate Fluid Vaporisers [C-IFV]

Some IFV type vaporiser designs use a condensing intermediate fluid [C-IFV] like ammonia or propane. Such exchangers use latent rather than sensible heat exchange. Thus, considerable savings on material costs are feasible. This is particularly important if the driving force is provided by seawater, and high-grade material is required. The materials costs are somewhat higher than for glycol water based IFV system, but there is no requirement for an IFV circulation loop. Inspection, Maintenance, Repair & Overhaul costs remain high compared to other technologies.

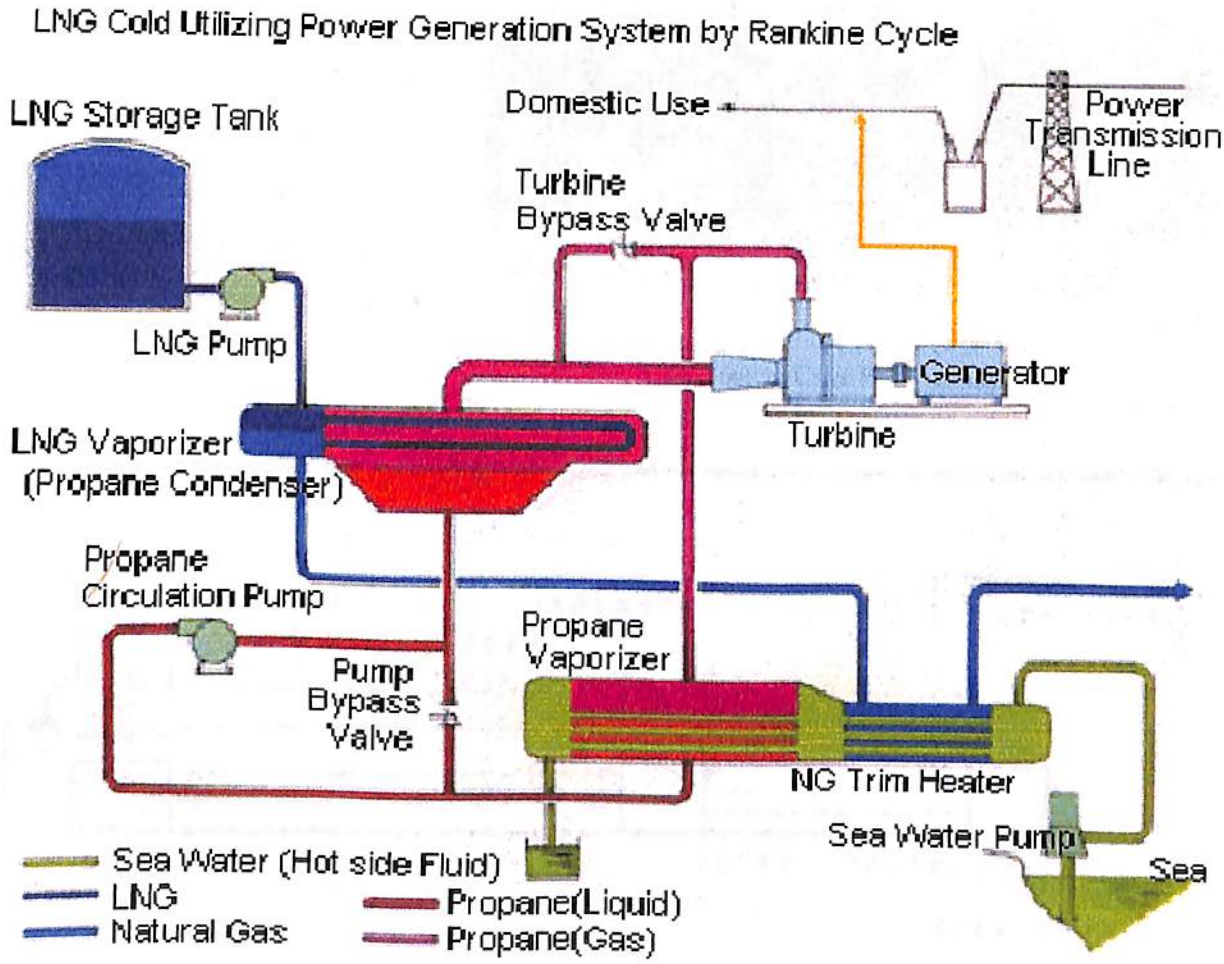


Figure 6.11: C-IFV Synergy [cryogenic power generation],
Source: Osaka Gas

Recent installations in the Far East featured a high level of integration with other industrial developments [e.g. cryogenic power generation and air separation]. With the added value of that synergy, the economics of an import terminal with C-IFV technology improves considerably. At this moment, that synergy is only available in the Far East [Japan, Korea]. Synergy could become a decisive factor in developing regions, where there is a large increase in demand from power generation and industrial development. For the FSRU application, the incremental costs are considered too high.

6.6 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.

Figure 6.12: – Cove Point Vaporisers
Source: Cove Point terminal U.S.

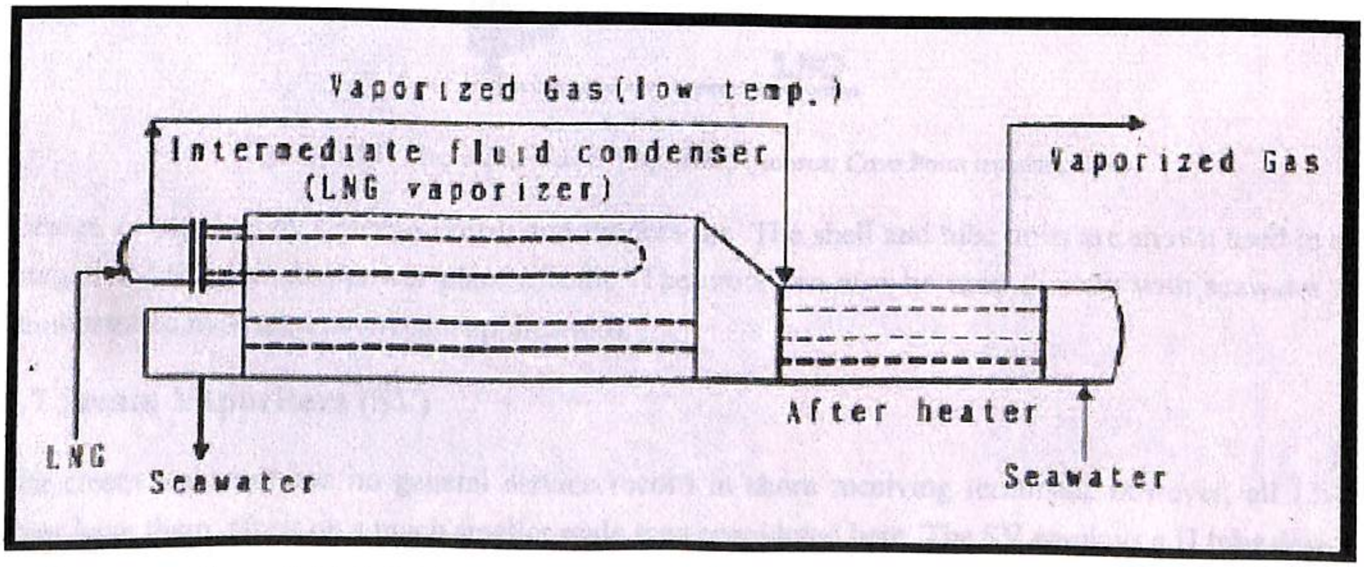


Figure 6.13: Schematic of shell and tube vaporiser with intermediate fluid.
Source: Cove Point terminal U.S.

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.

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 vaporizers, 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 Figure 6.14 below.

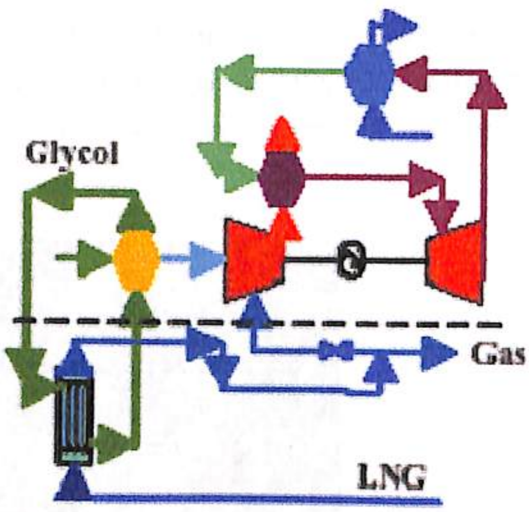


Figure 6.14: Shell and Tube Vaporiser (Source: Cove Point terminal U.S.)

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.

6.7 Steam Vaporisers (SV)

The steam vaporiser has no general service record in shore receiving terminals, however, all LNG ships have them, albeit on a much smaller scale than considered here. The SV employs a U tube design shell and tube heat exchanger. The steam is supplied from the LNG carrier's boilers.

6.8 Forced air Circulation LNG Vaporiser

Figure 6.15: Forced air Circulation LNG Vaporiser
Source: Mitsubishi Kakoki Kaisha, Ltd. (http://www.kakoki.co.jp/english/products/)

Name. Byname. Abbreviation

Forced air circulation LNG vaporization equipment, white smoke-free LNG vaporizing equipment, non-chilled LNG vaporization equipment, LNG vaporization equipment without stand-by equipment

General Description

Unlike the conventional natural draft types that emit chill-induced white smoke to cause visual pollution (pollution by chill itself, depending on location) and unavoidably needs switching to stand-by equipment due to icing, MKKOfs closed-circulation LNG vaporization equipment using forced circulation air as the thermal medium emits no white smoke and requires no de-icing.

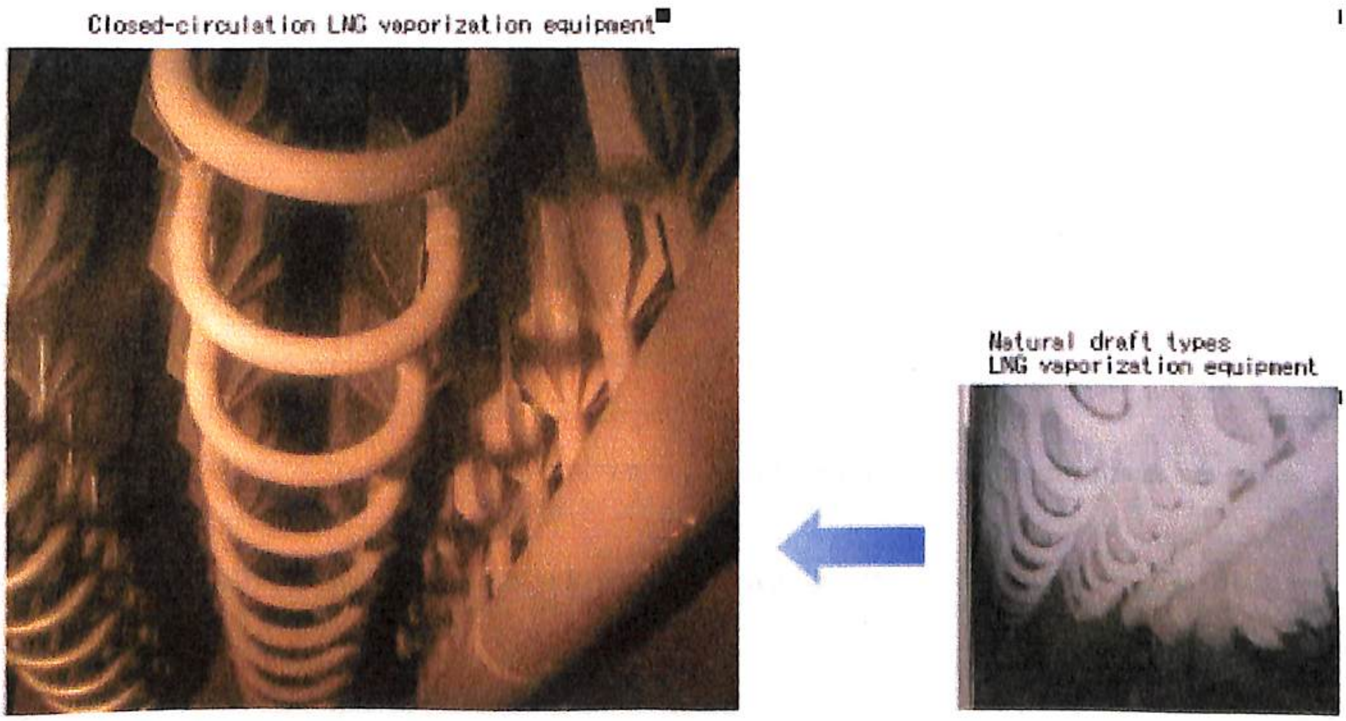


Figure 6.16: Non-White smoke effect of closed circulation LNG vaporization equipment
Source: Mitsubishi Kakoki Kaisha, Ltd.(http://www.kakoki.co.jp/english/products/)

Process Flow

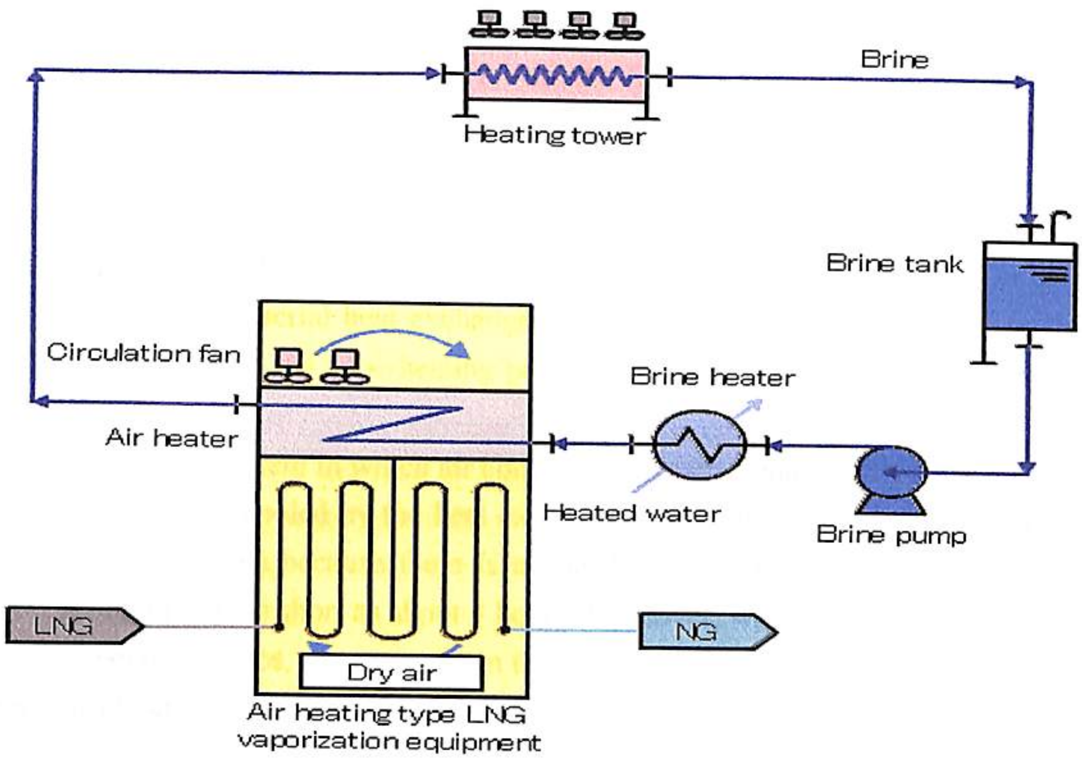


Figure 6.17: Process flow of Forced air Circulation LNG Vaporiser
Source: Mitsubishi Kakoki Kaisha, Ltd. (http://www.kakoki.co.jp/english/products/)

Features

1. No white smoke emission, thanks to closed construction and air circulation
2. Capable of continuous around-the-clock operation
3. No need for stand-by or hot-water vaporization equipment for winter use results in low initial construction cost
4. Open operation in summer results in low running cost

6.9 Natural Draft Air Fin Vaporizers (Conventional LNG Vaporizers System)

Air fin LNG vaporizers that made the atmosphere as the heat source are mainly being used in Japan for small-capacity LNG terminals, where the amount of LNG handled is relatively small. An example of the structure of an air fin LNG vaporizer is shown in Figure 6.18. This vaporizer has vertical heat exchanger tubes made from an aluminum alloy, with the fin and the pipe being formed as a single unit by extrusion molding. The heat exchanger tubes are connected to the header pipe or the bend pipe. The flow of an air fin LNG vaporizer is shown in Figure 6.19. The vaporizer consists of an evaporation part and a superheating part. There are two types of natural draft air fin vaporizer. In one, the evaporation part consists of parallel-connected heat exchanger tubes connected with the header pipe, and the superheating part consists of serial heat exchanger tubes connected with the bend pipe. In the other, both the evaporation part and the superheating part consist of serial-connected heat exchanger tubes connected with the bend pipe.

A natural draft system is a system in which air convection occurs automatically from top to bottom due to density change of the air cooled by the heat exchange with LNG. This system is currently used in small-capacity LNG terminals because there is no need for power to provide a heat source, but its continuous operation time is as short as about 4 hours. Moreover, when the air exchanges heat with the LNG, and its temperature drops, the moisture in the atmosphere condenses, producing clouds of mist, meaning that consideration must be given to the surrounding environment.

