Liquefied Natural Gas (LNG) - An Introductory Course

Course No: P04-006
Credit: 4 PDH

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Introduction

LNG was first made in the early 1900s when, in order to extract helium from natural gas, the gas was chilled to the point where LNG was formed and what remained was the mostly helium in gaseous form.

The first commercial use of LNG was in Cleaveland Ohio, when 4 LNG tanks were installed at the Cleveland gas facility. The tanks were made of 3.5% nickel steel which was not adequate to store the super cold LNG. One tank failed in a brittle manner which caused a second tank to fail. LNG ran into the sewers, which caused the LNG to pressurize the sewer system; pushing gas into many buildings in the area. It was a tragedy that resulted in the death of over 140 people and the destruction of many buildings around the plant. The use of LNG in the United States came back in the mid-1960. Most of the LNG facilities in the United States were built in the mid-1960s and 1970s.
Also, during that time, import terminals were built which allowed the import of LNG by tanker ships to the United States.

Today, many of these import terminals have been converted to import/export terminals, and the United States has switched from being a net importer of natural gas to a net exporter of natural gas due to LNG export.

LNG has become a worldwide energy commodity that is in very high demand. It is the fossil fuel that produces the least amount of greenhouse gas when burned.

This learning document is meant to be at an introductory technical level. **The most important intention of this document is to give you the basic technical knowledge, at an introductory level, that you need to start your study, on how to continue to make the Liquid Natural Gas Industry "Safe and Reliable".**

The image to the right is placed here as a reminder, that everyone has a someone who loves, and needs them, to come home at their end of their shift.

The reason reliability is also related to safety is because, if the LNG plant cannot make sendout when needed, the consuming public may be out of gas during the worst of cold weather times. This would put the public at a severe health risk.

We, as engineers, need to assure that our designing, planning, operating and maintenance, of LNG facilities, helps assure safety and reliability.

This will help assure that everyone comes home at the end of their shift, and that gas is supplied, when needed by the end-use customers.

Culture

Plant Safety

Figure 1: Beautiful Granddaughter

Source: Self-Made photo

Terms and Units of Measure for Natural Gas and LNG

The following abbreviations, terms and units will be used in this document for natural gas and LNG:

U.S.	United States
Peak Shaver	An LNG facility used to supplement the supply of natural gas during times of high gas demand
Satellite	An LNG facility used to supply gas to a localized area
Sendout	Natural gas or vaporized LNG sent out, by a gas utility, via pipelines to customers
Boil-off gas	The gas that boils off from an LNG tank as heat is leaked into the tank from the environment (sometimes just called boil-off)
F	Degree Fahrenheit (a measure of temperature)
Psia	Pounds force per square inch absolute (above absolute zero)
Psig	Pounds force per square inch above atmospheric pressure
Lbm	Pound mass
Lbf	Pound force (the force exerted due to 1 lbm accelerated at 32.2 ft./sec^2)
Cu.ft.	A cubic foot of volume 1 foot x 1 foot x 1 foot (1' x 1' x 1')

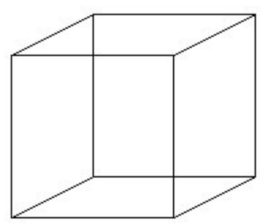

Figure 2: Cubic Foot is a volume 1' x 1' x 1'

Source: Self-Made

BOG	Boil-off gas
SCF	A standard cubic foot is a 1' x 1' x 1' volume of gas at a standard temperature and pressure. For this document, the American Gas Association (A.G.A.) definition of standard pressure and temperature of 14.73 psia and 60 F is used.
BTU	Btu is the amount of energy needed to raise 1 lbm of water 1 deg F. This is not a precise measure of energy because different industries and different countries use a different standard temperature of the water being heated. The heat capacity of water differs with temperature.

HHV	Higher heating value is the amount heat released from burning a SCF of natural gas at 60 F with air at 60 F and bringing the combustion products down to 60 F.
Therm	By definition, a Therm is 100,000 Btu.
Dekatherm	Deca means 10, so a dekatherm is 1,000,000 Btu.
MSCF	In the U.S. Gas Industry, "M" means 1,000. Thus, MSCF is 1,000 SCF.
MMSCF	In the U.S. Gas Industry, "M" means 1,000. Thus, MMSCF is 1,000,000 SCF (one million standard cubic feet)
BSCF	In the U.S. Gas Industry, "B" means billion. Thus, BSCF is 1,000,000,000 SCF (one billion standard cubic feet)
Gallon	Is an imperial unit measure of volume.
m	A meter is a measure of length in the International System of Units
m^3	A volume measurement 1 meter x 1 meter x 1 meter

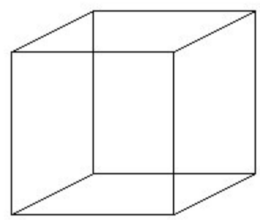

Figure 3: Cubic Foot is a volume 1' x 1' x 1'

Source: Self-Made

Nm^3	Normal cubic meter is a cubic meter volume of gas at a defined "Normal" temperature and pressure. Different countries and different industries use different values for "Normal" properties.
Barrel	There are two different barrel terms, one for the Alcohol Industry and the Petrochemical Industry. For this training, the Petrochemical Industry Barrel will be used. 1 barrel = 42 gallons

Approximations used in this training:
$1\ m^3 \sim 35.3\ ft^3$
One cu. ft. of LNG ~ 600 SCF of vapor
One cu.ft. ~ 7.48 gallons
1 gallon of LNG ~ 80 SCF of vapor

Facilities in the United States and Codes that Govern them

The Federal Energy Regulatory Commission (FERC) governs most permanent LNG facilities in the U.S. via the federal code of regulations (code 49CFR193). This code requires the governed facilities to abide by the consensus code, National Fire Prevention Association (NFPA) 59A. Many countries around the world also conform to NFPA 59A.

The U.S. Pipeline and Hazardous Material Association (PHMSA) collects data on LNG facilities annually. According to PHMSA, the inventory of LNG facilities as of 10/1/2022 for the 2021 annual reporting year is as follows:

https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

- 71 Peak Shaver (PS) LNG Facilities (48 with liquefiers)
- 23 Satellite (Sat) LNG Facilities (1 with liquefier – that is how it is reported)
- 26 Base Load LNG (liquefiers - not counted)
- 40 Mobile or temporary LNG facilities
- 8 Other LNG facilities
- Of the 94 Peak Shaver and Satellite LNG facilities, 44 (47%) facilities in the Northeast
- Of the 94 Peak Shaver and Satellite LNG facilities, 72(77%) 1960’s – 1970’s vintage
- Of the 48 PS and Sat in the Northeast U.S., 40 (83%) 1965 – 1975 vintage
- Of the 48 PS and Sat in the Northeast U.S, 12 (25%) have liquefiers

The Northeast is emphasized because it is the country’s area where local distribution companies (LDCs) are heavily dependent on LNG, as many of these facilities receive LNG via tanker truck from the Everett LNG import terminal.

Origins and Use of Natural Gas

Oil was in high demand in the late 1800s and early to mid-1900s. To the oil drillers' dismay, they often found large deposits of natural gas while drilling for oil. Natural gas at that time was hard to utilize, as there needed to be more gas pipelines for delivering it. Thus, it was often an asset not used as the drillers were looking for oil which was easy to transport by rail, and oil was in high demand. In some places, gas deposits were flared off to get at oil below the gas deposits.

It is a widely accepted belief that both natural gas and oil were formed by organic matter being buried under high pressure and high temperature of rock formations as the earth changed shape over hundreds of millions of years. Some gas production is from porous ground formations where gas extraction is relatively easy. Conventional non-associated gas wells are those that contain only gas. Conventional associated gas wells produce oil and gas. Other gas is found in tight formations such as shale, which needs to be fractured to extract the gas (see Figure 4 below).