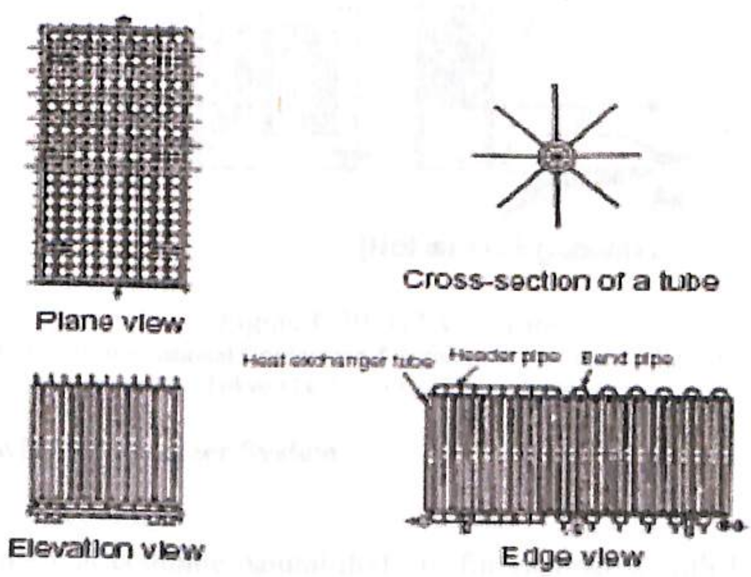


Figure 6.18: Air Fin Vaporizer

Source: Paper presented in 14th International Conference & Exhibition on Liquefied Natural Gas by Masaru Sekiguchi Tokyo Gas Co., Ltd. Tokyo, Japan

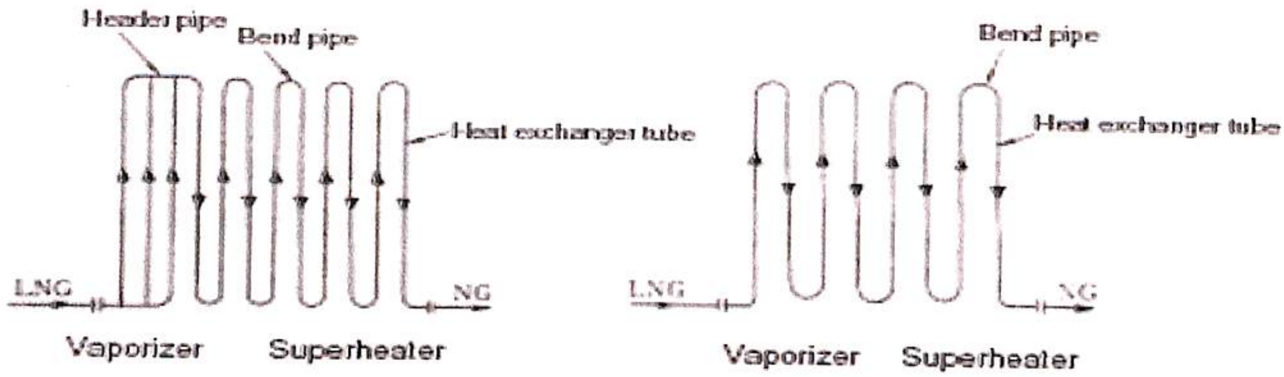


Figure 6.19: The Flow of an Air Fin Vaporizer
Source: Paper presented in 14th International Conference & Exhibition on Liquefied Natural Gas by Masaru Sekiguchi Tokyo Gas Co., Ltd. Tokyo, Japan

6.10 Hot Air Draft Super heater With Air Fin Vaporizer (Hav)

HAV Outline: - A hot air draft super heater with air fin vaporizer (HAV) system was newly devised and developed. The HAV system consists of a vaporizer, super heater, and hot air draft generator as shown in Figure 6.20. After the forced-draft vaporizer makes maximum use of the ambient atmospheric heat to vaporize the LNG (-162°C in its liquid form), an auxiliary hot air draft is produced in the super heater to boost the temperature of the gas.

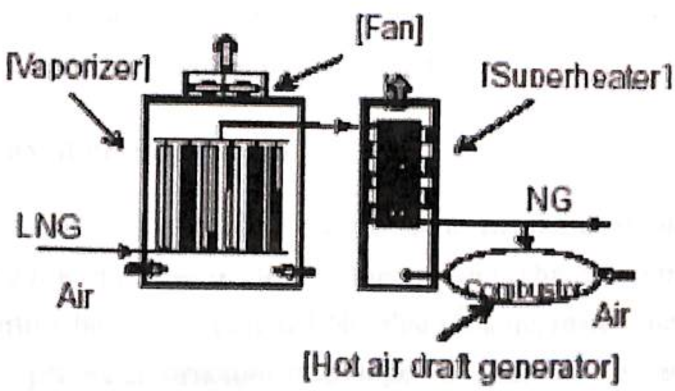


Figure 6.20: HAV Outline
Source: Paper presented in 14th International Conference & Exhibition on Liquefied Natural Gas by Masaru Sekiguchi Tokyo Gas Co., Ltd. Tokyo, Japan

6.10.1 Features of the New Vaporizer System

1) Low cost

Compared with systems that combine natural-draft air-fin vaporizers with hot water vaporizers, the HAV is a simple system that makes the maximum use of ambient atmospheric heat. Trial calculations were made for the installation of system with 1 t/h supply capacity in a cold district.

This achieves a 20% reduction in construction costs. The design also produces a remarkable 70% reduction in operating costs, due to requiring considerably less fuel as a heat source. Moreover, the installation space required for the vaporizer can be 25% smaller, and there is no need for space to install incidental facilities such as hot water boilers.

2) Use in cold regions

- ***Vaporizer:*** The fan located at the top of the vaporizer draws in large volumes of air, curbing the accumulation of frost and the resulting reduction in performance this causes. The vaporizer also features newly redesigned air fin tubes with large surface areas for heat exchange.
- ***Superheater:*** To ensure that the gas absorbs the heat of the hot air draft with minimum waste, the gas and hot air flow in opposite directions, and tubes with a large number of circular fins are used.
- ***Hot air draft generator***: When the ambient temperature drops, the temperature of the hot air draft can be raised to maintain the vaporized town gas above the minimum allowable temperature requirements for the downstream piping material.
- ***Defrosting:*** Defrosting can normally be carried out by forced ventilation using fans, doing away with the need for sprinkler-based defrosting systems. In mid-winter, heat from the hot air draft can be used to augment normal defrosting measures.

3) Calorific value stability of production gas

- ***Startup***: When one line is stopped due to a change in gas demand during today, overheated gas from the operating line is connected to the stopped line. This setup prevents calorific value fluctuation on starting because it purges LNG that remains inside the vaporizer.
- ***Operation:*** The superheater structure is arranged so that flow is on the level or descending in order to prevent fluctuation in calorific value due to retention of fluid in the system and consequent evaporation of high calorific value components if non-evaporated LNG enters the superheater.

4) Mist prevention

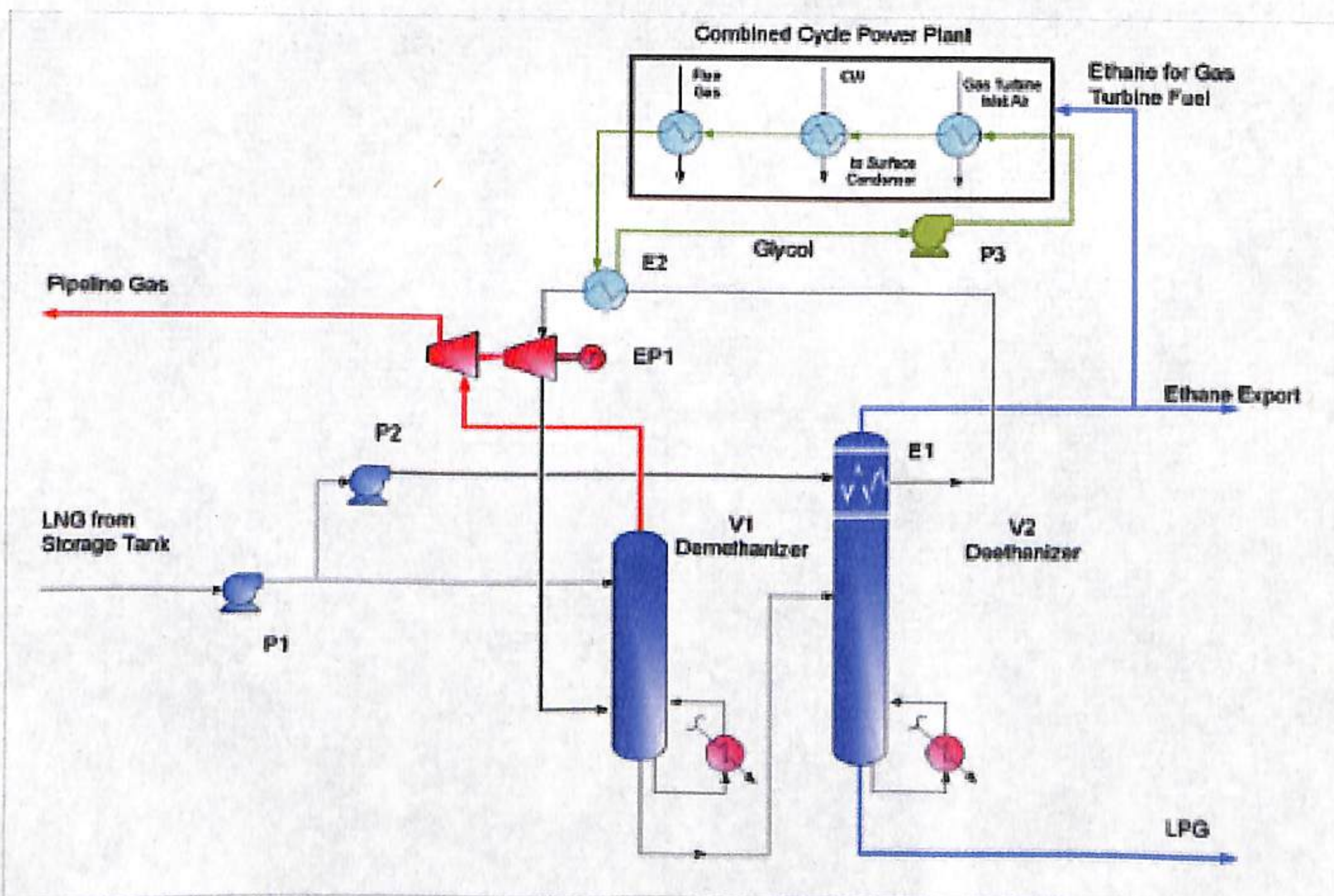
- Problems with clouds of mist, arising in conventional air fin vaporizers from condensation of atmospheric water vapor, are resolved in the HAV by the fan on top of the vaporizer, which disperses the water vapor before it can condense.

5) High reliability

- The HAV uses aluminum alloy, well known for its excellent performance and durability at low temperatures, as the heat exchange material.
- The fan and hot air draft generator are based on general-purpose products, the durability of which has been proven by performance. We have also established a speedy maintenance service.

Chapter- 7

Integrated LNG Re-gasification Processes



Integrated LNG Re-gasification Processes

The new LNG re-gasification process integrates the vaporisation process with a power plant to maximise overall power efficiency. The process includes the following features:

- Power generation with LNG utilised as a working fluid.
- Integration with a power plant to improve power generation efficiency.
- Production of a lean gas, ethane, and propane plus liquids.

The conceptual design is shown in Figure 7.1 the design is based on a LNG sendout rate of 1200 MMSCFD with the composition shown in Table 7.1.

Components Mol fraction	LNG feed	Ethane	LPG	Pipeline gas
N_2	0.0065	0.0000	0.0000	0.0073
C_1	0.8516	0.0178	0.0000	0.9878
C_2	0.0522	0.9728	0.0023	0.0042
C_3	0.0228	0.0092	0.5407	0.0003
IC_4	0.0071	0.0000	0.1200	0.0000
NC_4	0.0107	0.0000	0.1918	0.0000
IC_5	0.0040	0.0000	0.0573	0.0000
NC_5	0.0020	0.0000	0.0337	0.0000
C_{6+}	0.0030	0.0000	0.0505	0.0000
Heat value Btu/ft³ (HHV)	1158	1750	2585	999
MMSCFD	1200	60	70	1070
bpd		37 700	51 200	

Table: 7.1: Overall balance of the integrated LNG Facilities

(Source: Paper presented by J. Mak, D. Nielsen, D. Schulte, and C. Graham, Fluor Enterprises Inc., *on* **L N G Flexibility)**

The overall mass balance for a 1200 MMSCFD Integrated LNG Regasification Facility is shown in Table 2. This facility produces 37 700 bpd of ethane, 51 200 bpd of LPG, and 1070 MMscfd of 999 Btu/ft3 HHV pipeline gas. The process depicted in Figure 1 consists of two integrated cycles: a LNG power cycle where LNG is used as a working fluid to produce power and another parallel cycle where the LNG is used to improve the power generation efficiency of a combined cycle power plant.

7.1 LNG power cycle

In Figure 7.1, LNG from storage is pressurised by LNG pump P1 to approximately 500 psig. Approximately 50% of this LNG (5000 GPM) is sent to the demethaniser as column reflux. The LNG power cycle pump P2 pumps the remaining LNG to approximately 2000 psig. This high pressure LNG is used as a working fluid to recover low-level heat from the power plant flue gas for power generation.

The high pressure LNG from P2 is heated in two heat exchangers, E1 and E2. The reflux condenser E1 in the deethaniser overhead increases the LNG temperature to approximately -190 °F. Using the LNG to satisfy the fractionation process refrigeration requirement, eliminates a costly propane refrigeration system.

The LNG leaving the reflux condenser is heated to approximately 300 °F and vaporised in glycol/water exchanger E2 using waste heat from the power plant flue gas. A glycol/water heat medium is used to transfer heat between the power block and the LNG regasification facility. This indirect heat exchange system isolates the LNG from direct heat exchange with the power block. A backup heat source can use this heat transfer fluid to vaporise the LNG if the power plant is not in operation. Possible backup heat sources include a fired heater or duct firing on the waste heat recovery units.

The hot LNG vapor is then expanded in expander EP1 to produce power. The low temperature of the LNG working fluid achieves more efficient power production from the power plant's low level waste heat than a steam cycle.

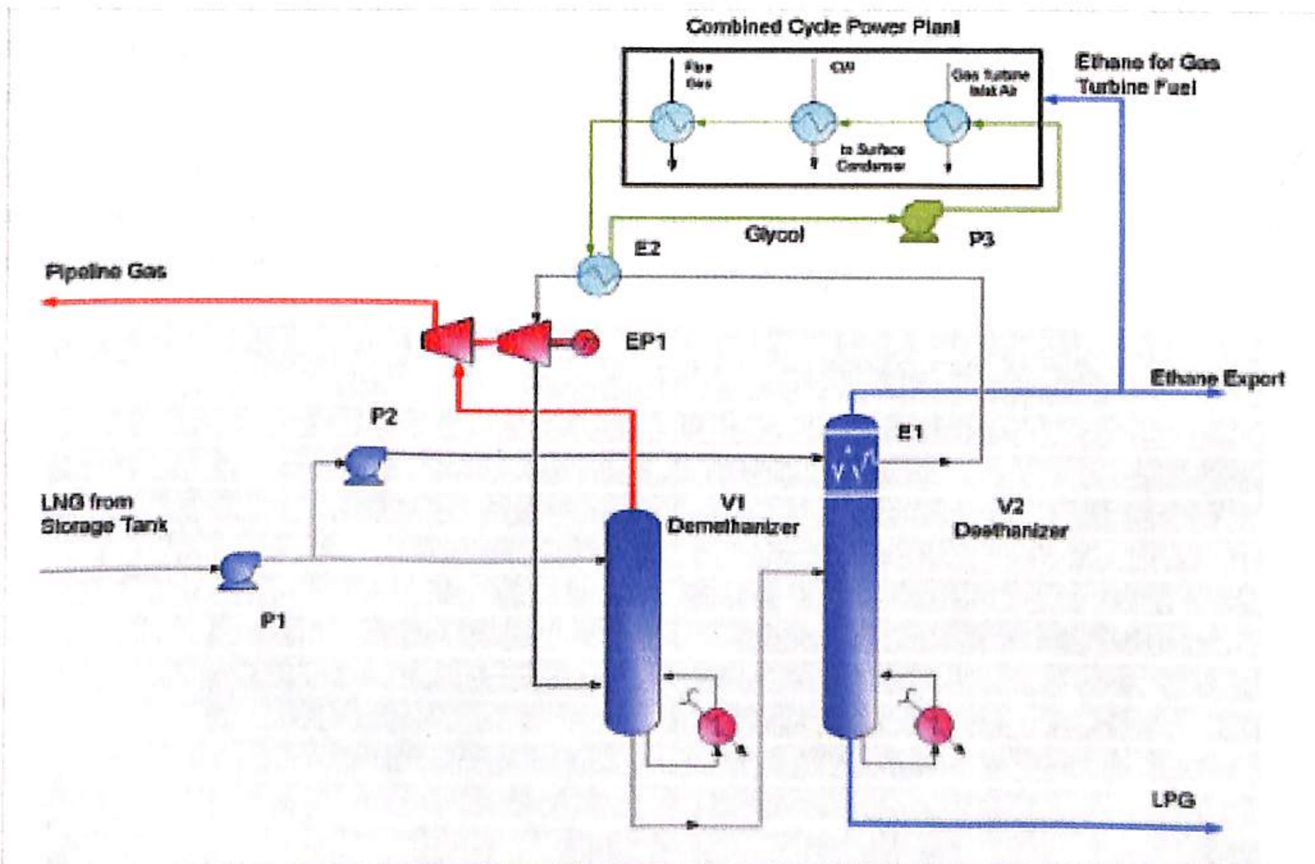


Figure 7.1: Integrated LNG Regasification Facilities

Source: Paper presented by J. Mak,D. Nielsen,D. Schulte, and C. Graham, Fluor Enterprises Inc., on **L N G Flexibility**

Approximately 27.6 MW is generated when the high pressure, high temperature LNG vapor is expanded into the demethaniser. In the region of 60% of this power is used by the residue gas compressor to compress the demethaniser overhead from 440 psig to the pipeline pressure of 1100 psig. The excess 11.0 MW can be used to generate electricity for internal use or for export.

7.2 LNG cold utilization increases power plant output

In addition to the LNG power cycle, the LNG is also used as a heat sink to improve power generation efficiency. Per Figure 1, the LNG cools a glycol/ water solution in exchanger E2 to produce a chilled glycol/ water stream that is circulated back to the power plant. This chilled glycol/water is used in a chiller coil at the gas turbine inlet to cool the inlet air. The colder air temperature allows higher mass flow through the gas turbine, resulting in higher gas turbine power output and efficiency. Figure 7.2 shows the impact of ambient air temperature on power generation for a Frame 7 based combined cycle power plant. Gas turbine inlet air-cooling decouples power generation capacity from changes in ambient temperature. Conventional power plants experience a drop in power output when ambient temperatures rise. In many cases this drop in power output occurs when power demand peaks and can be sold for a premium. With gas turbine inlet air-cooling, power output and generation efficiency can be maintained at optimum levels throughout the year, dramatically improving power plant economics.

Unutilised chilled glycol/water can also be used to reduce the power plant cooling water supply temperature. This will lower the steam turbine surface condenser pressure and provide a lower condensing steam turbine backpressure and thus more power output.

LNG Regasification	Non-integrated facilities	Integrated facility
Seawater flow rate, GPM	100000	None
LNG pumps, MW	8.2	6.5
Seawater pumps, MW	5.2	None
Net expander output, MW	None	-11.6
Net power consumption, MW	13.4	-3.1
Power plant		
Combustion air inlet, °F	75	40
Power plant, MW	487.8	538.3
Fuel, million Btu/hr LHV	3095	3372
Net power output, MW	474.4	541.4
Power generation efficiency, Btu/kWhr	6524	6227

Table 7.2: compression of the integrated facilities with non-integrate facilities

Source: Paper presented by J. Mak,D. Nielsen,D. Schulte, and C. Graham, Fluor Enterprises Inc., on **L N G *Flexibility***

7.3 LNG Fractionation

LNG fractionation is performed in a demethaniser that is capable of recovering up to 99% of the propane and over 90% of the ethane in the LNG. Per Figure 7.1, approximately 5000 GPM of LNG reflux is used to maintain the demethaniser overhead at approximately -130 °F. The expander discharge vapour, acting as a stripping vapour, is fed to the mid section of the demethaniser, and the remaining stripping duty is supplied by the bottom reboiler. The glycol/water heating system is used to maintain the demethaniser bottoms temperature at 130 °F to minimise the methane content of the ethane product.

If desired, the process can be operated to meet a wide range of ethane recovery levels while maintaining propane recovery above 95%. Lower ethane recovery requires less reflux to the demethaniser, but more reboiler duty. This can be accomplished by changing the LNG feed split ratio to reduce the LNG reflux to the demethaniser. For example, in order to operate at 50% ethane recovery, the demethaniser reflux rate must be reduced from 5000 GPM to approximately 4500 GPM. This increases the LNG flow to the expander by 500 GPM, resulting in a 10% increase in expander power output. The higher expander flow will also supply more stripping vapour to the demethaniser, compensating for the higher reboiler requirement.

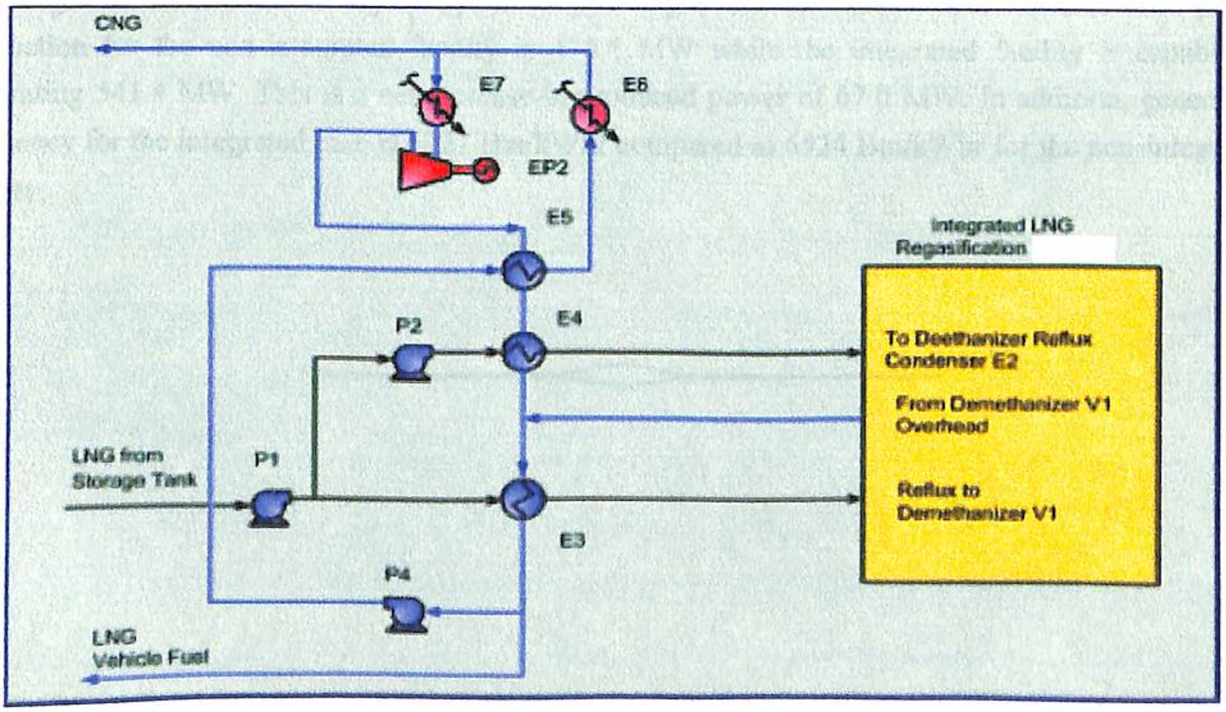


Figure 7.2: Integrated Regasification facility, LNG and CNG Production

Source: Paper presented by J. Mak,D. Nielsen,D. Schulte, and C. Graham, Fluor Enterprises Inc., on **L N G Flexibility**

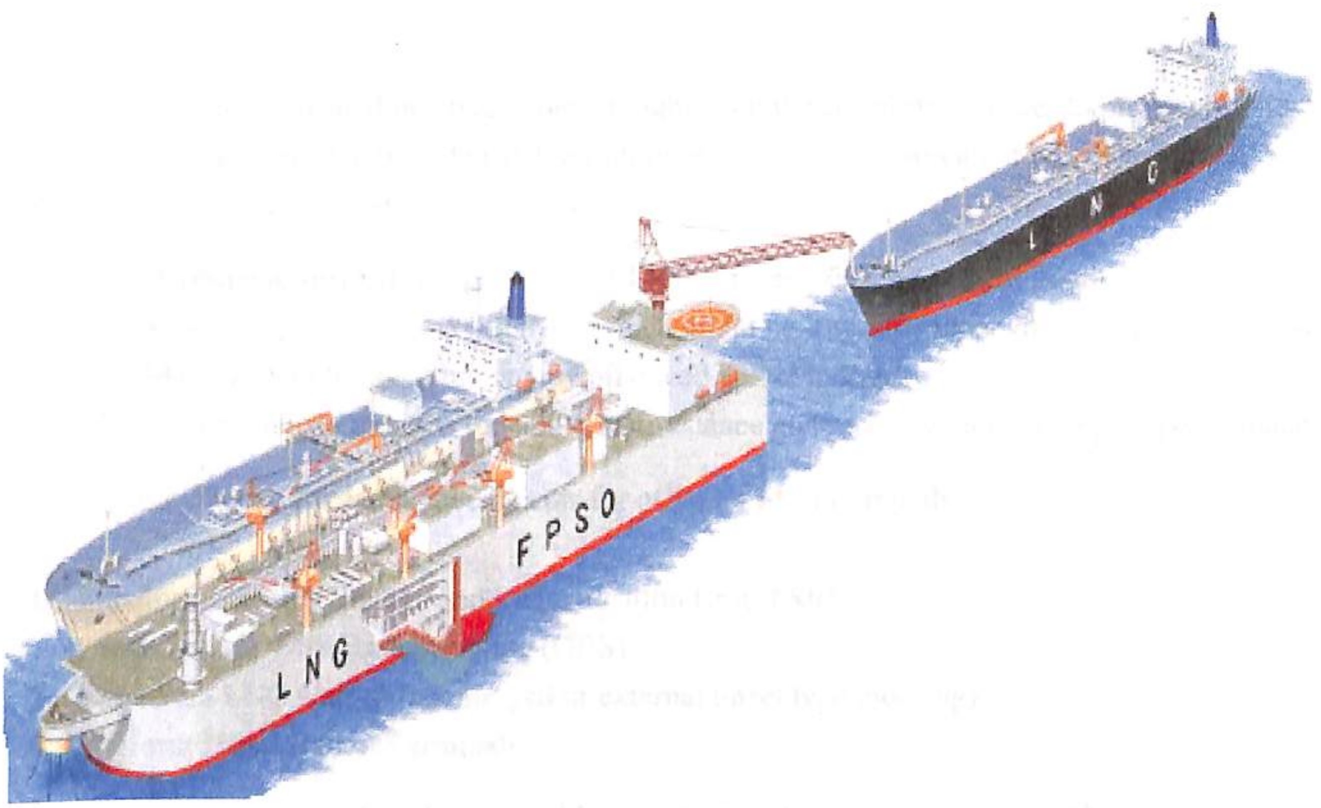
The demethaniser bottoms liquid is fractionated in a deethaniser, into an ethane overhead and a propane plus bottoms product. The deethaniser V2 typically operates at approximately 400 psig, with an overhead temperature of 45 °F. The deethaniser bottoms temperature is maintained at approximately 220 °F, to control the vapour pressure of the LPG product. The deethaniser overhead vapour can be fed directly to the gas turbines as fuel. This may be necessary if there is a limited market for ethane. If all of the ethane product can be sold, the deethaniser can operate at a lower pressure, reducing energy consumption and capital cost.

7.4 Integrated vs. non-integrated

A seawater heating system is not required in the integrated facility, as it uses waste heat from the power plant for LNG regasification. Therefore, the 100 000 GPM seawater system, and the seawater intake and outfall infrastructure required by a conventional regasification unit can be eliminated. This also saves in the region of 5.2 MW of power required by the seawater pumps. However, the power required by the LNG pumps for the integrated facility is slightly higher. This is due to the extra power consumed by the LNG power cycle pump P2. The net power production from the LNG expander cycle, after residue gas compression, is 11.6 MW. In summary, the non-integrated facility consumes 13.4 MW while the integrated facility generates 3.1 MW. Utilisation of LNG as a power plant heat sink in the integrated facility has a major impact on power generation. The net result is that total power production for the non-integrated facility is 474.4 MW while the integrated facility is capable of generating 541.4 MW. This is a net increase in produced power of 67.0 MW. In addition, generating efficiency for the integrated case is 6227 Btu/kWhr compared to 6524 Btu/kWhr for the non-integrated facility.

Chapter- 8

Non-Traditional Concepts for Receiving and Regasification of LNG



Chapter-8

Non-Traditional Concepts for Receiving and Regasification of LNG

8.1 Introduction

There is a need for increased LNG transport to support the fast growing demand of LNG. Until now only onshore import terminals have been built for receiving LNG, storage of LNG, regasification to natural gas (NG) and send-out of NG. Preferably these terminals are located close to densely populated areas, where the majority of consumers of this type of energy are found.

However, public opinion in several countries is getting more and more opposed against onshore LNG terminals, considering perceived safety risks and/or visual pollution of surroundings. Furthermore governmental issues like permits, environmental impact studies, etc. may significantly slow down the progress of new onshore LNG terminal projects.

Therefore the alternative of offshore LNG import terminals has been proposed. Such facilities should fulfill some important constraints:

- They should be located practically out-of-sight from the coastline, in order to prevent public concern regarding safety and visual pollution of horizon - The so-called NIMBY attitude
- They should have a high operability with regard to:

    1. Berthing & offloading operations of LNG Carriers, depends on environmental conditions
    2. Processing of stored LNG to NG, which might be impacted by environmental conditions like seawater temperature or wave-induced vessel motions
    3. Redundancy of systems (enabling maintenance and repair without decreased performance)

There are basically two fundamental concepts for offshore LNG terminals:

1. Floating: Floating Storage and Regasification Unit (FSRU)
2. On seabed: Gravity Base Structure (GBS)
3. Converted LNG Carrier (submerged or external turret type mooring)
4. Platform Based Import Terminals

This concept-screening methodology provides a structured mechanism for combining commercial market, local site and permitting conditions to logically rank the various alternatives against their respective costs.

This approach has already proven invaluable to ensure selection of the right terminal concept in an early project development phase, avoiding regret time and expenditure by focusing quickly on the right concept taking all essential multi discipline parameters into account. In addition it allows stakeholders a transparent and quantified insight into the decision making process, a vital step in today's complex permitting climate.

8.2 Loading, Storage and Regasification Unit (FSRU)

A Floating Storage and Regasification Unit (FSRU) LNG import terminal concept comprises of a purpose built permanently moored FSRU with several LNG carriers shuttling between the export facility and the import site. The FSRU barge is typically between 350 to 400 metres long by up to 70 metres wide and normally does not have a propulsion system. (It will be towed from the shipyard and installed at its operational site.)

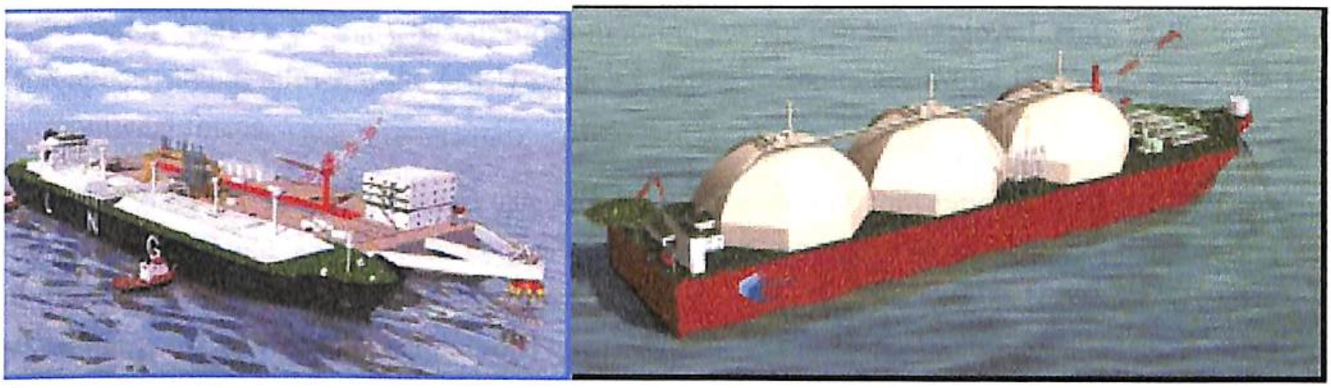


Figure 8.1: Artist Illustration of FSRU
(Source: Excelerate Energy, **Offshore Liquefied Natural Gas Overview, Public** Symposium on LNG Brunswick, Maine)

The FSRU consists of a double-hulled barge designed using normal shipbuilding designs and standards and can be constructed in a wide range of conventional ship yards worldwide (although typically these are based in Far East). The LNG storage system is based on standard designs for ship cargo containment systems; using spherical tanks, membrane or prismatic freestanding tanks. (Storage capacity can range from around 200,000 m^3 to in excess of 500,000 m^3 as required.

The regasification facilities are located on the main deck of the barge and are typically tailored to suit the specified gas send-out conditions. Power generations for barge services are normally provided by gas turbines with dual fuel diesel engines as back up (sized according to the requirements of the regas equipment). Accommodation is generally located at the stern (unlike in the artist's impression shown above) so as to provide the maximum distance between the turret and accommodation unit.)