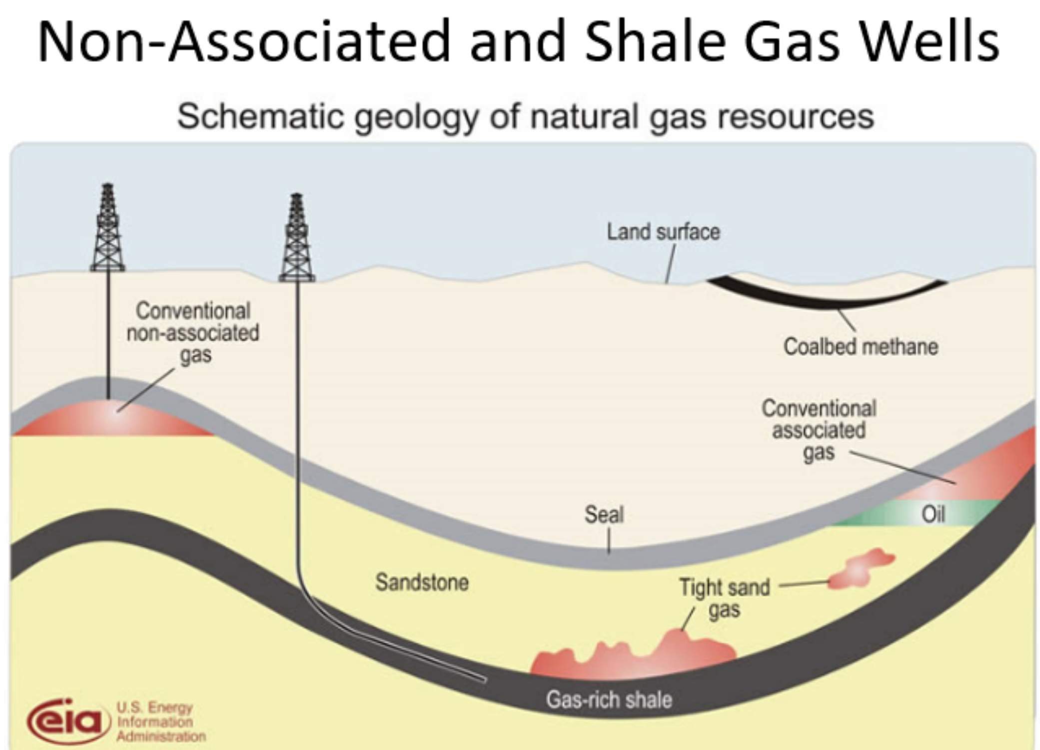

Figure 4: Non-Associated and Shale Gas wells

Source: https://www.eia.gov/todayinenergy/detail.php?id=110

The recent, very productive type of gas production has been shale gas, made possible by directional drilling and high-pressure fracturing with fluids containing poppets (sand particles included in the fluid) pumped into the shale formations. See Figure 5 below.

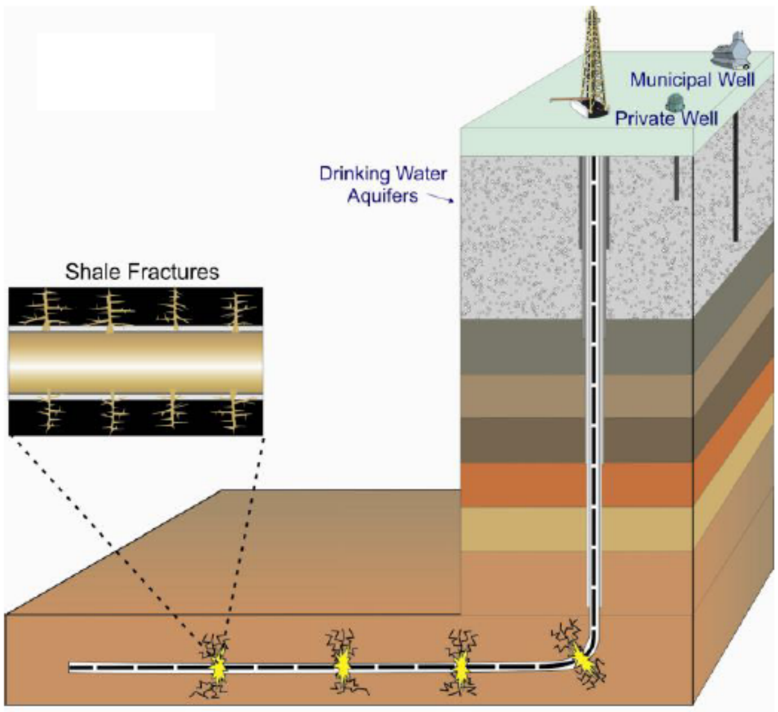

Figure 5: Graphic of the fracture type of well that has resulted in a significant surge in gas production available

Source: www.epa.org

In the early 1900s, in the United States' big cities, manufactured gas was produced to provide fuel for street lighting and cooking stoves. This manufactured gas was typically made from coal, oil, and steam processes. The manufactured gas was poisonous as it contained a significant amount of carbon monoxide.

With so much natural gas being found in Texas, Louisiana, and elsewhere, pipelines started to be installed to sell this natural gas (see Figure 6 below). One by one, the urban centers began to convert from manufactured gas to natural gas. Before sending the natural gas from the wells to the end-users, the natural gas from the wells was processed. This processing included filtering out high-value products such as ethane and propane, and removing much of the water and solids that may have been carried up from the well, along with the natural gas.

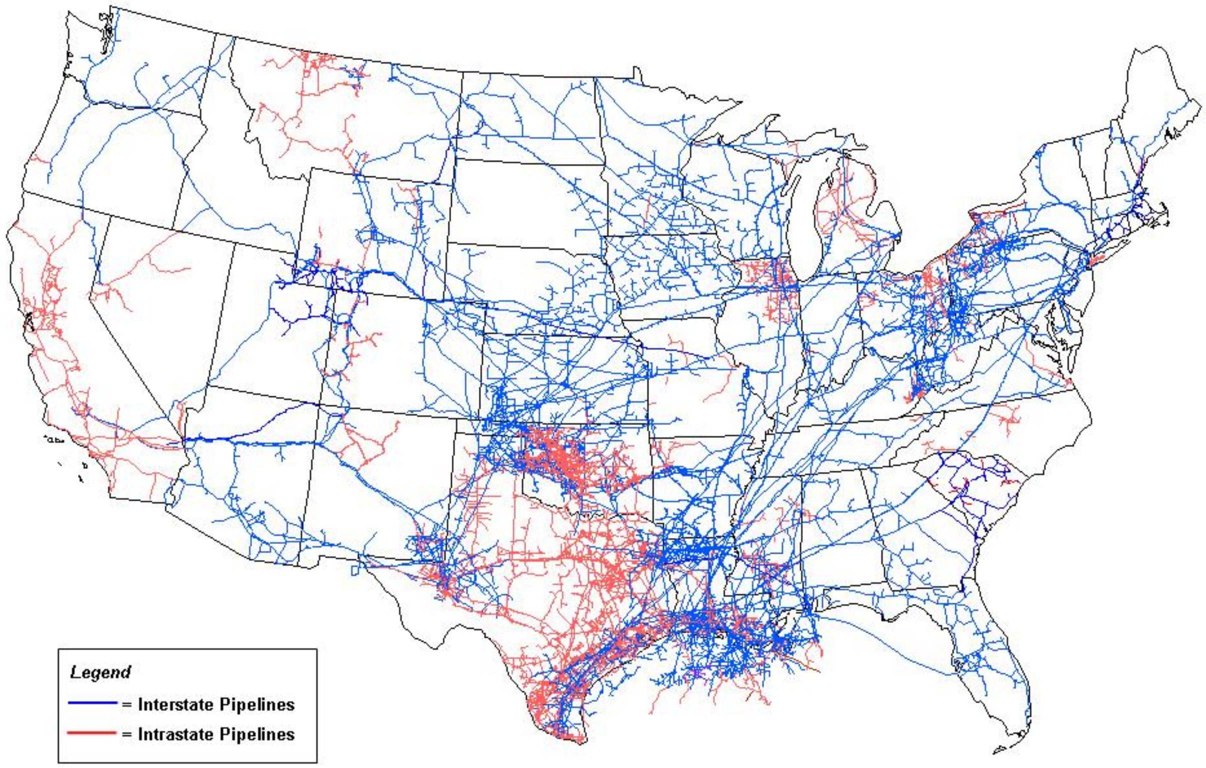

Figure 6: Expansion of Natural Gas Pipelines from production fields to end-use load centers

Source : https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/ngpipelines_map.html

New York City's conversion from manufactured gas to natural gas occurred in the early 1950s. Natural gas had approximately twice the heating value of manufactured gas; therefore, the distribution pipelines could carry much more energy for every cubic foot of gas delivered. It was an excellent time for the gas distribution companies, as many residences converted from coal and oil-burning heating systems to natural gas-burning systems.

Origins and Use of LNG

As mentioned in the introduction, LNG found its first commercial utility in early 1940 when the gas utility in Cleveland used it for peak shaving.

During the coldest days of the year, the demand for natural gas is typically higher than the gas pipeline from the wells can provide. Various means of supplementing the gas shortfall are used. Gas utilities typically contract with underground storage facilities (deleted gas wells that are refilled to be used during times of high demand or salt caverns that are often large artificial holes in large salt formations). However, most underground storage facilities are also far from the local gas distribution companies (LDCs). This is where LNG comes into play.

LNG is a very compact form of natural gas. A cubic foot of LNG produces ~ 600 standard cubic feet (SCF) of natural gas. Thus, a relatively small LNG tank can provide a significant amount of natural gas storage in the LDC's territory. For example, a peak gas demand day may, for an LDC, may require 600,000,000 SCF. If the pipeline taking well-head gas and underground storage gas can only deliver 500,000,000 SCF for that day, then 100,000,000 SCF would need to be vaporized from the LDC's LNG storage tank and injected into the LDCs distribution piping.