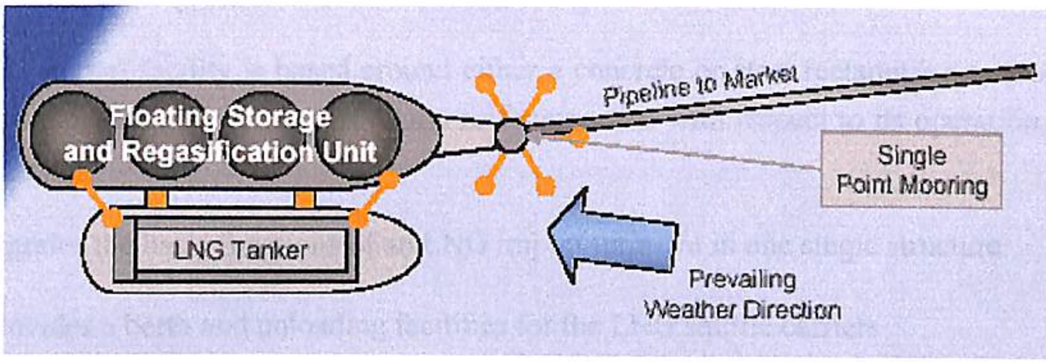


Figure 8.2: Bird eye view of FSRU
(Source: Excelerate Energy, **Offshore Liquefied Natural Gas Overview, Public** Symposium on LNG Brunswick, Maine)

A key advantage of the FSRU concept is that it can be moored in a wide range of water depths. In shallow waters (approximately 20 to 30 meters), a jacket based, soft yoke system can be used, in greater water depths a catenary based; turret-mooring system can be employed. Both of these systems are weather-vaning, allowing the FSRU barge's heading to rotate according to the vector of the local environmental forces.

LNG offloading is typically achieved using a modified version of conventional hard arm LNG loading arms. In this so called `side by side' configuration the LNG carrier is moored alongside the FSRU with both vessels weather vaning around the FSRU's turret mooring. This system is limited to a relatively benign range of environmental conditions governed principally by the combined relative motion of the two vessels and the operational limit of the tugs used to assist berthing operations. In the event the FSRU is required to be located in harsher metocean conditions then use of an alternative offloading technology called `Stern to Bow' or `Tandem' configuration can be made. Whilst this tandem technology is still considered developmental several leading industry equipment suppliers are actively progressing it.

So the FSRU is typically a turret-moored barge with a steel hull that contains the LNG storage tanks. Regasification modules are installed on the deck and gas is sent out via a riser and a subsea pipeline to the customer.

8.3 Offshore Gravity Based Structures (GBS)

A GBS LNG import facility is based around either a concrete or steel rectangular caisson (or several caissons) located on the seabed and is totally self-supportive with respect to its operation, utilities and power generation.

A GBS integrates the basic functions of an LNG import terminal in one single structure:

- It provides a berth and unloading facilities for the LNG shuttle carriers
- It contains the space for LNG storage
- It houses the regasification, utility and sendout equipment on its deck

Additionally, the GBS provides protection of the LNG carrier against excessive waves and current during the offloading and berthing operations.

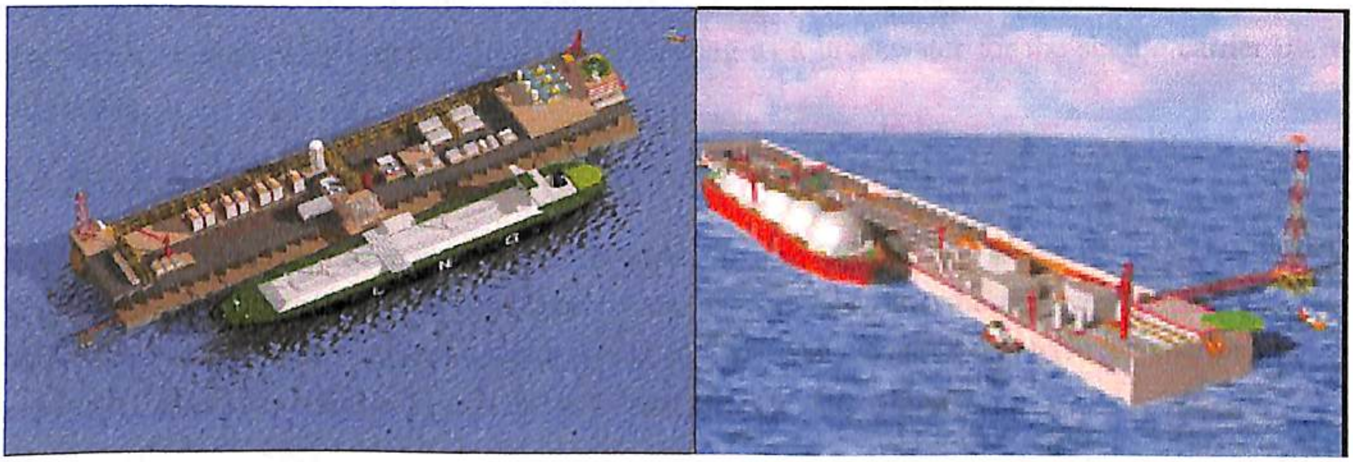


Figure 8.3: Typical LNG import Gravity Base Structure (GBS)
(Source: Excelerate Energy, **Offshore Liquefied Natural Gas Overview, Public** Symposium on LNG Brunswick, Maine)

The GBS typically requires a location in modest water-depths, since the larger the water depth, the higher the structure needs to be and the higher the costs. The minimum required water depth for a GBS is typically 14 - 15 meters, governed by the depth required for an LNG carrier to be able to approach and berth to the terminal.

Typical overall dimensions of a GBS with 250,000 m3 LNG storage capacity, located in 15 meters of water, are approximately 340m long by 60m wide by 40m high. Located on top of the GBS deck, along with all the regasification equipment and utilities, will also be the accommodation, flare and a heli-deck, in line with governing safety requirements for offshore structures.

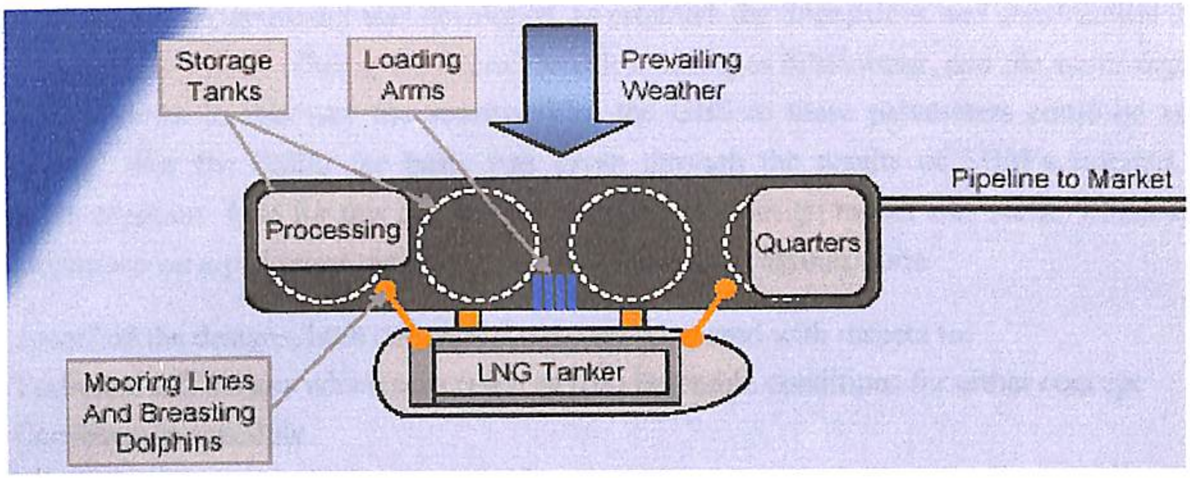


Figure 8.4: Bird Eye view of LNG import Gravity Base Structure (GBS)
(Source: Excelerate Energy, **Offshore Liquefied Natural Gas Overview, Public** Symposium on LNG Brunswick, Maine)

So the GBS is typically a pre-stressed concrete caisson with sufficient ballast compartments to lower it down to a stable position on the seabed. The caisson contains the LNG storage tanks and has regasification equipment installed on top, while acting as a breakwater for the shuttle carrier during offloading.

8.4 A comparison study between (FSRU) and (GBS)

A comparison study has been carried out between Floating Storage and Regasification Unit (FSRU) and Gravity Base Structure (GBS) to quantify the aspects regarding the relative competitiveness of both concepts. This paper addresses under which conditions one concept can have advantages over the other one. There to the following aspects have been taken into account.

- Technical issues
- Construction schedule "first-gas-to-customer"
- The sensitivity to location parameters.
- The initial investment and life cycle cost.

8.4.1 Study approach

For each concept a design has been developed, based on the assumption that the conditions for each concept are optimal, hence to arrive at the most competitive design for each concept. Both concepts have been designed for the same gas storage volume and send-out capacity. For this comparison study a benign environment was selected, with occasional heavy storms.

For the GBS first a design model was developed, to establish the dimensions and construction costs as function of main parameters (being the overall length L acting as breakwater, and the water depth WD at the site location). In this way the sensitivity of the GBS to these parameters could be assessed quantitatively. For the FSRU the basis was given through the results of SBM's internal FSRU development program. Also for this concept a translation to a design model was made, which allowed a cost comparison on equal terms, using the same cost basis and assumptions.

Having specified the designs, both concepts were then compared with respect to:

1. Technical differences which may result in (un) favorable conditions for either concept
2. Construction schedule
3. Relative cost sensitivity to site-specific parameters, such as water depth, distance to shore, wave height, soil conditions, weather directionality, and location of construction site or shipyard.

An absolute cost comparison is not given in this paper, although the comparison study included the calculation of capital investment costs (CAPEX), operational costs (OPEX), and overall life cycle costs (LCC). The reason that these costs are not directly quantitatively compared is that the comparison was based on optimal design conditions for each case, which results for both concepts in the lowest possible cost. However, since the concepts differ fundamentally (floating vs. gravity-based, weathervaning vs. fixed orientation, entirely different construction and installation methods), an optimal condition for one concept nearly automatically results in unfavorable conditions for the other concept.

As a general comment it can be stated that the FSRU has a lower cost for the optimized conditions relative to the GBS, both on CAPEX as on LCC. It was therefore decided to concentrate on the technical differences, construction time, and on sensitivity to location-specific conditions. This type of comparison will generally point into a direction of the most attractive concept for the chosen conditions

In more detail, the following aspects were taken into account for the life cycle cost estimate:

- Building site development (GBS)
  - Graving dock (GBS)
- Construction phase
  - Fabrication of hull and containment system
  - Tank installation method in hull (FSRU)
  - Topsides installation
  - Pipeline to shore

- Transport and installation phase
    - Tow to site
    - Channel dredging (GBS)
    - Sinking and stabilizing (GBS)
    - Anchoring and hook-up (FSRU)
- Operational phase
    - Berthing and mooring (tugs etc.)
    - Maintenance and inspection
    - Fuel
    - Personnel
- Decommissioning phase (not included in costs)

Finally, the flexibility and risks of both concepts were qualitatively compared.

8.4.2 Design basis: -

This paragraph lists the main design parameters that are used for both concepts. They are the same where possible, but differences occur mainly in the chosen water depth and corresponding wave heights.

Capacity: - The chosen capacity of both concepts is as follows:

Storage capacity	250,000 m^3
Regasification	6.3 MTPA
Gas send-out rate	720 ton/h (normal)
Supply by LNGC	138,000 m^3
Offloading rate	10,000 m^3/h

Environment: - The 100-year storm conditions are as follows:

	GBS	FSRU
Storm condition Hs	6.9 m	9.6 m
Wave period Tp	13 s	13 s
Current: surge & tide	1.1 m/s	1.1 m/s
Wind speed 1-hour avg.	41 m/s	41 m/s

These data are used to check the design of the GBS (stable foundation on soil during storm condition), and the FSRU (strength & excursions of the mooring system).

For every-day operations, additional environmental data are used as follows:

- The probability that the following environmental conditions are not exceeded is 95%: Hs = 2 m,
- The probability that the following environmental conditions are not exceeded is 99 %: Hs = 2.8 m.

These two non-exceedance probabilities provide input for the determination of downtime. The significant wave height of 2 - 3 m is generally regarded as an upper limit for tugs providing assistance in berthing of the LNGC next to the terminal (either GBS or FSRU).

Bathymetry and water depth: - For the FSRU a design water depth of 40 m is taken. The GBS can be located in shallow water, which is advantageous for its construction costs. The smallest feasible water depth has been calculated as follows:

- LNGC draft laden	11.5 m
- Minimum keel clearance	2.0 m
- Allowance for siltation	1.0 m
- LNGC max. heave motion	0.5 m
- Safety for LNGC motions	1.0 m
- Minimum required water depth	16.0 m LAT

General assumptions: -

- Lifetime 25 years operation
- Distance to shore: 10 nm (18.5 km)

GBS assumptions: -

- Suitable nearby location for graving dock available, with favorable soil conditions (low water ingress rate), Sea bottom: sand, nearly flat (< 1 % slope).
- Sea bottom slope near graving dock: 0. 5o.

FSRU assumptions: -

- Fabrication and topsides integration in East Asia.
- Sufficient water depth at assumed distance from shore.

8.4.3 Experimental

GBS description: - The GBS is a rectangular structure for ease of construction (this applies both to the concrete work as well as to the membrane containment system inside). Furthermore, a rectangular structure can provide a large length, acting as a breakwater for the moored LNGC's.

The large length is combined with a restricted width, to reduce the span of the transverse beams supporting the main deck and topsides weight.

A sketch of the chosen layout and internal cross-section is shown in fig. 1. It has a concrete double bottom and concrete double walls all around, providing safety of the structure against boat impact, as well as space for ballasting of the GBS, in respect of sufficient foundation on the sea bottom.

Two large tanks provide storage for LNG. Although some designs show only one storage tank, the chosen concept is based on two tanks, to ensure a certain degree of redundancy in case one tank has to be repaired therefore (however remote the chance of repair is, the consequences of shutting down the whole terminal in respect to the LNG supply chain cannot be tolerated).

Double skin spaces with double bottom and strengthened with ribs divides the compartments. Furthermore, skirts are provided underneath the base slab. A minimum skirt height of 2 m is always applied, in order to prevent rapid erosion of the soil underneath the bottom slab, by the action of waves, current and tide. A skirt height of more than the minimum 2 m might be necessary for stable foundation on the sea bottom (soil sliding criterion). Due to the skirts, the draft during tow will be increased. This can be partially offset by pumping air underneath the base slab, which will be trapped between the skirts.

All installations (topsides systems, accommodation) are fitted on the main deck. Due to the large area L*B of this deck, and the high L/B aspect ratio there is no design problem for a proper arrangement of the topsides in view of functionality and safety. This aspect is therefore disregarded in the comparison study, as the FSRU also has sufficient main deck area available.

The accommodation is assumed for an operating crew of 30 people (maximum persons of 50). The GBS should be positioned perpendicular to the daily waves and wind conditions, in order to provide an optimal breakwater function. This requirement implies that there should be a predominant daily wind & waves direction: e.g. from the south, with sectors to southwest and southeast of not more than 45o. Furthermore, the current should be predominantly parallel to the GBS length direction, in order to have the LNGC's facing the current during berthing.

FSRU description: - The hull design is driven mainly by the containment system for the LNG. For the FSRU the consideration of partial filling of the cargo tanks in combination with vessel's motions is of paramount importance in the choice of the containment system.

At present, the membrane-type containment system requires further investigation to demonstrate its suitability for partial loading in harsh environments. Spherical tanks can be used but their application either results in larger FSRU main dimensions, or it requires a new type large-diameter tank. Extra deck space is required for the regasification plant. The IHI-SPB type tanks have inherent anti-sloshing behavior due to the fact of its internal structure of swash bulkheads; stiffeners and horizontal stringers dampen the sloshing motion. Furthermore, the construction of the SPB tanks is standard shipbuilding practice (stiffened plate panels), and makes it possible to construct the tanks in accordance with standard shipbuilding practices.

In view of the above considerations, the IHI-SPB (Self-supporting Prismatic IMO type B) tanks have been chosen for the base-case FSRU. It should be noted, however, that if the environmental conditions permit, of if commercial considerations favor another system, there should be no reason why they could not be applied as well. The layout of the FSRU is shown in Figure 13.2. The cargo storage area is the main part of the FSRU. The LNG tanks are located within a double hull (double shell and double bottom). There are 5 storage tanks, separated by transverse bulkheads.

The cargo area is separated from the forward compartments and the aft peak by a cofferdam. Aft of the storage area is the aft peak, which has a double function:

- LNG tanks in case of collision
- Provide space for the thrusters, which are used in assisting the weathervaning capability, especially during side-by-side offloading of a LNGC

Forward of the storage area are three main compartments separated by transverse bulkheads:

- A compartment for the internal turret system
- A compartment housing the engine room and the accommodation block on top
- The forepeak, with the helicopter deck on top

The large main deck on top of the cargo area provides sufficient space for proper layout of the topsides. The process vent stack of the topsides systems is located well aft, so the wind blows the vented gas away from the FSRU and the side-by-side moored LNGC. In accordance with the IGC code each LNG storage tank also has its own independent emergency vent post. Due to the large required height, all vents are supported by prismatic shaped tower structures, made from cryogenic-resistant steel. The accommodation is assumed for an operating crew of 32 people (two more than on GBS, to operate and maintain the active ballast system, which is always in use).

The ratio's B/D and L/B (and implicitly L/D) are taken in accordance with naval architectural practice. This has resulted in the following main dimensions:

- L∞ 336.3 m, - B 59.4 m, - D 32.4 m, - T 11.0 m

8.4.4 Technical comparison between GBS-FSRU

For the technical comparison the various functions of the offshore import terminal are taken as starting point. The following points have been reviewed; Design phase, Construction phase, Operational phase and Future Phase.

1) Design phase: - For the design phase the main differences between both concepts lie in the permitting and site selection. These are described below.

Permitting:- The application for a permit involves describing the project and alternative solutions, mitigating measures for e.g. emissions, and spills, an environmental impact assessment (EIA), and demonstration of compliance with regulations and federal authorizations. It is believed that both concepts are equally suitable to obtain a permit from the regulatory authorities.

Site selection: -. The GBS should ideally be located in water depths less than 20 m. A larger depth will add to the cost, and will make its construction and installation more challenging. For a larger water depth, the GBS itself needs to be higher, the graving dock needs to be deeper and the dredged channel into sufficiently deep water longer. For the FSRU the site selection is less critical. The FSRU may be located anywhere where the water depth is sufficient to moor the unit safely. In this respect the conclusion is that the FSRU can be more flexibly deployed, compared to the GBS.

2) Construction phase: - During the construction both concepts differ in many respects. The main differences are discussed below.

Construction site: - For the GBS construction a graving dock must be developed, as described earlier in this paper. Alternatively, an existing graving dock may be found, but it is likely that extra costs are required to make it suitable for the construction of the GBS. Permitting may cause extra delays. The FSRU will be built in a shipyard, according to standard shipbuilding practices. It is concluded that It is concluded that construction risks and cost escalation can be better controlled for the FSRU.

Fabrication: - Provided that a suitable graving dock location is available, the GBS can be built in the vicinity of the installation location. The FSRU will likely be fabricated in East Asia, for cost reasons. The construction of the hull is in accordance with standard shipbuilding practices.

For both concepts, the topsides are assumed to be installed by floating sheerleg-type cranes once GBS or FSRU hull are afloat. Once the graving dock for the GBS is available, both concepts are considered equally straightforward to fabricate.

Topsides integration: - For the purpose of the study it was assumed that topsides would be pre-fabricated in modules. It is therefore considered that there are no major differences between both concepts related to topsides installation and integration. Overall, both concepts are considered equal in this respect.

Transport: - Unlike a ship-shape hull, a GBS is normally not designed for sea transport over long distances, e.g. for a 1-year storm condition. The GBS is a simple rectangular block with skirts underneath it. It has therefore very poor sailing properties The FSRU is designed for a long-distance tow from East Asia to its installation site. Technically the transport of the FSRU is much more flexible that that of the GBS.

Site preparation: - For the GBS installation location, the seabed must be flat, and any silt and mud must be dredged away until a stable soil foundation is obtained. For the FSRU installation location, site preparation is generally not necessary. It is therefore concluded that this aspect is an advantage for the FSRU.

Installation: - Installation of the GBS is a much more tedious and critical operation than for the FSRU. Particularly the lowering and leveling operations are critical. Installation of the FSRU involves the hook-up to the pre-installed mooring lines and piles, tensioning of the lines, and the hook-up of the pre-installed risers to the turret. It is therefore concluded that the installation of the FSRU is easier and less risky.

Schedule:- The shortest schedule for the GBS is approximately 6-7 months longer than that for the FSRU, due to the time required to develop the graving dock. Bearing special circumstances it is therefore concluded that the FSRU has a clear schedule advantage over the GBS.

Cost escalation:- Although the costs of both concepts were evaluated in the comparison study, it is not felt appropriate to directly compare both concepts, since they differ too much in nature to compare on a fair basis for a given location. Depending on the location parameters, one of the concepts would obviously have the cost advantage over the other one. Qualitatively it can be stated however, that being the conditions optimal for both concepts the FSRU has a lower CAPEX and LCC. The OPEX of both concepts is comparable.

It is nevertheless more appropriate to analyze under which conditions each concept has the best performance, or when it is particularly unattractive. From the sensitivity analysis it appeared that the GBS is quite sensitive to a number of location parameters, which can lead to a significant increase in cost, compared with the most optimal conditions. Therefore the GBS has a significant upward cost escalation risk due to site-specific parameters.

3) Operational phase. During the operational phase the differences lie mainly in the fact that the GBS is a fixed concrete installation, whereas the FSRU is a floating steel hull type installation.

Berthing and mooring: - In unprotected open sea, the FSRU will have a higher operability than the GBS due to its weathervaning capability, which is easier for the LNGC to approach and moor. The FSRU will also need fewer tugs to assist the carrier during its approach and mooring. The FSRU is fitted with thrusters capable of adjusting its orientation to facilitate the berthing operation. It is therefore expected that the LNGC can berth and moor in higher sea states to the FSRU.

LNG transfer: - The offloading of LNG from the carrier to the import terminal in a side-by-side arrangement is probably easier for the FSRU than for the GBS. The offloading will be possible in higher sea states for the FSRU than for the GBS, due to higher mooring limits. For the GBS the limits are roughly 1.5 m for berthing, and 1.5 – 2.5 m for the moored condition offloading, depending on the wave period.

For the FSRU the expected berthing and moored condition limits are approx. 2.5 m, but also depend on the wave period. Further study will be required to assess the relative differences between both concepts regarding LNG offloading, depending on the local environment.

Storage: - There are no significant (dis) advantage between both concepts as far as storage systems is concerned. Choice is available and is merely driven by cost considerations.

Vaporization: - Both concepts are equally well placed in this respect.

Send-out: - The gas send-out from the GBS is done via a fixed single riser to the seabed, where the connection with the pipeline is made. On the FSRU, the gas send-out runs via a swivel stack in the turret with 3 toroidal gas swivels. Although this is more complex, the swivel technology is proven and has been applied on several FPSO's. In conclusion, the GBS gas send-out system is considered simpler than that of the FSRU.

Maintenance: - In case a membrane-type containment system is selected for the GBS, external inspection of the tanks is not possible. However, the concrete walls are considered very rigid and any moisture can be prevented from penetrating to the insulation system.. The SPB tanks that are applied in the FSRU can be inspected both internally and externally for cracks or other defects. In case of a defect or leak, the insulation can be removed and repaired in-situ. The FSRU does not have to go to dry-dock.

Stability: - In principle the GBS is a very stable platform. There are however some design risks that have to be adequately addressed: wave impact and run-up, and soil instability. The stability of the FSRU is of a different nature. The vessel is designed to operate in any loaded or ballasted condition in the 100-year design storm, even in case one of the tanks is damaged and water is entering the tanks. Stability should therefore not be a concern. It is judged however that those issues can be solved in the engineering phase. Several large contacting columns are in operation now, and generally their performance improves with motions.

Operability: - For the GBS it appeared that for the selected design data the expected downtime in terms of lost send-out capability is approx. 0.6%. The offloading downtime is approximately 1.2% (also slightly pessimistic). For the FSRU a slightly lower value is expected. Since the differences for this location are insignificant, the results of the downtime analysis have not been further taken into account for the life cycle cost analysis. This situation is likely to be different in case a less benign location is selected.

Safety: - The GBS' thick concrete walls provide protection against collision impact. The concrete is capable to withstand cryogenic spills, dropped objects, or fire and explosion in the topsides plant. The FSRU has different characteristics than the GBS. Cryogenic spills must be mitigated by engineering, and by protective shielding from the hull steel. The topsides have therefore been provided with stainless steel plating underneath. The main deck is protected where necessary with foam or wood.

For the FSRU the risk of a large vessel (LNGC) collision is rather remote for a side-by-side berthing operation. The FSRU is equipped with thrusters, used to keep the FSRU-stern away from the approaching vessel and allowing it to approach head-on to the waves and wind. It is therefore concluded that both systems provide a safe platform for offshore LNG imports.

4) Future phases: - Differences in future phases are related to capacity expansion and decommissioning.

Expandability and re-use: - The GBS capacity can technically be expanded by adding a second structure adjacent to the first one, connected with a bridge. The send-out capacity of the FSRU can be expanded in the same way as for the GBS. It is therefore concluded that both concepts are equally flexible with regard to future expansion.

Decommissioning: - The GBS can be decommissioned by floating, provided that sufficient facilities are built into the unit during construction. Decommissioning of the FSRU is relatively easy. The risers and the mooring chains are disconnected, and the unit can be taken to a scrap yard. A part of the investments can be recovered at scrap value at the end of the life of the unit.

5) Results & Discussion

	GBS	FSRU
Design Phase		
Permitting	o	O
Site selection	--	+
Construction Phase		
Construction site	o	+
Fabrication	o	O
Transport	--	+
Topsides integration	o	O
Site preparation	--	O
Installation	--	+
Schedule	o	+
Cost escalation	--	O
Operational Phase		
Berthing and mooring	o	+
LNG transfer	o	O
Storage	+	+
Vaporization	+	+
Send-out	+	O
Maintenance	o	O
Stability	+	+
Operability	?	?
Safety	+	+
Future Phases		
Expandability and re-use	o	O
Decommissioning	--	+

O = Average, + = Good, -- = Poor

Table 8.1The summarized Result of Technical comparison between GBS-FSRU

Source: Paper on LNG: non-traditional concepts for receiving and regasification the floating storage and regasification unit (FSRU) by Leen Poldervaart and Wim van Wijngaarden

6) Conclusion: -

The comparison between the GBS and the FSRU has revealed a number of interesting differences, some of which were generally qualitatively known, and frequently used as arguments in comparative discussions. In this study an effort was made to quantify several of the cost issues so that the combined results of the technical comparison and the relative cost comparison could be used to support a decision making process, where a justifiable choice between the FSRU and the GBS is sought for offshore LNG import.

The key parameters that nearly exclusively affect the economics of the GBS concept are the water depth, the soil conditions, and the significant wave height. The costs of the hull fabrication materials (steel for the FSRU and concrete for the GBS) have a significant effect on the cost of both concepts. It is therefore vital to have both the GBS and the FSRU built in locations where these costs are low. For the GBS this is not necessarily in low- (labour) cost countries. The GBS has the drawback that it likely has a longer building schedule, which also adds to its cost.

For both concepts the distance to nearby existing pipeline infrastructure is vital as well, to avoid excessive cost penalties for the pipeline. Although the study also addressed the operating costs of both concepts, these were not reported in this paper, since they did not differ much. The maintenance costs for the FSRU were higher, but the GBS showed higher costs for tugs. The extra manning for the FSRU is only 2 persons, and other operating costs were quite similar. Fuel consumption is an important contribution to the yearly operating cost. Although the future decommissioning costs for the GBS are likely quite high and potentially a drawback, this has not been included in the comparison, because of the large degree of uncertainty and the long duration before the expense will have to be made.

In conclusion, the GBS is more expensive than the FSRU, even in its most optimal environment. In benign environments, if the unit can be built in shallow water, and where soil conditions are not cost prohibitive, the difference is relatively modest. However, the upward cost risk for the GBS is much larger than that for the FSRU if the conditions are sub-optimal. Since the FSRU costs are almost independent of the environment, it is easier to estimate the development costs for the FSRU, irrespective of the location. In addition, the FSRU is always less costly than the GBS, unless the pipeline costs are strongly in favour of the GBS.

Finally, the cost of the FSRU can be better controlled than that of the GBS, because the FSRU is built in shipyards, using experienced crews, which is not likely the case for a GBS.

8.5 Converted LNG Carrier Concept

As an alternative to the Floating Storage Regas Unit (FSRU) it is possible for a `virtual' LNG terminal to be created using the LNG carriers themselves. This so called `Energy Bridge' or Converted LNG carrier scheme as initially proposed by El Paso makes use of the LNG carriers as storage vessels, directly regassifying the LNG using additional bow/deck mounted regas equipment.

This scheme has several attractive qualities, most appealing of which is the high operability offered by the internal turret mooring system. Using a submerged turret system it is possible for the LNG carrier to approach and safely connect to a sub sea buoy in up to Hs 5.5 m waves. Once connected the mooring system can safely withstand even North Sea storm conditions (The APL STL system has been successfully deployed in the Offshore Oil and Gas sector in the North Sea region for many years)

Figure 8.5: Illustration of APL Submerged Turret Loading System
Source: Paper LNG import terminals: offshore vs onshore a site & concept screening methodology By Mike Said & Joram Meijerink (Shell global solution international B.V.)

After connection, the carrier can send out gas via a conventional gas swivel down a flexible gas riser to a pre installed PLEM and subsea gas export line. Using the currently envisaged regas equipment, it will typically take up to 6 days to regas the standard cargo parcel of 140,000 m3 of LNG.

It is also possible to create a hybrid version of an FSRU by equipping an existing carrier with a weather-vaning external mooring turret, bow mounted process deck, upgraded power and utility systems and midship mounted LNG loading arms. A carrier converted in such a manner can be used in a very similar fashion to the conventional FSRU described above albeit with a reduced buffer capacity.

8.6 Platform Based Import Terminals (Direct Regas Concept)

A further alternative option for importing LNG exists in the form of direct regas facilities. This option also makes use of the LNG carriers as storage vessels but this time instead of placing limited regas facilities onboard each carrier as is the case with the converted carrier scheme, here one large regas plant is located on an offshore platform.

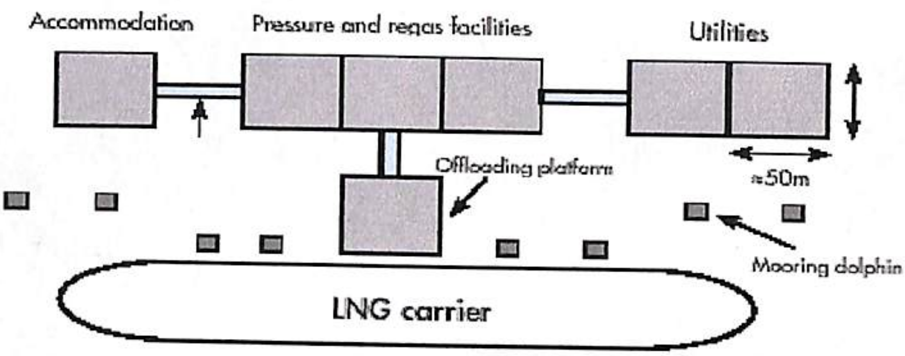


Figure 8.6: Indicative configuration for direct regas facility using offshore platforms

Source: Paper LNG import terminals: offshore vs onshore a site & concept screening methodology By Mike Said & Joram Meijerink (Shell global solution international B.V.)

The carriers will still be required to remain in berth for a longer period than the normal 24 hour offloading period (hence incurring additional demurrage costs) but if the regas capacity can be made high enough this additional duration can be limited to around 12 hours. However, in order for this scheme to work the gas grid has to be able to absorb large amounts of gas in a short period, in addition to the market allowing for an interrupted supply of gas. Alternatively, some sort of gas storage system must be provided.