It should be noted that the composition of natural gas is different across the country. The composition can change based on what well it comes from and as a result of how much hydrocarbon removal is done for economic reasons (i.e., how much ethane and propane are removed from the gas stream by post-well-head processing). Typically, pipeline natural gas has a heating value of ~ 1035 Btu/SCF (based on higher heating value). A follow-on training session will present the difference between the higher and lower heating values.

Vaporized LNG typically has a slightly higher heating content of ~ 1,080 Btu/SCF. Boil-off gas, predominantly methane, and may have a small amount of nitrogen, can have a heating value of ~ 1,000 to 1,010 Btu/SCF. FERC guidelines and gas purchasing tariffs dictate what heating value and other interchangeability parameters are allowed.

How is LNG Produced

The components of natural gas differ from gas well to gas well, as each deposit formation has a different history. Thus, the feed gas to the LNG production facility differs from LNG plant to LNG plant. Therefore, although each plant needs to be designed to accept its unique range of feed gas, for this training, certain general assumptions can be made, as stated below.

The feed gas to the LNG production facility needs to be pre-treated. This pretreatment needs to include the following:

- Removal of solids (mill scale and grit etc.) and carried along liquids using filters and knock-out drums.
- Reduction of mercury, as mercury attacks aluminum used in heat exchangers in the liquefaction process (typically, if it is reduced, it is reduced to < 10 nanograms/Nm^3 (nanograms per normal cubic meter)).
- Reduction of carbon dioxide (CO_2) to < 50 ppmv (parts per million by volume). This is because CO_2 can freeze and plug up heat exchangers.
- Reduction of hydrogen sulfide (H_2S) to < 5 ppmv. This is because H_2S can freeze and plug up heat exchangers.
- Reduction of heavy hydrocarbons like pentane, benzene, and other hexanes, heptane, and heavier hydrocarbons, because they may freeze and plug up heat exchangers. Each heavy hydrocarbon has an upper limit of concentration.
- Reduction of water vapor to < 1ppmv. This is because water vapor may freeze and plug up heat exchangers.

Mercury is typically removed by the use of an adsorbent or a reactant material in a vessel.

CO_2 is typically removed by the use of an adsorbent or by the use of an amine system
H_2S is typically removed by the use of an adsorbent or by the use of an amine system

Heavy hydrocarbon removal is typically by chilling the gas stream, condensing the heavy hydrocarbons. Typically, additional fractionation of the liquid dropped out is required to separate the lighter from the heavier hydrocarbons further.

Typically, the water is removed by the use of adsorbents.

Once the feed gas is pretreated, the high-pressure treated natural gas is chilled down to a liquid phase at a temperature typically between -180 F and -260 F. The pretreated liquid is then reduced in pressure (through a Joules Thompson valve (JT valve) down to tank storage pressure (typically ~ 1.5 – 2 psig if top filling the LNG storage tank or to the head pressure of the liquid in the LNG storage tank if bottom filling)). This pressure drop results in a Joules-Thompson effect, resulting in a shallow temperature at the outlet of the valve. Just as an example, the inlet of the JT valve may be 100% liquid natural gas at -200 F and 400 psig and the outlet of the JT valve would be a mixture of vapor and liquid and may be at a temperature of -255 F at a pressure of ~ 2 psig (LNG storage tank pressure). The vapor downstream of the JT valve is called flash gas.

The reason the word "may" is used because the actual temperature depends on the composition of the LNG.

The details of the various types of refrigeration systems used to chill the pressurized pre-treated feed-gas will be explained in a follow-on lesson.

As for the composition of the LNG, it will vary from plant to plant, and from feed-gas supply to feed-gas supply. However, a likely composition would be as follows:

- Methane 90+%
- Ethane 4-8%
- Propane < 1.5%
- Nitrogen < 1% but only in newly produced LNG (it will preferentially boil-off the LNG within a short period of time (1-3 weeks)
- Other components in very small to trace amounts.

Characteristics and Properties of LNG

The characteristics and properties of LNG are slightly different for every different composition of LNG. Since LNG is typically 90% or higher methane content, for some of the information below the properties of liquid methane will be used, when describing the characteristics and properties of LNG.

LNG is cold! The saturation temperature of liquid methane ranges from (critical point) ~ -117 F at 663 psia (pounds per square inch absolute) to a temperature of ~ -259 F at 14.73 psia. Because LNG is so cold, when stored, it is continually gaining heat from the environment, regardless of how much insulation is used to lessen the heat gain. Thus, when stored without additional refrigeration, at a fixed absolute pressure, it is always changing phase from a liquid to a vapor. This is called boil-off. In an LNG storage tank boil-off occurs at the surface of the LNG inventory via evaporation of the LNG. It occurs at the surface because at the surface is where there is no liquid head pressure on the LNG. This evaporation results in an auto-refrigeration effect maintaining the LNG at its saturated temperature at the inventory surface. The LNG circulates in the tank resulting in the LNG becoming subcooled when under the liquid inventory head pressure (to be explained further in this training).

Because LNG is so cold, special materials must be used to handle it. Carbon steel would become brittle, and would fail (crack) if it was used to carry LNG. Thus, certain alloys of stainless steel, aluminum, 9% nickel steel and Invar are used to contain LNG.

LNG is a compact form of energy. One cubic foot of LNG when converted to vapor, produces ~ 600 SCF (standard cubic foot) of natural gas vapor.

Unlike natural gas vaporized LNG does not contain significant amounts of carbon dioxide, hydrogen sulfide, heavy hydrocarbons, water or odorant (odorant is removed during the pre-treatment). Since it has no odorant, it is odorless. When, LNG is heated to become a vapor, odorant is added to it before it is sent out for use by natural gas customers.

LNG is a clear liquid and its vapor is clear as well. However, if spilled, its vapor appears like a white cloud because as the cold vapor contacts the air above it, the water vapor in the air condenses producing a bright white water vapor fog.

LNG is not very dense. At atmospheric pressure it has a density of ~ 27 lbm/ft^3 (pounds mass per cubic foot). In comparison, water has a density of ~ 62.4 lbm/ft^3. Thus, it has a specific gravity of LNG is ~ 0.43.

LNG is a mixture of light hydrocarbons, mostly methane (CH_4), some ethane (C_2H_6), a small amount of propane (C_3H_8) and small to trace components of heavier hydrocarbons. Freshly made LNG may also contain some nitrogen (N_2) (typically less than 1%).

As the LNG is stored, the most volatile components preferentially boil-off at a higher rate than the less volatile components. Thus, as it is stored, the nitrogen boils off quickly, and over an extended time, more and more of the methane boils off. As the methane boils off, the LNG becomes richer and richer in ethane and propane. Since ethane and propane have higher heating values than methane, over a period of time, this preferential boiling off, of the more volatile methane, causes the LNG to have a higher and higher heating value. If the heating value is allowed to become too high, the LNG may have a heating value, that is too high to be used interchangeably with natural gas.

Natural gas is lighter than air with a specific gravity of ~0.6. LNG vapors, when warmed to normal atmospheric temperature, is also like natural gas with a similar specific gravity. However, the vapor that comes off of LNG that has spilled, is very cold (~260 F), and thus, has a higher density. The vapors coming off of an LNG spill are heavier than air, and will hug the ground until they warm up (when the density of the boil-off is approximately the same as air at ambient temperature). LNG vapor has the same density as ambient air when the LNG vapor is ~ -170 F.

Hazards of LNG

There are hazards associated with LNG. Some of these are as follows:

It is cold.

Being a cold liquid, it can cause freeze burns if it is splashed on your skin. Extreme exposure as in a burst vessel can cause death. Being cold, it is always absorbing heat from the environment. Thus, one must be sure that LNG is never trapped between 2 closed valves. Wherever the possibility exists for LNG to be locked in between two valves, a thermal expansion relief device is installed in that section of pipe. If LNG were to be trapped between 2 closed valves, without any means of pressure relief, the pressure would increase until the pipe or valve fails.

Also, because LNG is so cold, special materials need to be used to contain the LNG.

Its vapors are flammable.

LNG itself will not burn, but its boil-off vapor is nearly the same as natural gas, and will burn when mixed with the right amount of air. The flammable range for LNG vapor is ~ 5% to 15% gas in air mixture, at atmospheric pressure and temperature. If the mixture is less than ~ 5% gas in air, the mixture is too lean to burn and if the mixture is greater than ~ 15% gas in air, the mixture is too rich to burn.

1. **LNG Spill on ground behavior.** When LNG spills on the ground, a number of phenomena occur. If the spill is from a pipe containing pressurized LNG at saturated conditions, the release will flash into a mixture of vapor and liquid, at the saturated temperature associated with the atmospheric pressure (~ -258 F). The liquid will fall to the ground and the vapor which is heavier than air, when it is very cold, will travel wherever the wind and slope of the ground takes it.

   The liquid being very cold may crack any non-cryogenic materials contacts. In places where there is a potential for spills (around flanges etc.), special precautions are taken to avoid structural damage to critical plant components.