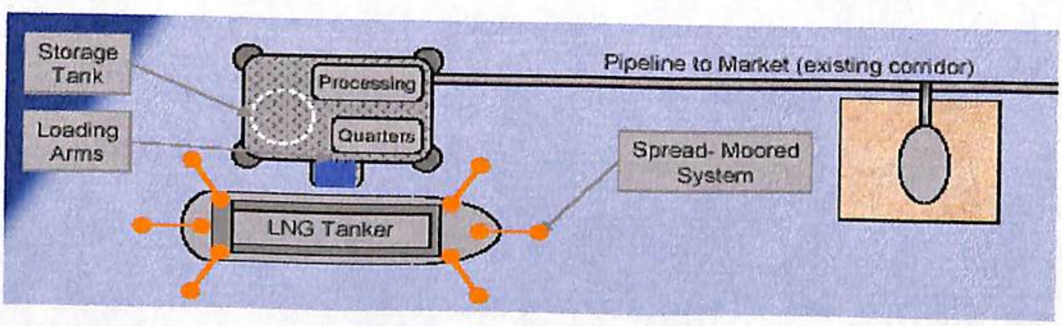


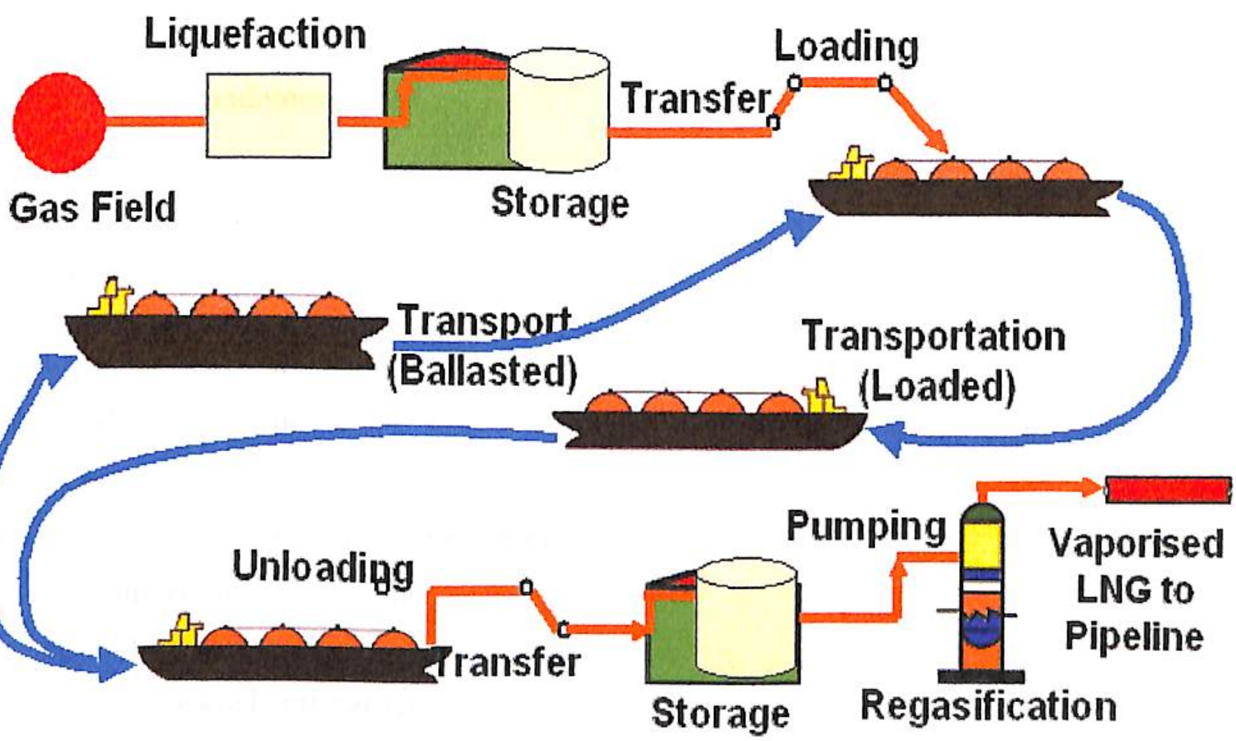
Figure 8.7: Bird Eye view of Platform Based Import Terminals

(Source: Excelerate Energy, **Offshore Liquefied Natural Gas Overview, Public** Symposium on LNG Brunswick, Maine)

Direct regas as a concept is by no means applicable everywhere as it requires some very specific local characteristics to be in place but this in itself serves to emphasise the point that when considering these alternatives careful assessment of all existing local conditions is vital to match the optimum solution to each location.

Chapter- 9

Conclusion



Chapter-9

Conclusion

The world use of natural gas is expected to increase. The LNG industry has an excellent safety record. This strong safety record is a result of several factors. First, the industry has technically and operationally evolved to ensure safe and secure operations. Technical and operational advances include everything from the engineering that underlies LNG facilities to operational procedures to technical competency of personnel. Second, the physical and chemical properties of LNG are such that risks and hazards are well understood and incorporated into technology and operations. Third the standards, codes and regulations that apply to the LNG industry further ensure safety. So for project development and site selection for LNG import terminal the necessary points, which must be considered, are:

Project Development and Site Selection

- Preliminary establishment of need to be achieved through the LNG terminal
- Project identification and formulation
- Feasibility studies to analyse the technical, environmental, commercial and marketing factors
- Local Site
- Permitting conditions

International standards and rules define containment with respect to types of structures and technologies in use. The defining boundary conditions for import terminal design, which must be taken account, are:

- LNG storage volume
- Gas delivery profile
- Gas send out rate
- Gas send out pressure and temperature
- Interrupt ability of gas supply
- Date of first gas
- Size of LNG delivery carrier
- Locations of LNG supply point.

The selection of a possible site for LNG import terminal is depends on location, environmental considerations, operational conditions, safety and economic efficiency as most important ones.

Building up an initial picture of the range of possible sites and concept:

- Metocean data including wind, wave, currents, tides, water temperature and quality, precipitation, fog statistics, air quality
- Admiralty Charts showing bathymetry, shipping lanes, buoys and obstructions, etc
- Site Soil and Sediment data
- Seismic data
- Technical Data on LNG Delivery Carriers
- Shipping Density Statistics
- Existing Relevant Infrastructure (Existing pipelines, platforms, harbours, etc)

So after considering above points, the key factors governed by these data:

- Shipping access & turn around times
- Safety and security of operation
- Use of proven technology
- Expandability of design
- Regas methodology
- Method of power generation
- Air Emissions & water quality
- Pipeline route feasibiltiy

Several *engineering design* features ensure the safety of LNG storage tanks. LNG typically is stored in double-walled tanks at atmospheric pressure. The storage tank is a tank within a tank, with insulation between the walls of the tanks.

Selection of LNG storage rank is based upon:

- Capacity
  - Based On Shipping study
    - Down time analysis for the port facilities
    - Safe operation of LNG ship (berthing, un-loading and stay at berth)
    - Met-oceanic conditions for availability of berth.
  - To cope with reduction in send out rate.
- Type:
  - Based On Rapid Risk Analysis

LNG Tank Safety Analysis

Type of Tank	Scenario For Risk Analysis	Impact
Single Containment	Collapse of Primary Tank	Spillage of tank volume to impounding area
Double Containment	Collapse of Tank Roof	LNG evaporation & release from secondary concrete container
Full Containment	No collapse is considered	NA

Table 11.1: LNG Tank Safety Analysis

LNG STORAGE- Operational Issue

LNG is a relatively safe product to handle provided the following phenomena are carefully monitored and controlled:

- Temperature of the stored LNG / tank's
- Density of the stored LNG / tank.

The reason is that above criteria influence the stability of the stored LNG, resulting in "stratification", possibly leading into the "roll over" phenomena.

- Provided the temperature and density differences of each layer are not in "conflict" with each other, no unsafe condition will occur.
- Density and temperature, which can change / be different due to:
    - Different grades of LNG are stored in the same tank, and / or
    - Natural ageing of (even a single grade of) LNG in a single tank

So in general the selection of a particular tank system depends on location, environmental considerations, operational conditions, safety and economic efficiency as most important ones. Taking these factors into account, Contractor has set the following criteria when considering the type of to be proposed:

- Safety of personnel, operational safety of tanks and associated equipment
- Reliability, ease of operation and maintenance, and efficiency
- No detrimental effects to the environment in case of an accident

The adaptation of well accepted marine technologies; with equally well-accepted **salt cavern storage** technologies have the potential to accommodate a significant increase in the world LNG trade. The major critical elements revealed in this technology are:

- A method to moor and offload an LNG ship
- LNG pumps sufficient to create cavern injection pressures and volume capability to allow acceptable ship discharge times
- A heat exchanger design that will economically warm the LNG at high pressure and high volumes
- Navigable waters sufficient for an LNG carrier to approach
- Salt formations suitable for cavern development
- A pipeline infrastructure sufficient to carry large volumes of gas to market.

Re-gasification system at R/T (Receiving Terminal), to establish an effective operating plan to reduce the operating cost of LNG vaporizing system the study is going on, and to develop a bench scale new type LNG vaporizer for lower seawater temperature. 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 Open Rack Vaporisers 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. 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' utilization process.

The use of an **integrated LNG regasification** and power generation facility could improve the overall profitability of a regasification facility through co-production of LPG and an increase in electric power generation. This new technology also allows LNG importers to accept LNG from a wide variety of sources.

In summary, these new configurations efficiently utilise the LNG as both a working fluid and as a heat sink to achieve the following objectives:

- Meet local natural gas heating value, Wobbe Index, and composition specifications.
- Improve power generation with gas turbine inlet air-cooling.
- Eliminate the costly seawater vaporisation system and its associated environmental impacts.
- Increase total power generation through the use of LNG power cycles that use waste heat from the power plant.
- Recover up to 99% of the propane plus components of the LNG for LPG sales.
- Recover up to 90% of the ethane in LNG for sale or use as gas turbine fuel.
- Produce vehicle quality LNG and CNG as alternate vehicle fuels.

Floating production of LNG allows for development of remote gas fields and utilization of associated gas from oil production. Common to these concepts are that they represents new solutions, which have not yet been proven in practice. Floating LNG is also a flexible development. The plants can be relocated. Also, construction of the facilities can take place in a variety of locations and then towed to final site. It is then possible to optimise the construction strategy.

Savings can be expected, as there is no need for land acquisition, site preparation, and construction of harbour facilities. Project is not sensitive to adverse soil or seismic conditions. Different applications can be expected:

- Valorisation of the associated gas from offshore oil fields, which could not be flared anymore
- Monetizing of stranded gas reserves
- Floating receiving terminal in environment sensitive areas, where it is difficult to locate a land terminal.
- Ultimate gas recovery may be higher, as abandon pressure can be lowered.

The potential advantages of FSRU offshore concept is listed below and applies to both natural production areas as well as LNG endpoint destinations:

- Offshore LNG production removes the demand for infield platform and pipeline infrastructures necessary to transport the produced gas to shore based liquefaction facilities. It is possible that the removal of these intermediate facilities could reduce business risks and increase system availability.
- The development of offshore-based LNG facilities mitigates concerns associated with developing fields in politically unstable areas since the need to develop onshore infrastructures no longer exists.
- Placing LNG production facilities a significant distance from shore removes the risk exposure to the public compared to the onshore alternative. Similarly, environmental impacts associated with initial site clearing and future decommissioning is less of a concern.

The technical challenges that face operators considering floating FSRU facilities are, provided below.

- Offloading LNG from offshore-based operations requires bulk LNG carriers to approach and berth alongside the floating structure. Although similar activities frequently occur with floating petroleum storage operations worldwide, this remains to be a major hazard concern for the offshore option.
- Closely coupled to the hazards associated with approaching LNG carriers, the offloading dynamics would likely involve relative motions between the FSRU and the tanker that exceed those found for onshore based activities where bulk carrier loading is performed at a dedicated, and possibly protected, jetty.
- Similarly to onshore LNG operations, the offshore alternative stores significant amounts of LNG in dedicated storage tanks. A catastrophic tank failure and the subsequent discharge of LNG into the sea could cause serious structural damage to the offshore facility, with possible stability loss.

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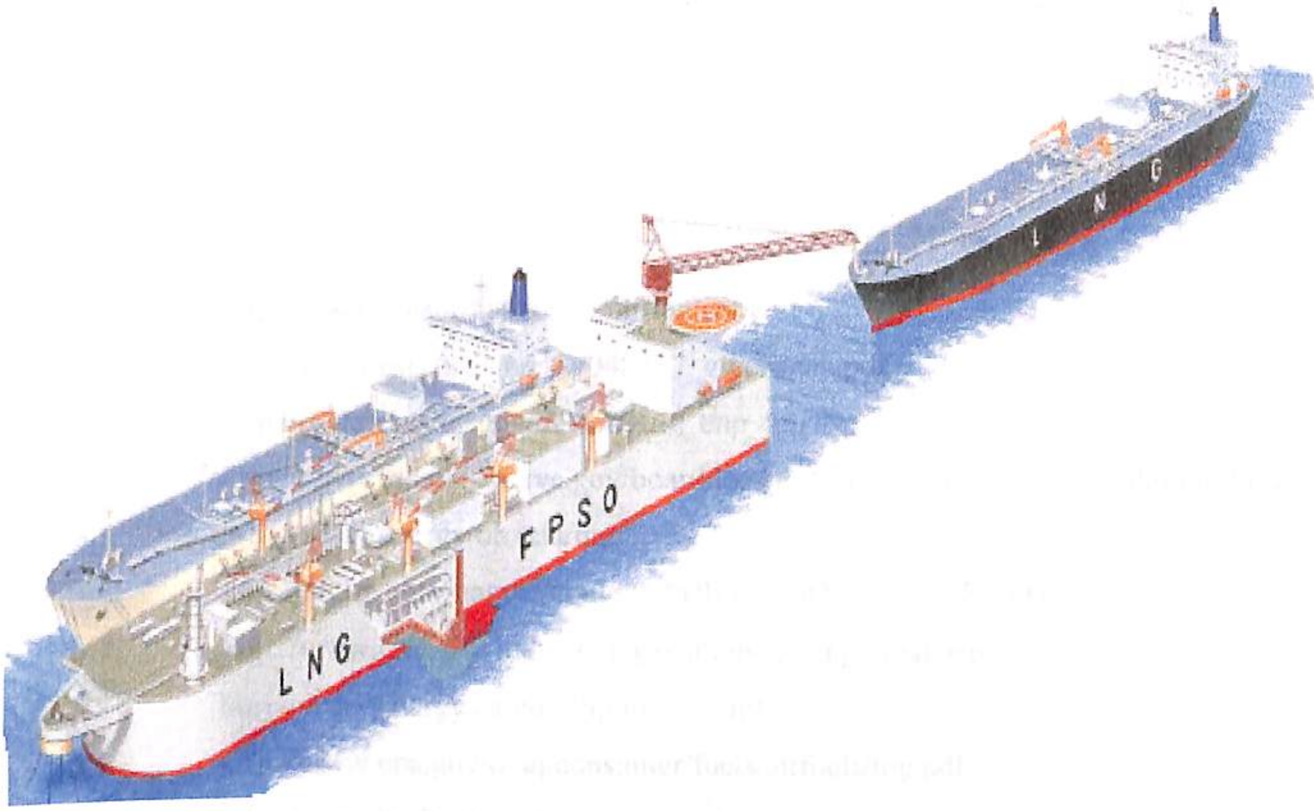

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4. Patents (US Patents Office)

4.1: **Title of invention: "Apparatus and process for vaporizing Liquified Natural Gas (LNG)"**

Inventor: Volker Eyermann

Appl No.: 10/161,431

Field: June 3, 2002

4.2: **Title of invention: "Device for evaporation of liquefied natural gas"**

Inventor: 1. Per Erik Christiansen

2. Olav Natvig Baekken

Appl. No. 10/030,264

PCT Field: Jul 10, 2000

PCT Pub Date: Jun. 18, 2001

4.3 **Title of invention: "Use of Underground reservoir for Regasification of LNG, Storage of Resulting Gas and/ or delivery to conventional distribution system".**

Inventor: Scott James Wilson, Littleton, Co (US)

Appl. No.: 09/954,548

Field: Sep. 17, 2001

Annexures

New Inventions for vaporizing liquified natural gas (LNG)

1. Title of invention: "Apparatus and process for vaporizing Liquified Natural Gas (LNG)"

Inventor: Volker Eyermann

Appl No.: 10/161,431

Field: June 3, 2002

1.1 Brief Description of the Invention

The present invention provides an apparatus and process for vaporizing liquefied natural gas and comprises a circulating water stream, which is heated by ambient air and is used to vaporize the liquefied natural gas. The circulating water system comprises a surge basin for the storage of clean circulating water, several circulating water pumps, a vertical multi-tubular heat exchanger for bringing the warm circulating water into crosscurrent contact with the liquefied natural gas, and a water tower, which is used to warm the circulating water with ambient air. An important feature of this invention is the process to extract heat from the ambient air and to use it to vaporize liquid natural gas, using apparatus, which includes a new combination of elements of proven equipment.

1.2 Brief Description of the Drawing

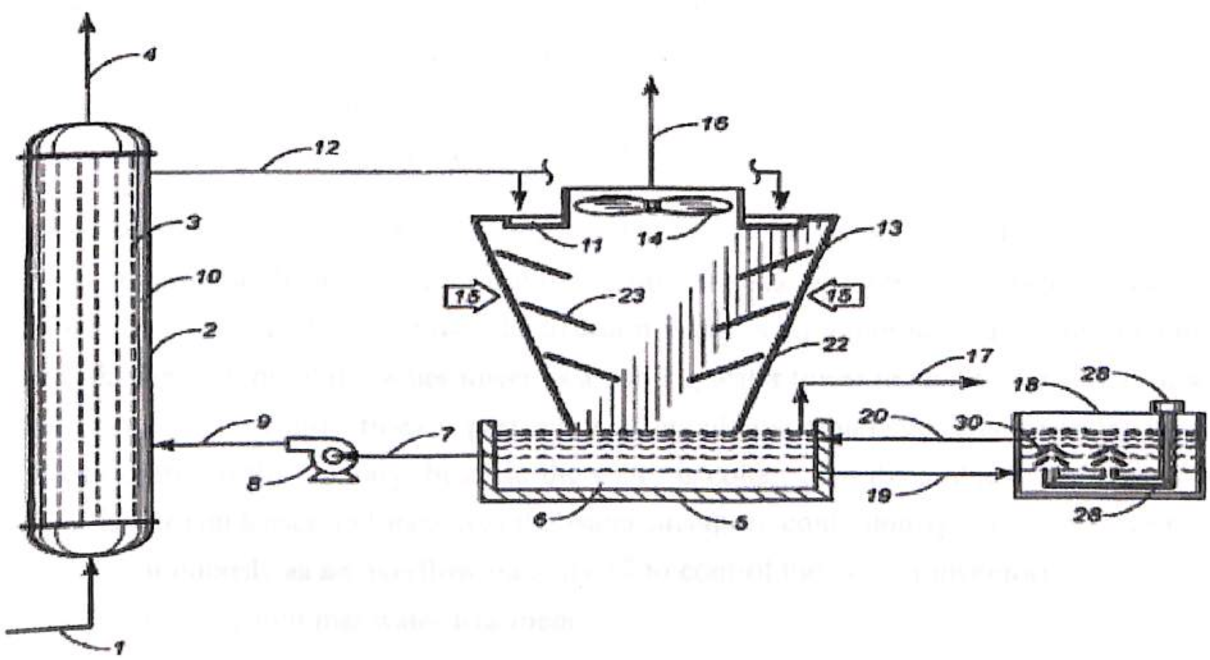

Figure 1.1: Apparatus and process for vaporizing Liquified Natural Gas (LNG)
Source: US Patent Office

1.3 Detailed Description of Preferred Embodiment

As indicated in Figure 1.1, the apparatus and process according to the invention comprises a surge basin 5, a circulating water pump 8, a heat exchanger 2 and a water tower 13. Liquefied natural gas 1 is directed to the bottom of the heat exchanger 2, where it enters tubes 3 of the tube side of the multi-tubular heat exchanger 2 through a proprietary distribution arrangement. The liquefied natural gas 1 is vaporized in the tubes 3 and leaves the heat exchanger as natural gas 4 at a temperature and pressure suitable for distribution in a pipeline system to the users.