   The liquid spilled will find a low spot on the ground, and collect in a pool. Since the ground is so much warmer than the LNG, it will boil-off very rapidly to a cold vapor.

LNG vapors will deflagrate, and not detonate if ignited, in an open-air environment. However, if the flammable mixture is within a confined space, or a space with a lot of obstructions, like a tightly congested area of pipes and obstacles, detonation is possible.

2. **LNG in contact with water behavior.** If LNG is spilled on water or if water is hose sprayed into a pool of LNG, it can cause a **Rapid Phase Transformation** (RPT). A rapid phase transformation is a mechanical explosion (which is not a combustion explosion). The RPT is a mechanical explosion caused by the rapid heat transfer from the water to the LNG being so high, that the expanding vapor causes a shock wave. This phenomenon does not happen every time water and LNG come in contact, but it has been shown to happen often as the two fluids are put in contact with each other in large quantities.

   It is typical for ice to form when LNG is spilled on water. The water itself does not get contaminated as in a petrochemical spill. After the LNG vaporizes, there is no remaining residue in the water.

3. **Ignition and burning of LNG vapors.** Figure 7 below shows conceptually, on a molecular level, what happens during combustion of methane and oxygen. This reaction will not occur unless the methane and oxygen molecules are: 1. Near each other and 2. Are brought up to the activation energy (temperature) needed to initiate the reaction.

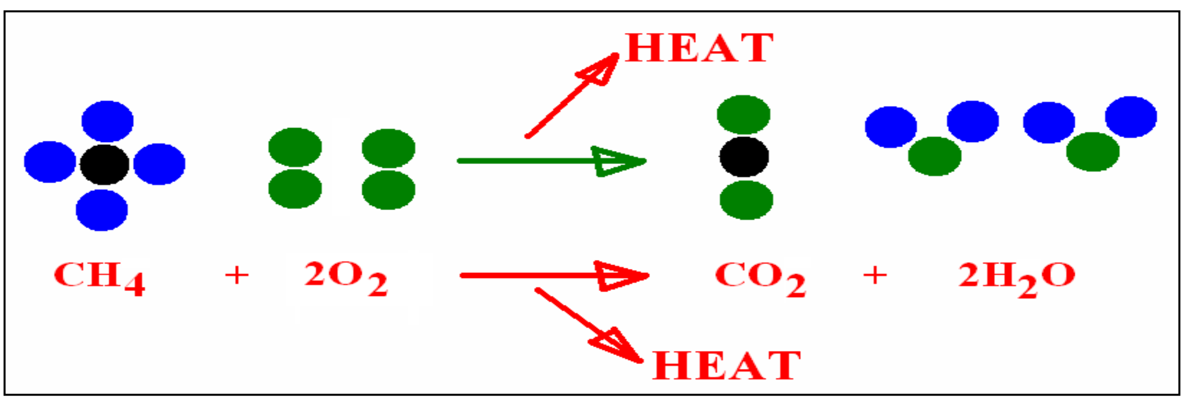

Figure 7: Simplified conceptual graphic showing 1 methane (CH4) molecule reacting with 2 oxygen (O2) molecules to produce 1 CO2 molecule and 2 H2O molecules plus heat.

Source: Self-Made

Each time such a reaction occurs it gives off heat. If there is another set of methane and oxygen molecules nearby, and if the heat released reaches this other set of molecules, with enough energy to have it reach its activation energy, then this set of molecules will also react. If this continues to chain react from sets of molecules to sets of molecules, then a fire will prorogate.

However, if there is too much insulation between the molecule that have reacted and the nearby set of methane and oxygen molecules, the set of molecules receiving, the heat from the first reaction will not reach its activation energy, and a fire won't propagate.

What is the insulation being referred to in the above paragraph? It is too much fuel, or too much air, or an intentionally mixed in inert gas, such as nitrogen. If the mixture of methane in air is too rich (above ~ 15% gas in air (upper explosive limit (UEL)), the excess fuel molecules will insulate the locations, where fuel and oxygen exist, so that they never reach their activation temperature. Thus, the flame will not propagate.

The same holds true if there is too much air in the mixture. If the mixture of methane in air is too lean (below ~ 5% gas in air (lower explosive limit (LEL)) the excess air will insulate the locations where fuel and oxygen exist so that they never reach their activation temperature. Thus, the flame will not propagate.

Figure 8 below, conceptually shows the explosive window for methane in air. Methane is used for this discussion because LNG vapors are a mix of many different gases in varied compositions, but it always has methane, as the highest quantity component (typically above 90% methane).

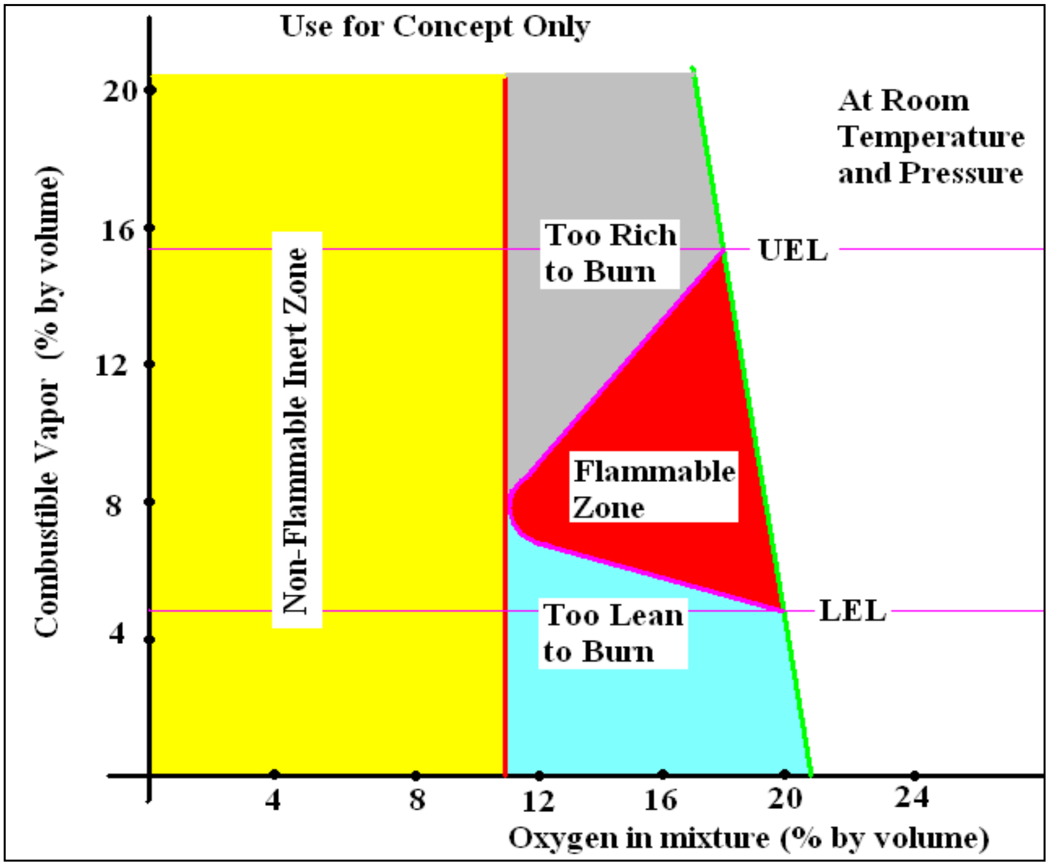

Figure 8: Conceptual graphic to show the flammable zone of methane at various oxygen/methane concentrations at atmospheric conditions.

Source: Self-Made

In the Figure 8, the percent fuel is shown on the Y axis and the percent oxygen is shown on the X axis. Note also that at zero percent methane, the air contains 21% oxygen and as fuel is added, the mixture reduces in the amount of oxygen (follow the green line).

In all of these flammable zone graphics, it is assumed that the mixture is at atmospheric temperature and pressure.

In the Figure 9, it is shown, that if the space considered started out with less than 21% oxygen, the explosive window gets smaller. This would be the case, if a vessel were partially purged out with nitrogen. If there is enough nitrogen added to the space considered, then as gas is brought into the space, the oxygen concentration lessens further and the mixture never passes through the flammable zone. In Figure 9, this is shown as a green arrow.

In the gas industry, it is common practice to drive the oxygen level down to near zero in piping and small vessels before bringing a flammable vapor into the piping or vessels. For very large vessels, bringing the level down to near zero is very difficult, and for such vessels, higher concentrations of oxygen are acceptable. Note: For such applications, it is typical to use the A.G.A. Purging Guidelines to determine the safe oxygen level allowable for gassing in large vessels and tanks (like LNG storage tanks).

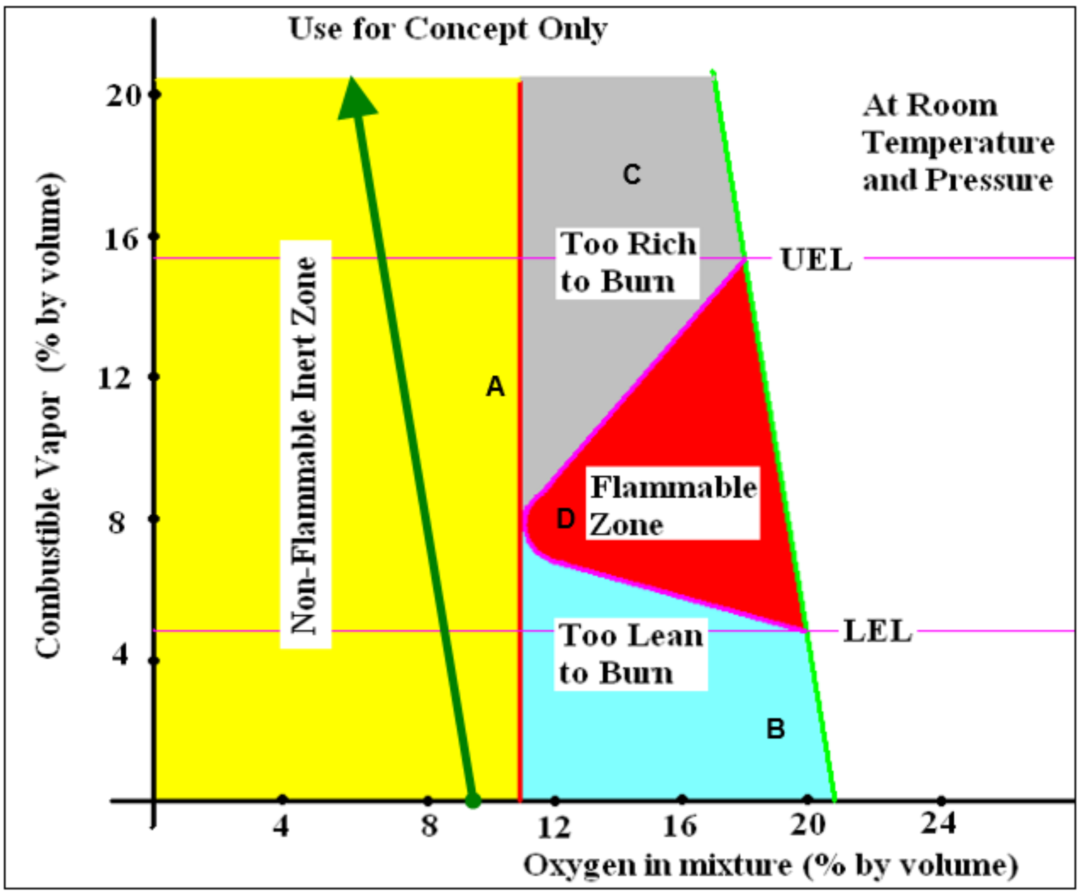

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Figure 9: Conceptual graphic to show the flammable zone of methane, at various oxygen concentrations at atmospheric conditions. When the space is brought down to ~9% oxygen, by purging with nitrogen, prior to injecting methane vapor, the concentration line (shown in dark green) does not pass through the flammable zone.

Source: Self-Made

4. **Purging of vessels.** When purging vessels, care needs to be taken to assure that pockets of oxygen or flammable gas concentrations are indeed reduced to appropriate levels throughout the entire vessel. There are different types of purges shown below (see Figure 10 below).

   Measures need to be taken to prevent channeling during a purge, as a channeled purge will give a false sense of safety, as there will still be high concentrations of flammable gas or oxygen in the parts of the tank, where the channeling has not occurred. Keep in mind, the operator is measuring the outlet gas concentration, to determine if the purge is complete. This is shown in the Figure 11 below.

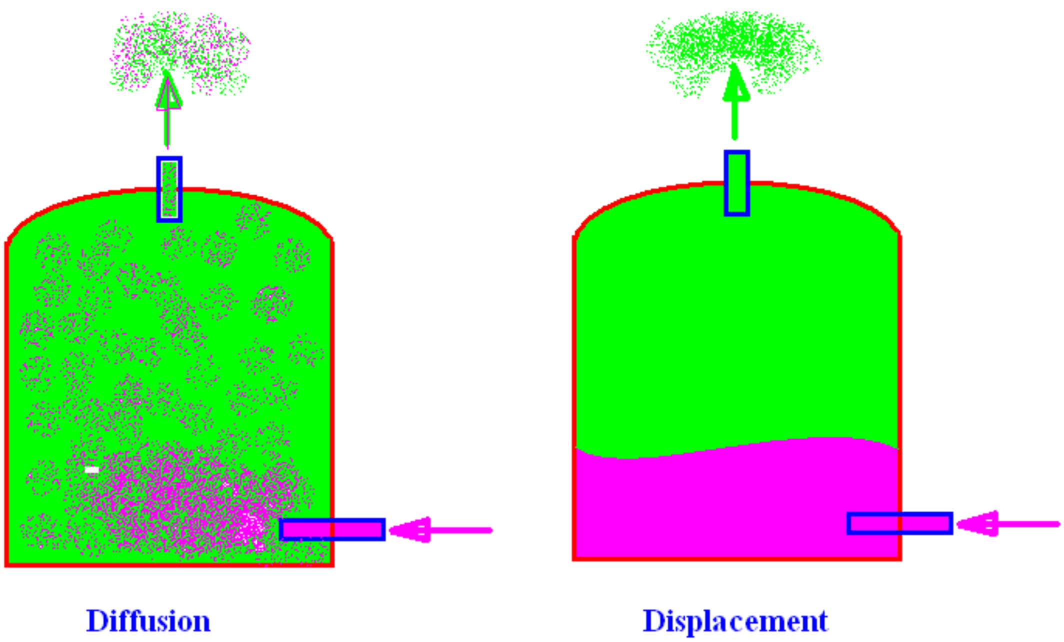

Figure 10: Conceptual view of two different types of purges. In order to get a displacement purge, it is necessary to have the purge gas be of a significantly different density than the gas being purged out of the tank.

Source: Self-Made

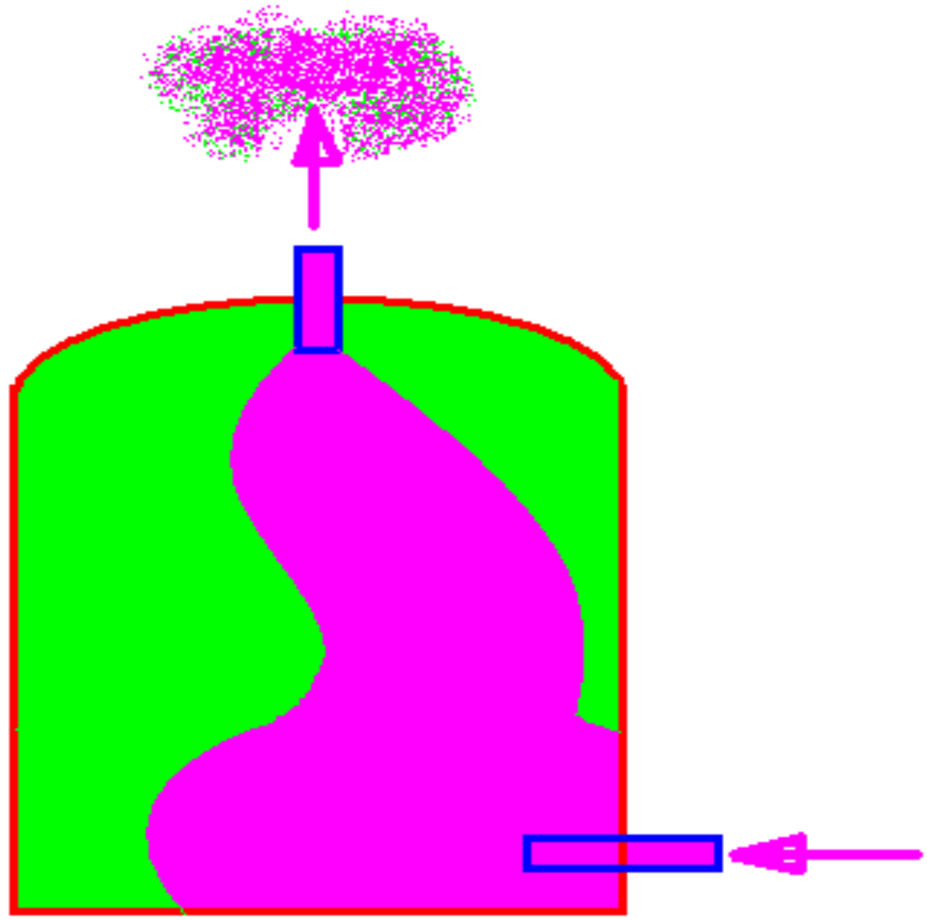

Figure 11: Conceptual drawing a vessel being purged where channeling is occurring. The areas in green show spaces which were not adequately purged.