Warm water 6 from the water surge basin or container 5 is directed through pipe 7 to the circulating water pump 8 and discharged through pipe 9 to the shell side 10 of the heat exchanger 2. The warm water 6 is directed in cross current flow on the outside of the tubes 3, thereby transferring the heat to the liquefied natural gas 1 and vaporizing it to natural gas 4.

Cold circulating water 11 leaves the shell side 10 of the heat exchanger 2 via pipe 12 and is directed to the top distribution channel of water tower 13. Water tower 13 has an outer frusto-conical wall 22 having perforations or openings therein for the flow of ambient air through wall 22. Baffles 23 are mounted in water tower 13 adjacent wall 22. Cold water 11 overflows an upper distribution tray or pan in water tower 13 in a controlled manner and cascades downwardly along baffles 23 into the lower water basin 5. Fan 14 draws warm ambient air 15 through openings in wall 22 of water tower 13 from the side of water tower 13, thereby warming up the water 11, which is cascading downwardly in water tower 13 and which arrives in surge water basin 5 as warm water 6. Cold water 11 cools the air 15 as it heats up to warm water 6, and the fan 14 at the top of the water tower 13 discharges cold air 16.

The heat exchanger 2 is a vertical so-called shell-and-tube heat exchanger. It is in use in many installations and need not be modified for use in this process. The water tower 13 is used as a device to warm cold water. The use of water tower 13 to warm water is an important feature in this invention. Contrary to the application of the water tower as a cooling water tower to cool warm water, in which a water loss occurs continuously from vaporization of circulating water, there is no water loss in the present application. To the contrary, because the water is colder than the ambient air, water from the moisture of the air condenses and increases the water inventory continuously. The excess water has to be drawn off continuously as an overflow quantity 17 to control the system inventory and may be used as fresh water after very minimal water treatment.

Even in warm climates like that of the southern USA this process cannot work all year round because the air cools off in the months of November to March.

In the winter season, at least partial supplemental firing of conventional submerged fired liquefied natural gas vaporizer(s) 18 is required to assure continuous operation throughout the year. These submerged fired heater(s) 18 having submerged combustion chambers 26 with gas furnaces 28 need to be modified to replace their internal liquefied natural gas exchanger tubes with internal baffles 30 to improve mixing of the flue gases with the circulating water. A pump internal to the submerged fired heaters 18 pumps warm water 19 from the basin 5 to the submerged fired heater 18 and returns additionally warmed water 20 back to the basin 5.

2. Title of invention: "Device for evaporation of liquefied natural gas"

Inventor: **1. Per Erik Christiansen**

2. Olav Natvig Baekken

Appl. No. **10/030,264**

PCT Field: **Jul 10, 2000**

PCT Pub Date: **Jun. 18, 2001**

2.1 Abstract of invention

A device for evaporation of liquefied natural gas (LNG) on board a vessel. The device includes a pipeline through which LNG flows. The outside of the pipeline may be brought in contact with a heating medium, for example seawater. The pipeline is immersed in the sea and is connected to the vessel. The pipeline is enclosed by a shell through which seawater is pumped by a pump, which is operated by a motor on board the vessel

2.2 Brief Description of the Drawings: -

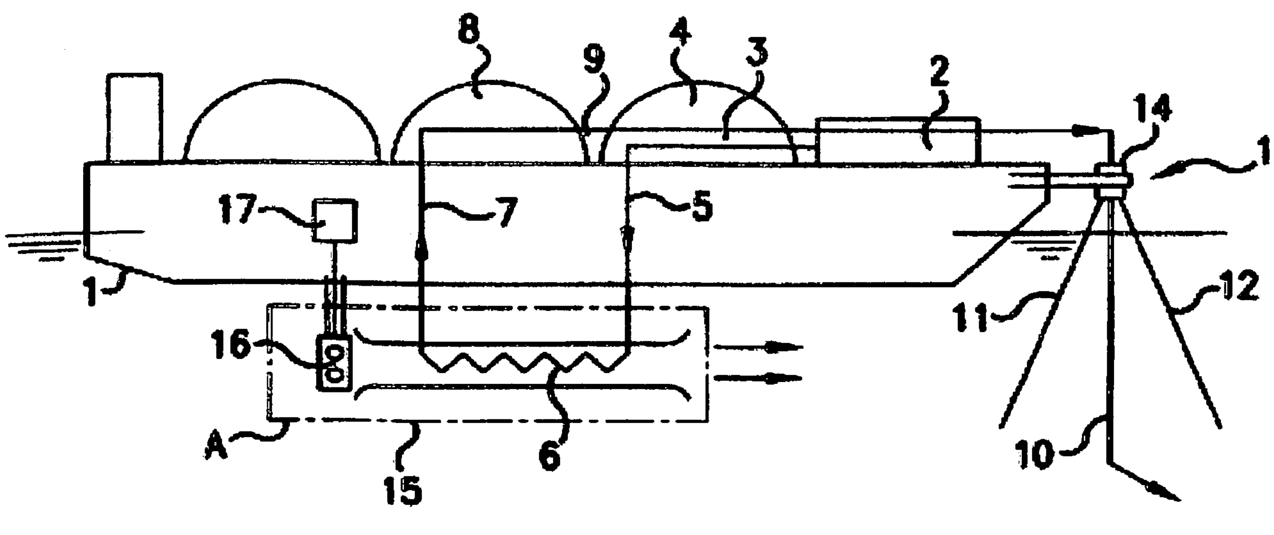

Figure 2.1: A schematic side elevation showing a floating vessel, which carries a device according to the invention (Source: US Patent Office)

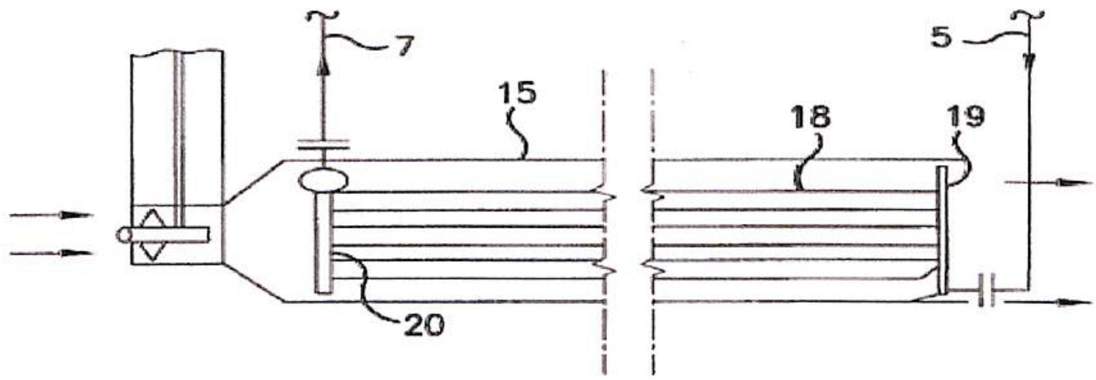

Figure 2.2: An enlarged sketch of the section, which in Figure 2.1 is designated A.
Source: US Patent Office

2.3 Detailed Description of the Invention: -

A vessel 1 which may be anchored near a jetty (not shown) or moored to it comprises a control- and metering device 2, for receiving LNG which is pumped from the supply ship (not shown), and for discharge NG to the consumer pipe network pipelines (not shown) anchors.

From the control- and metering device 2 a line 3 is extending to a tank 4, in which the LNG is stored, and from tank 4, a pipe 5 leads to one end of a pipe or pipe device 6, which is immersed in the sea beneath the vessel 1, and which acts as a vaporiser. From the other end of pipe 6, a pipe 7 leads to for example a storage tank 8 for NG, and from this tank 8 a pipe 9 leads to the regulator and metering device 2. From the control -and metering device 2, a pipe 10 is leading to one or more consumers of NG, for example via a consumer pipe network system anchors (not shown). The vessel is moored by means of anchor chains, 11, 12, which are connected to the vessel at a location 13. At said location 13, a swivel 14 may be arranged for the anchor chains 11, 12 and the line 10, so that the vessel may rotate around this point, for example under the influence of wind without twisting of anchor cables and the pipe.

A tubular shell 15 encloses the pipe 6. A propeller 16 which may be operated by means of a motor 17 on board the vessel 1 is arranged at an end of the shell 15, which faces away from the mooring cables 11, 12. By operating the propeller 16, seawater is forced through the casing 15 and around the pipe 6 in a direction towards the mooring cables 11, 12. In this manner the propeller provides a current of relatively warm seawater around the pipe 6 causing evaporation of LNG, and at the same time provides a thrust on the vessel 1 away from the mooring cables 11, 12, holding them tight and straight.

2.4 Functions of the device

From a ship transporting the LNG and which has been moored close to the vessel 1, a pipe (not shown) is being connected to the control -and metering device 2. Subsequently LNG is pumped from the ship to the LNG tanks 4 of the vessel, from where LNG may be pumped to the pipe or pipe device 6. This is of sufficient length that all LNG, which is introduced at the inlet, has been evaporated to NG at the pipe exit. This evaporation is caused by seawater, which is forced through the shell by means of the propeller 16 and transfers a part of its heat energy and is thereby reduced in temperature.

The produced NG is subsequently transported to the tank 8 used for storing of NG, from where NG is further transported to the control -and metering device 2. The amount, which is to be supplied to the consumer pipe network via line 10, is at this point measured and metered.

Typical seawater temperatures at the inlet of the shell may be 15[deg.] C., and at the shell exit approximately 5[deg.] C.

It is to be understood that by arranging the evaporating pipe or evaporating system 6 near the vessel 1, there is no need for long pipelines, which is the case for the known technique. It is further to be understood that the plant may function without the collecting tanks 4 respectively 8, as LNG and NG may be pumped directly to and from the pipe 6 via the control -and metering device 2. It is also to be understood that the power requirement for pumping of LNG through this vaporiser is considerably less than the power requirement of a traditional evaporator as described above. Investment costs as well as operating costs are therefore considerably less than traditional vaporising installations. There are also far less environmental effects.

Figure 2.2 is an enlarged sketch of the section, which in Figure 2.1 is designated A. It is shown that a pipe arrangement 6 of the vaporiser may comprise a series of single pipes 18 that pass between a inlet manifold 19 and an outlet manifold 20.

Inventions for storage & vaporizing of liquified natural gas (LNG)

3.Title of invention: "Use of Underground reservoir for Regasification of LNG, Storage of Resulting Gas and/ or delivery to conventional distribution system".

Inventor: Scott James Wilson, Littleton, Co (US)

Appl. No.: 09/954,548

Field: Sep. 17, 2001

3.1 Introduction

The present invention is a method for re-gasifying Liquefied Natural Gas (LNG) in a subterranean formation/cavity, storing the resulting gaseous hydrocarbon in the same or connected strata, then subsequent conventional production and delivery of the gas to end users. LNG is injected into a permeable subterranean reservoir through surface and wellbore equipment suitable for operations at cryogenic temperatures. The liquid hydrocarbon vaporizes in the permeable rock/cavity near the injection wellbore as it gains thermal energy from the surrounding strata. The resulting gas is held within the reservoir for subsequent production and/or immediately produced by producing wells in the same or contiguous formations. The invention eliminates the need for onshore LNG receiving/storage terminals.

3.2 Background for this invention

At the conventional LNG receiving terminal docks capable of berthing an LNG tanker, cryogenic pumps and piping capable of transferring LNG from the tankers to the storage tanks, cryogenic storage tanks, re-gasification equipment, a source of heat capable of introducing sufficient heat to vaporize the LNG, piping connections and measurement facilities for metering and delivering the gas into a natural gas distribution system equipments required.

Problems associated with these receiving facilities include the high cost and risk of berthing ships along coastlines at specialized docks capable of receiving LNG tankers, the high cost of cryogenic storage facilities, the cost and energy required to convert the LNG back to gaseous form, and the need to install new pipelines and metering systems required to deliver gas to a transmission line or gas distribution system. Also, the safety precautions required to berth and unload ocean-going LNG tankers creates complexities since onshore facilities near population centers are discouraged due to a real or perceived probability of industrial accidents. The very large initial capital investment, significant recurring operating costs, and environmental and community related drawbacks have discouraged construction of onshore receiving facilities.

So the objectives of this invention are to use the ambient temperature and warming capacity of subsurface formations to gasify the LNG injected into the subsurface reservoir, to use existing porous reservoirs to store LNG in gaseous form, to obtain a more economical and efficient method of delivering LNG to the market and to use existing transmission systems in fluid communication with the reservoir to deliver natural gas to the market.

3.3 Brief Description of the Drawings

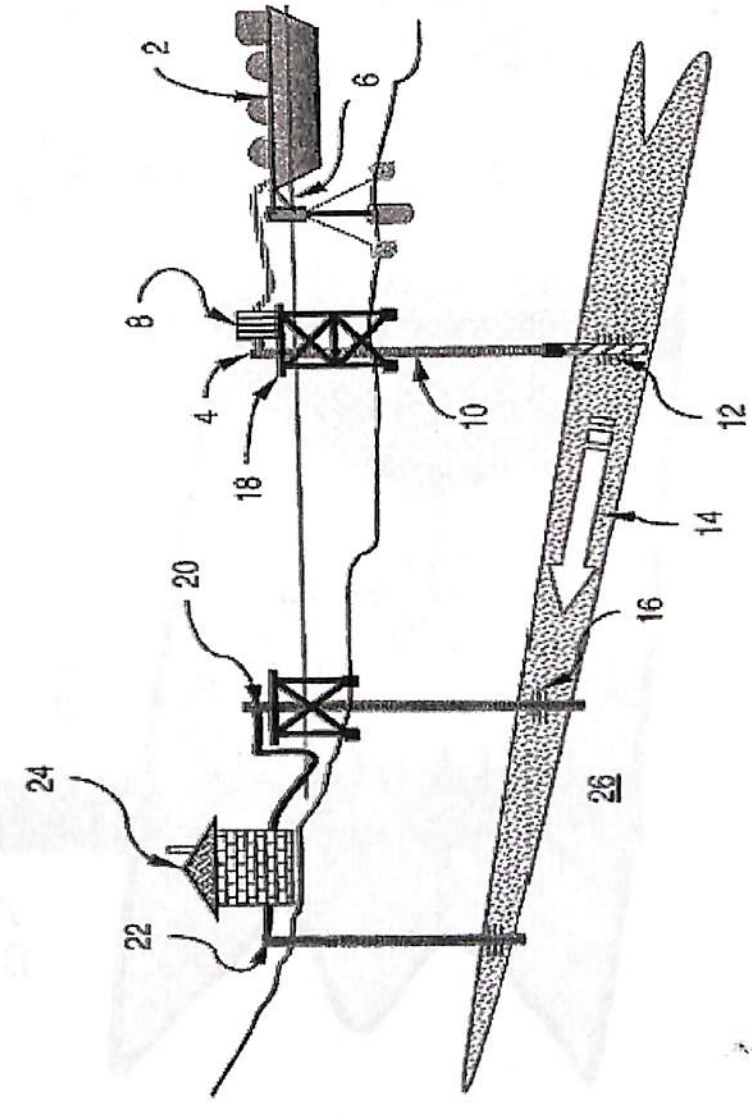

Figure 3.1: An elevational view of an LNG tanker off-loading LNG into an injection well in fluid communication with a reservoir that is in fluid communication with two production wells.