Source: Self-Made

It is more difficult to purge a vessel that contains a solid adsorbent, a reactant or any powered or granular material. This is because the solid have some tendency to adsorb the flammable gas, and moving the purge gas uniformly through a packed vessel is difficult.

Typically, adsorption occurs at high pressure and low temperatures and desorption occurs at high temperature and low pressure. Take note that the process of capturing gas molecules on a solid surface is an a**d**sorption process and not an a**b**sorption process. Adsorption occurs when molecules are captured in crevices on the surface of a solid, and absorption occurs when molecules go into solution with a liquid. The graphic in

Figure 11 below, conceptually shows how a solid can both adsorb gas molecules on its surface and between the granules, and trap molecules between small powder like particles. Although perlite is not designed to be an adsorbent, it does have a very large surface area with crevasses that can trap gas. In an LNG tank that has been purged and opened, such crevices can out-gas further as the barometric pressure drops.
Thus, fully purging out the annular space of and LNG tank is difficult, first because the purge gas would tend to channel through the fiberglass layer (fiberglass layer yet to be explained in this training), and secondly, because it would be difficult to remove all of the gas, from between or from the surface of the perlite particles.

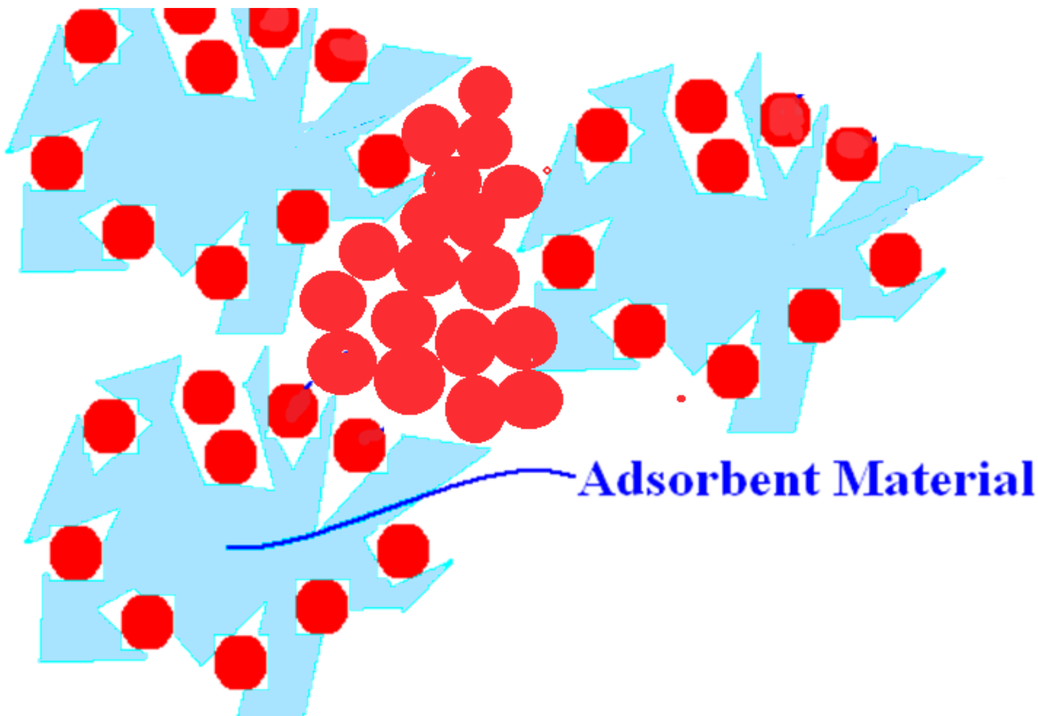

Figure 12: Vessels filled with powered or granular materials are difficult to purge because of channeling and adsorption of the gas molecules on the surface of the materials.

Source: Self-Made.

LNG vapor can be an asphyxiant.

Although the vapors from LNG are non-toxic, they do displace air and displacing air reduces the oxygen content needed for life. Thus, in the same way breathing in nearly pure nitrogen will not sustain life, so too, breathing in nearly pure LNG vapor will not sustain life. Also, because LNG vapors are odorless, the possibility of asphyxiation can come without warning (see Figure 13 below).

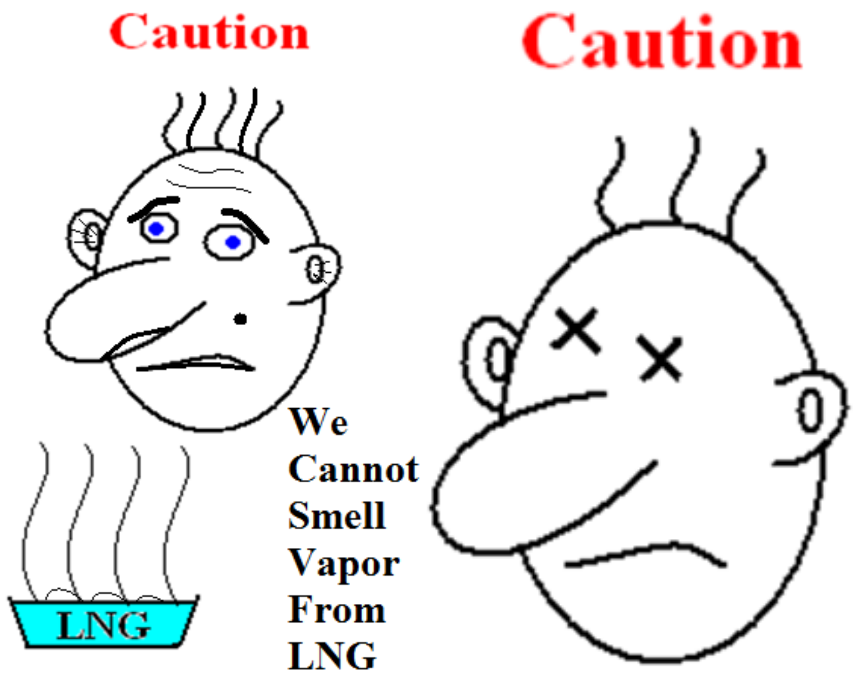

Figure 13: Although LNG vapors are non-toxic, they can displace air which contains oxygen necessary for life

Source: Self-Made

Operational Hazards.

One of the more difficult hazards to avoid is that of human error. Although training programs are in place, and although automatic safety devices are built into the design of the plant, operators need to always be aware of what is technically occurring, while operating the plant.

As an example, when pressure relief valves are serviced, the technician needs to assure, that the valves are operating properly, before putting the system back into service. All procedures, such as, lock-out-tag-out, confined-space work permits, hot-work permits, car-seal procedures and all safety protocols, must be carefully followed.

Also, the operating technicians need to be aware of the “not so obvious phenomena” that can occur. LNG tank stratification and water hammer occurrences, just to name two, can result in significant hazardous conditions. A condensation water hammer is shown in the Figure 14 below.

A condensation water hammer happens when a pressurized line, with a warm leg, is operated at a high pressure, and then depressurizes and repressurizes. When a pump shutdown or some other event causes the pressure to drop, the LNG in the warm leg vaporizes. Then, if the pressure is restored to rapidly, the pressurized LNG rushes to the end of the pipe. When the LNG gets to the end of the pipe, with great momentum, it causes a high-pressure spike, which is called a water hammer. Note, it is common to call this a water hammer, even though it does not involve water!

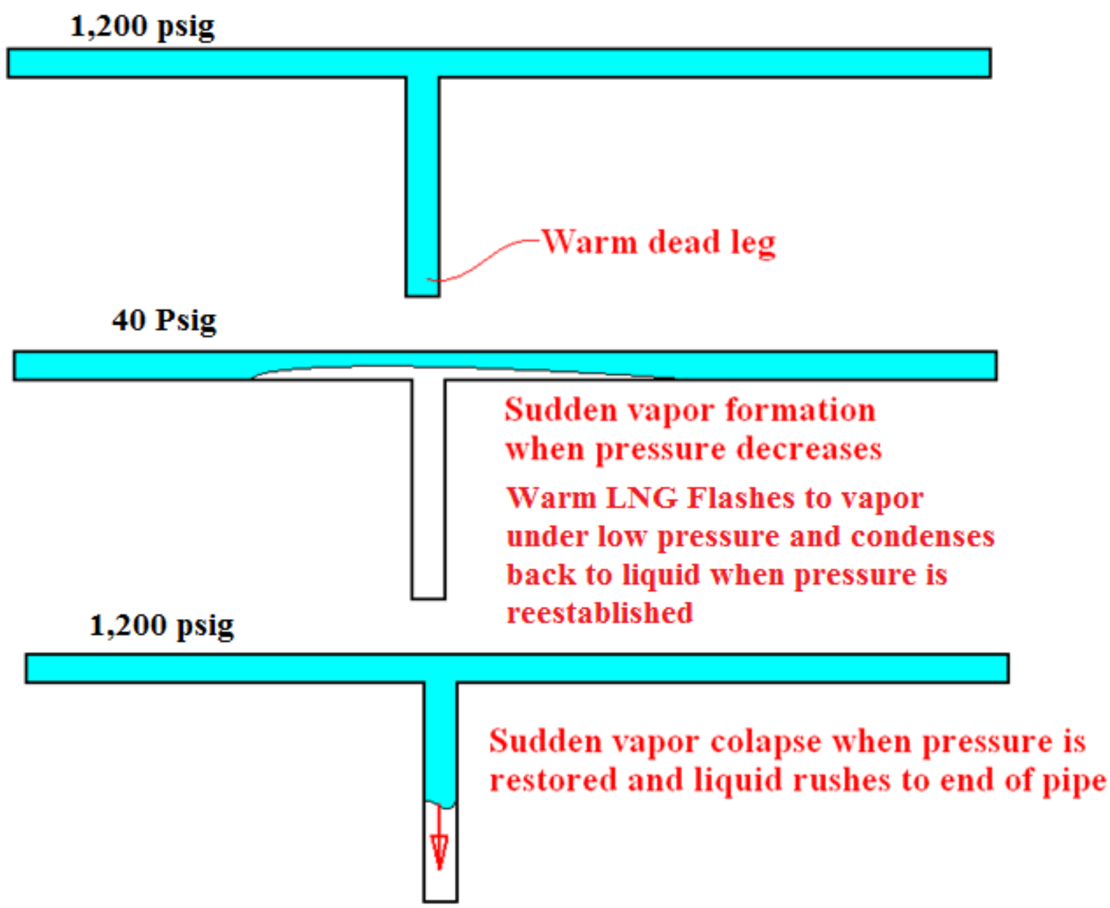

Figure 14: Conceptual graphic of a condensation water hammer

Source: Self-Made

LNG stratification is another avoidable phenomenon, that can be prevented by proper operator awareness and actions. LNG inventory stratification can be either fill induced or nitrogen induced. Whichever the reason for stratification, stratification can lead to an LNG rollover which is hazardous. Stratification is layering of the LNG storage tank inventory, whereby the layers do not mix. Typically, a low-density LNG layer if placed above a denser layer of LNG, or if a dense layer of LNG is placed below a less dense layer of LNG inventory. The layers do not mix but instead circulate within their own strata.

The upper layer remains cold as it continuously evaporates at the surface. The lower layer warms, as heat is added from the environment. There is no way to get rid of that heat entering the lower layer, so the temperature, of that lower layer, warms up. As the lower layer warms, it expands and becomes less dense. Eventually, the lower layer density approaches the same density as the upper layer, and the two layers rapidly mix. This rapid mixing allows the warmed lower layer to rise to the surface where the lower head pressure causes it to rapidly boil-off at a high rate.

Such an event can cause the LNG tank pressure relief valves to release vapor to the atmosphere. In extreme cases, the pressure excursion can exceed the capacity of those relief valves, thereby potentially causing tank damage.

A conceptual rollover is shown, in Figure 15 below, where a layer of liquid methane is placed over a mixture layer of 97% methane and 3% ethane. The methane/ethane layer initially stays in the bottom strata but as it warms its density decreases and eventually it becomes close to the density of the upper layer and that is when the rapid mixing occurs.

6: methane/ethane: Specified state points (0.97/0.03)

	Temperature (°F)	Pressure (psia)	Density (lbm/ft³)	Enthalpy (Btu/lbm)	Entropy (Btu/lbm-°R)
1	-257.50	24.630	26.862	0.44395	0.0018596
2	-255.00	24.630	26.736	2.4833	0.011885
3	-252.00	24.630	26.584	4.9381	0.023792
4	-250.00	24.630	26.481	6.5795	0.031658
5	-247.00	24.630	26.326	9.0490	0.043353
6	-246.60	24.630	26.306	9.3790	0.044903

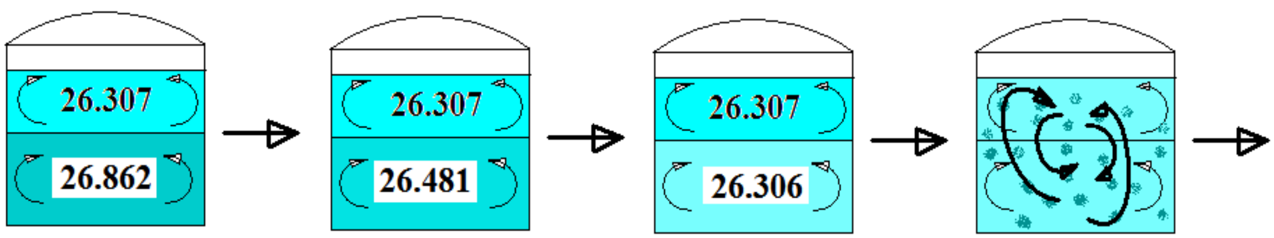

Figure 15: Conceptual data and drawing of a stratification resulting in an LNG inventory rollover

Source: Self-Made

Another conceptual graphic of a rollover is shown in Figure 16 below. It is not really known if the layers flip as shown below or rapidly mix as shown above. However, it is known that the resulting mixing does result in a high boil-off rate, potentially at rates in excess of the relief valve ratings.

In Figure 16, the term weathered LNG is shown. As the bottom layer is heating up and becoming less dense, the upper layer is becoming more-dense as it is preferentially boiling-off its most volatile component, methane. Since, methane is the component with the lowest molecular weight, as the LNG of the top layer lessens in methane content, its density increases. This weathering, resulting in the density increasing, presumes that the initial upper layer of LNG did not contain any nitrogen.

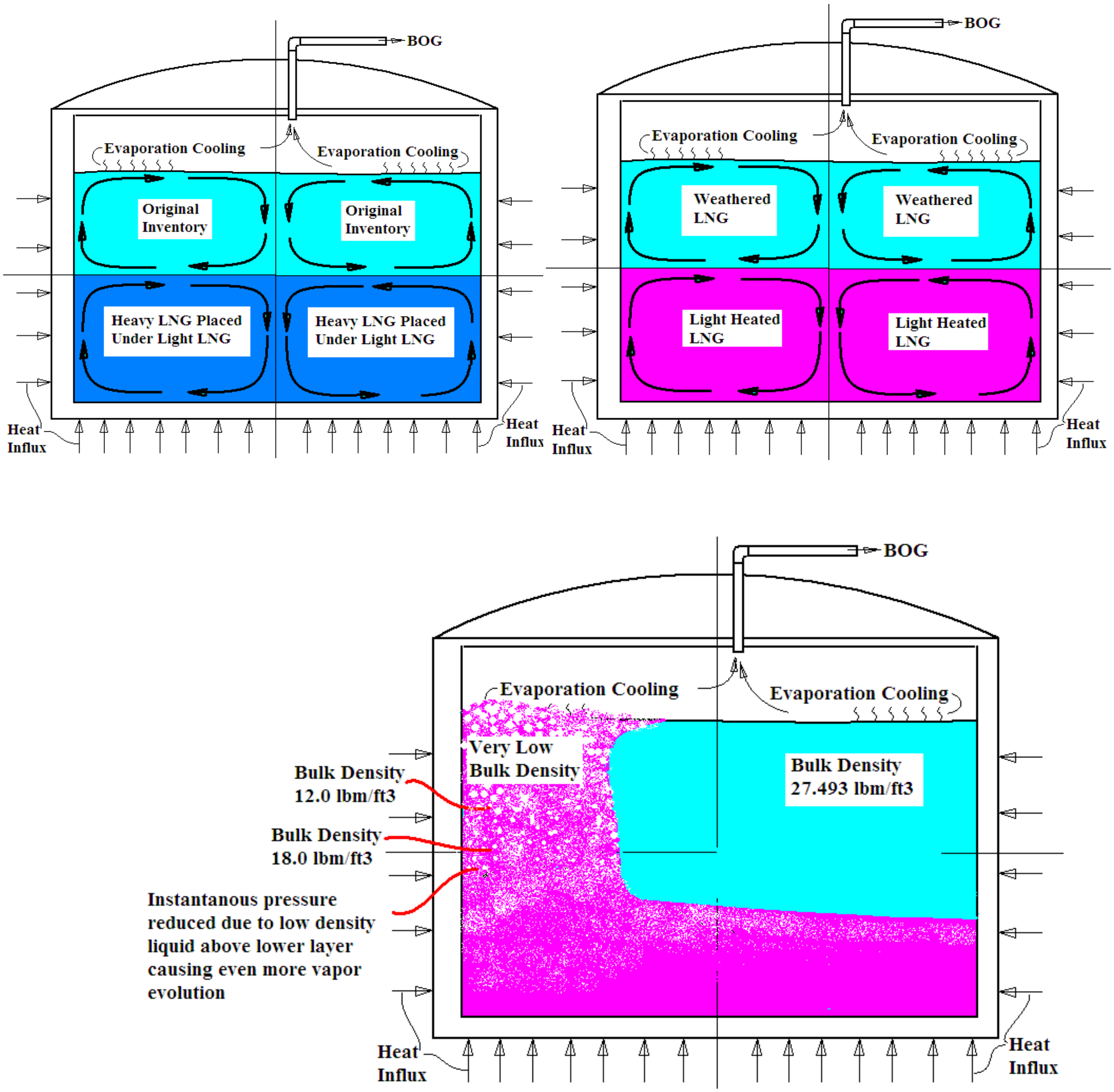

Figure 16: Conceptual graphic of an LNG stratified tank leading to an inventory rollover

Source Self-Made

Typically, a well-mixed LNG tank will not self-stratify unless the LNG has a high nitrogen content. Typically, 1% or greater nitrogen content is considered a precursor to self-stratification.