Source: US Patent Office

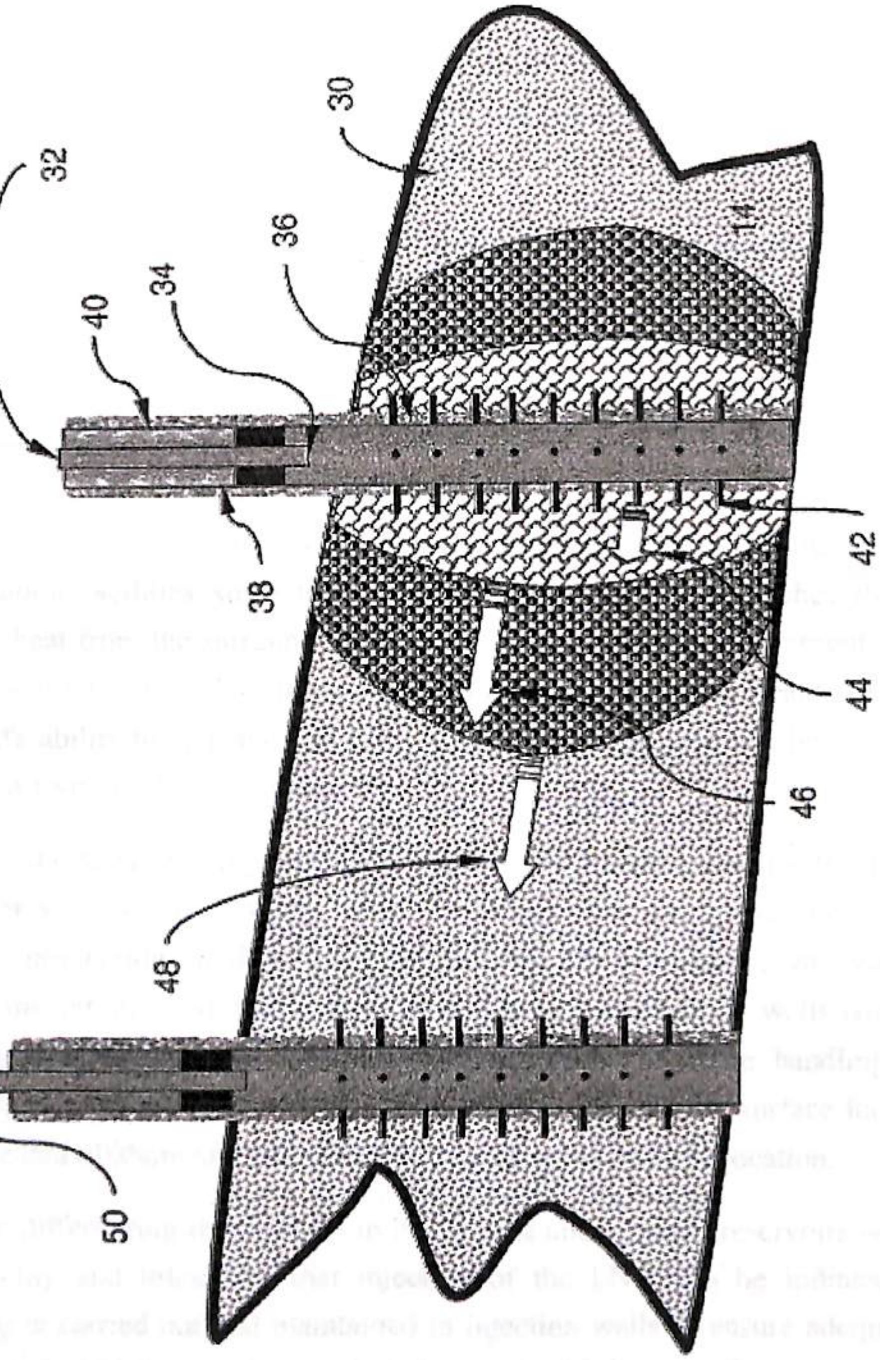

Figure. 3.2: An elevational view of an injection well capable of receiving cryogenic fluids in fluid communication with a gas reservoir that is also in fluid communication with a production well.
Source: US Patent Office

3.4 Description of the Preferred Embodiments

This invention relates to improvements in the method of delivering LNG to conventional gas users by eliminating onshore surface receiving cryogenic storage facilities. The initial capital cost, the ongoing operations expense, the onshore land acreage, operations manpower, and shoreline community hazards, and exposures to risk are reduced by this invention.

These benefits are accomplished by offloading LNG from tankers directly into conventional subterranean reservoirs through traditional injection wells fitted with wellbore equipment capable of operations at cryogenic temperatures. The LNG tanker can be berthed at offshore unloading facilities in close proximity to the injection wellheads. The wellheads can be located on a multi-well platform, on single well structures, on the sea-bottom with a surface tie-in injection lines, on near shore injection wells and on other facilities tied into a cryogenic transport line from the tanker to the injection well. The LNG is stored in gaseous form in subterranean reservoirs at ambient conditions. The invention eliminates re-gasification facilities since the LNG is vaporized after it reaches the subterranean reservoir by utilizing heat from the surrounding strata to gasify the LNG. The present invention takes advantage of the ambient temperatures of the subterranean reservoir to impart heat to the injected fluid, and the injected fluid's ability to displace and remove liquid water in near wellbore areas that would normally decrease injectivity of the injection well.

The invention reduces the need for gas gathering, metering, and transmission line tie-ins if a reservoir is used that was previously or currently used for traditional gas production. If a recently decommissioned gas production field is used or one still on production, gas gathering and/or transmission line tie-ins can be used. Gas can be produced from production wells concurrently with LNG injection or as demand requires. This invention simplifies offshore handling if a suitable reservoir that is in fluid communication between the offshore and onshore surface locations is used, since LNG can be injected offshore and natural gas produced at the onshore location.

The present invention differs from the prior art in that it uses underground reservoirs with sufficiently high native permeability and infectivity that injection of the LNG can be initiated. In addition, wellbore conditioning is carried out and maintained in injection wells to ensure adequate infectivity. Conditioning includes minimizing water saturation by repeated injection of dry gas, thus decreasing water saturation by evaporating, vaporizing, subliming, and absorbing water in which the LNG comes in contact. The effect of the reduction in water saturation in the flow paths followed by the LNG will be to maintain permeability with respect to the injected LNG.

Gas resulting from re-gasification of LNG is dry: i.e., contains no measurable water in liquid or vapor form, and will come to thermodynamic equilibrium with the water in the reservoir until the gas becomes water saturated. This gas is produced to the surface and any undesirable water is removed before being sent to the gas purchaser, resulting in a net decrease in the water within the reservoir. Although the total amount of water in the reservoir cannot be affected significantly, the area around the injection well bores can, since the near-wellbore area will be flushed extensively with water-free gas/LNG. Since no additional water is introduced into the reservoir near the injection well, the flow paths taken by the LNG/gas will eventually become water-free. For example, one million cubic feet of a typical water free natural gas at 150[deg.] F. and 1000 psia can absorb 220 pounds of liquid water while coming to equilibrium with a liquid water saturation Therefore, a single tanker load of 3 bcf (billion cubic feet) of LNG could remove 660,000 pounds or 1900 bbls of water from the flow paths of the LNG/gas. The resulting water-free flow paths will provide excellent conduits for future injection of LNG. Injectivity should continue to improve until it approaches a highly favorable single-phase liquid relative permeability.

Injection of LNG continues until offloading of the tanker is complete. The gas reservoirs best suited are those that have flow capacities above about 1000 md-ft and preferably above about 10,000 md-ft, and most preferably above 100,000 md-ft. The permeabilities and injection rate of the injection well should permit offloading of the LNG at rates of about 1000 bbl/day to about 50,000 bbl/day and preferably about 10,000 bbl/day to about 50,000 bbls of LNG/day. The reservoir should also have gas "storage" volume sufficient to accept a full load of LNG without over pressuring the reservoir. In addition, the reservoir should not have a water influx greater than about 1000 bbl/day to about 10,000 bbl/day and preferably about 0 bbl/day to about 1000 bbl/day: this will help the reservoir to maintain containment-like behavior and reduce the introduction of new water to injection well bores that have been de-watered and/or conditioned to reduce water saturation. Heat flux into the reservoir from surrounding strata will bring the gas to ambient temperature in a matter of days. It is preferred that the reservoir not be significantly affected by an aquifer that would re-introduce substantial quantities of water into the reservoir.

If LNG injection does not sufficiently decrease water saturation, other methods of decreasing water saturation near the wellbore can be used to pre-condition injection wells for LNG injection. These other methods include the use of fireflood techniques to vaporize and displace water around the injection wellbore, injection of surfactants to allow increased gravity related water drainage, injection of chemicals to absorb and/or adsorb water off of the reservoir rock, or other dehydration methods used in the current art.

By reducing or eliminating water saturation in the injection well, injection of LNG should follow the same pressure-flow rate relationships commonly used in the current art of petroleum reservoir engineering as defined by Darcy's law. Darcy's law states that the flow-rate through porous media is proportional to the cross sectional area, the permeability, and the pressure differential, while flow-rate is inversely proportional to the viscosity of the flowing fluid and the length of flow path. Wells capable of injecting a 0.12 centipoise liquid at the required flow are common in the prolific sands of the U.S. gulf coast and other coastal offshore subterranean reservoirs throughout the world.

Injection rates in injection wells sufficient for efficient offloading of large LNG tankers (135,000 m<3>) are generally within the range of about 20,000 bbl/day/well to about 50,000 bbl/day/well and preferably about 50,000 bbl/day/well to about 100,000 bbl/day/well and most preferably above 100,000 bbl LNG/day/well. To accomplish a one-day offloading turnaround, approximately 10 injection wells are required. Horizontal and fractured wells can be used to provide higher injectivity if necessary. In the Gulf of Mexico, wells capable of injection at these rates are currently producing gas into well-established gas gathering systems.

As the pressures in existing, state of the art reservoirs are depleted, the producing zones may be abandoned and the wells plugged. A few of these same wells could be "unplugged" and used for LNG injection, the low pressure reservoirs used for storage, and the multitude of current platform, gathering systems, and producing wells used for production as-is; thus, this invention could avoid the great expense presently incurred in the current art in abandoning these platforms and wells. Gas reservoirs suitable for this invention can be described as high permeability, competent porous formations with low pressure due to depletion, but high fracture gradients so that the formation can be repressured completely if desired. The size of the reservoir should be large enough to meet the needs of the LNG delivery schedule in conjunction with the gas off take schedule. A preferred embodiment has existing gas production wells and gathering, metering and trunk line connections so that delivery to the gas distribution network is simple.

Injection wells suitable for this invention can be described as fitted with cryogenic capable injection lines, wellheads, and tubulars and preferably wellbore equipment and casing strings. Large tubular strings of at least 3[1/2]" outer diameter and preferably larger will enable larger injection rates. Tubular strings preferably should be fitted with multiple expansion/contraction joints or other means to allow anticipated movement due to temperature fluctuations. Tubing strings should also be fitted with sufficient pressure relief systems to accommodate a blockage and resulting reverse flow after the wellbore fluids re-gasify

The present invention greatly simplifies the process of receiving and storing LNG in locations where conventional offshore oil and gas fields exist. Since these fields generally deliver gas into the gas transmission system, the ability to move ocean-borne LNG to end-users is more efficient and economical than conceived in the prior art. In its simplicity and efficiency, the present invention not only eliminates the cost and hardship incurred in building new facilities, but also extends the productive lives of offshore gas production assets considered uneconomic and soon to be permanently abandoned

3.5 Description of the Drawings

Figure 3.1 illustrates the preferred method for carrying out the injection, re-gasification, storage, and ultimate delivery of hydrocarbon gas previously existing in the liquefied form. LNG tanker 2 delivers a load of LNG to offshore injection well 4. Docking facilities 6 similar to those used in Floating Production and Storage Operations (FPSO) vessels can be used to tether and maintain position of the LNG Tanker near the injection well location. Transfer pumps 8 capable of handling cryogenic fluids housed either on the tanker itself, on the wellhead platform 18, or on a service vessel are used to transfer LNG from the tanker to the injection well. After the lower section 10 of injection well 4 is sufficiently cooled, the LNG (some of the LNG may be converted to gas due to heat being absorbed by the LNG) begins dispersing out through perforations 12 into the subterranean gas reservoir 14.

While liquefied gas contacts the underground formations, it is heated by the ambient heat present in subterranean formations 26 and in the reservoir itself 14. LNG continuously vaporizes and moves toward lower pressures that exist in other parts of the reservoir near producing wells 20 and 22. Given sufficiently high injection rates, vaporization may not occur until the LNG has flowed away from the injection well 10. However, the capacity of the formation to warm the LNG to ambient conditions is essentially infinite, so the LNG will eventually return to a gas phase and approach ambient temperature. The resulting increase in pressure as the LNG returns to the gas phase will force flow toward lower pressure production wells and areas of the reservoir farther away from injection sources.

High permeability, low-pressure reservoirs of moderate size (10-15 bcf) provide the best reservoirs for application of this invention since such reservoirs require low injection pressure to introduce LNG into the formation, move gaseous hydrocarbon quickly to producing wells, and provide high deliverability at the producing wells. There is no requirement for a specific size. However, a reservoir size of less than a tanker load (approximately 3 bcf) could be used as a regasification means and alternate docking method to conventional LNG facilities. Larger reservoirs could be charged continuously or seasonally for long-term gas storage and/or peak production needs.

Even those reservoirs that have previously been abandoned may be candidates since their production characteristics are well known, thus reducing the risk associated with unpredictable reservoir performance.

The benefits of injecting gas in liquefied form are many. No re-gasification equipment is required. Injection is accomplished with pumps 8, which are simpler and less expensive than the compressors that would be required for the same mass injection rates of gaseous hydrocarbons. The hydrostatic head of the injection liquid provides additional pressure energy for injection since the accumulated mass of the LNG in the wellbore serves to push LNG into the reservoir 14. Conversely, producing wells can be located offshore 20 or onshore 22 if the subject reservoir extends onshore. In general, using the LNG injection wells for subsequent production is not advised, since this could re-saturate the near-wellbore region of the injection well with water produced along with the gas. Once delivery of the gas is needed, gas is produced from production wells into a gathering system or gas transmission system 24.

Figure 3.2 illustrates the present method for delivering LNG to the underground gas reservoir 14. LNG is injected from a surface location into a cryogenic tubing string 32. LNG moves down the wellbore at velocities exceeding the bubble rise velocity of natural gas, which is approximately 7 feet/second. LNG exits the wellbore 34 in gas and/or liquid form into the open casing 36 that is adjacent to the reservoir. Technology developed for the steam flood and LNG handling industries can be used in constructing competent well bores for purposes of injection. The current art in these industries includes ductile metallurgies at cryogenic temperatures, expansion/contraction fittings and seals, and insulated casings and cements 38. Low heat-flux annular fluids like gelled diesel can be used to isolate upper sections of the wellbore from extreme temperature variations 40 and maintain LNG in liquid form if it is deemed advantageous. The present invention incorporates injection into the formation in either gas, liquid or mixed phase; during the offloading of a tanker all three phases may exist at times. After the LNG enters the casing 36, it is forced into conventional perforations 42. After traveling the length of the perforations, it flows into the outer reaches of the reservoir 14. The area of the reservoir near the injection wellbore 44 will have extremely low water saturation after the LNG and dry gas has been injected for a sufficient time to remove the liquid water in the pore spaces. For the maximum injection rate, LNG will move as a liquid away from the wellbore toward lower pressures.

As the formation warms the LNG, the LNG begins to vaporize 46 and moves away from the LNG saturated areas of the formation toward production well 50. After the ambient temperature of the formation heats the LNG to gasify it, the gas moves within the gas reservoir 14 according to pressure gradients induced by production and injection wells.

Gas can remain in the reservoir until seasonal or cyclic demand requires production of the gas through production well 50 or can be produced concurrently with injection.

While the foregoing preferred embodiments of the invention have been described and shown, it is understood that the alternatives and modifications, such as those suggested and others, may be made thereto and fall within the scope of the invention

3.6 This technique provides the following claims

1. A method of storing natural gas comprising liquefying natural gas to obtain liquefied natural gas ("LNG"), transporting the LNG to a location near a subterranean reservoir within a formation, off loading the LNG into the reservoir, and permitting the ambient heat of the formation to vaporize the LNG into the natural gas.

2. The method of claim 1 wherein the LNG is offloaded into the reservoir through at least one injection well in fluid communication with the reservoir.

3. The method of claim 1 wherein the gas is withdrawn from the reservoir through at least one production well in fluid communication with the reservoir.

4. The method of claim 1 wherein the gas reservoir has a flow capacity, with respect to gas, of at least about 1000 md-ft.

5. The method of claim 1 wherein the reservoir has a flow capacity, with respect to gas, of at least about 10,000 md-ft.

6. The method of claim 1 wherein the reservoir has a flow capacity, with respect to gas, of at least about 100,000 md-ft.

7. The method of claim 2 wherein the injection well is capable of receiving cryogenic fluids.

8. The method of claim 2 wherein the injection well is capable of injection rates of the LNG in the range of about 1,000 to about 100,000 barrels per day.

9. A method of storing natural gas comprising liquefying the natural gas to obtain liquefied natural gas, ("LNG"), transporting the LNG to a location near a subterranean gas reservoir wherein the reservoir has a flow capacity of at least about 10,000 md-ft, offloading the LNG into the reservoir through at least one injection well capable of receiving cryogenic fluids and which is in fluid communication with the reservoir, permitting the ambient heat of the formation to vaporize the LNG back into the natural gas, and withdrawing the natural gas through at least production well in fluid communication with the reservoir.

10. The method of claim 9 wherein the reservoir has a flow capacity, with respect to gas, of at least about 100,000 md-ft.

11. The method of claim 9 wherein the injection well is capable of injection rates of at least about 10,000 to about 50,000 barrels of LNG per day.