To avoid having these hazards, personnel handling LNG are highly trained in the management of LNG, and many passive and active hazard mitigation design measures are incorporated in LNG facilities.

Storing LNG

After LNG is produced by pre-treating and then chilling to liquefy it, then it is stored. There are two typically type of storage tanks; ASME tanks and nearly atmospheric pressure tanks. ASME tanks are pressure vessels that typically operate at elevated pressures (typically up to 100 psig (pounds per square gage). The near atmospheric tanks are typically maintained at a pressure of ~ 1 ½ to 2 psig.

For brevity, the below information will pertain only to the near atmospheric tanks. These tanks are large tanks similar to those shown in the below Google earth picture, shown in Figure 17 below. These tanks can range in size from the vaporized equivalent of 100,000,000 SCF to 4,200,000,000 SCF (that is 100 MMSCF to 4.2 BSCF).

Figure 17: Google earth random picture a near atmospheric LNG tank

Source: https://earth.google.com/web/search/Greenpoint,+Brooklyn,+NY/@40.72177969,-73.93139093,26.03674538a,120.30936724d,35y,122.73256523h,44.97545094t,0r/data=CoMBGlkSUwolMHg4OWMyNTk0OGUxZGE1OGIzOjB4NzIwYzg3YjJlOTU0NDU2ZRlZGlMLgF1EQCGEgq1t5XxSwCoYR3JlZW5wb2ludCwgQnJvb2tseW4sIE5ZGAEgASImCiQJFn_PXy8KPkARrUm972QJPkAZxP756mVVV8AheGK6XN5VV8A

In the 1944 Cleveland Ohio LNG accident, LNG from the ruptured tanks entered into the sewer system, which greatly worsened the consequence. Learning from that experience, the codes require a secondary means of impounding the LNG if the primary containment fails.

There are three types of atmospheric LNG tank containments as follows:

1. **Single Containment Tank**. A single containment tank, is constructed with a cryogenic inner tank surrounded by a non-cryogenic outer tank. The outer tank is made of carbon steel, and is there to contain the insulation in place around the inner cryogenic tank. The outer tank is not considered a containment or impoundment because it would fail if it were to be exposed to the cold temperatures of LNG. Figure 17 shows a single containment tank.

   A secondary impoundment (dike or berm) is surrounding the tank, as shown in Figure 18 below. If the first containment fails, the carbon steel tank would also fail and the dike or berm would contain the spilled liquid. With a single containment tank if the inner tank fails, a large amount of vapor would be released as the spilled LNG would spill over the large warm surface area, within the impoundment of the dike or berm. See Figure 18.

2. **Double Containment**. A double containment LNG tank is similar to a single containment tank, except that the secondary LNG containment around the tank is very close to the tank as show in Figure 18. Typically, the secondary containment is made of reinforced concrete. The governing codes detail the distance needed, for an LNG tank, to be considered a double containment tank. With a double containment tank, if the inner tank fails, a lesser amount of vapor would be released as the spilled LNG would spill over a smaller warm surface area. See Figure 18.

3. **Full Containment.** A full containment tank is the most expensive of the three types of tanks. It is essentially a cryogenic tank within a cryogenic tank. Typically, the outer tank is made of pre or post stressed concrete, which typically also has a reinforced concrete roof. With a full containment tank if the inner tank fails, no LNG or vapor would be released as the spilled LNG and its vapor are contained by the outer tank. The outer tank typically has a liner to contain the LNG and vapor inside the concrete. See Figure 18.
   Figure 19 shows 3 full containment tanks.

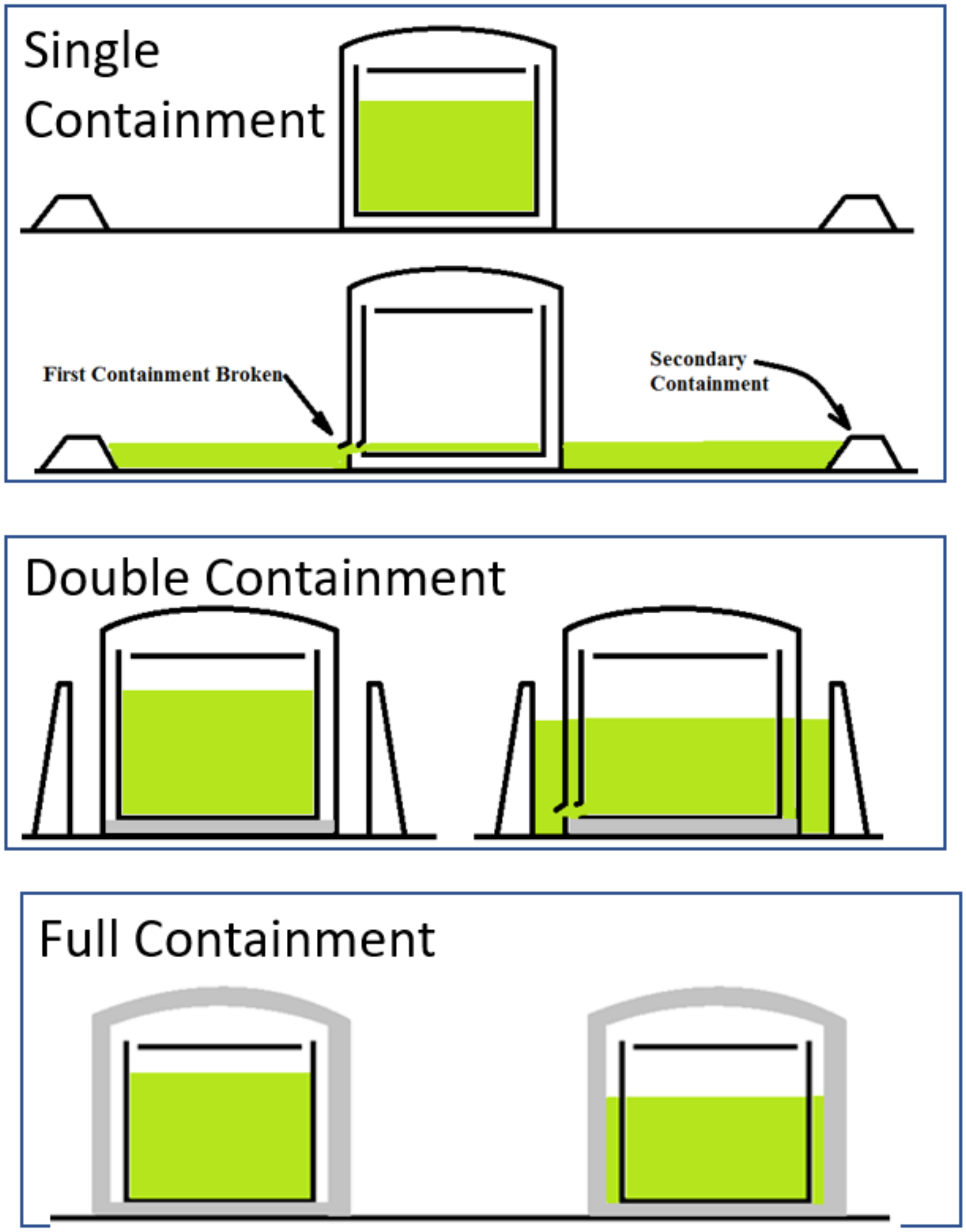

Figure 18: Conceptual graphic of different type of LNG tank containments

Source: Self-Made

Figure 19: Three full containment LNG tanks

Source : https://earth.google.com/web/search/cameron+LNG/@30.03823987,-93.33802117,0.57880222a,512.36883239d,35y,358.3479844h,0t,0r/data=CigiJgokCcY0uw8uozNAEeQRf9wtozPAGf2j822De0VAIRivznKw7UzA

The inner tank material is typically 9% nickel steel or aluminum. It is hydrotested with water before putting it into service. However, the water level is significantly less than the height of the inner tank because water is much more-dense than LNG, and filling the inner tank to the full height would subject the tank to stresses higher than it was designed to support. The welds above the water level are tested by hose spraying the welds. After hydrotesting the tank is dewatered and the space is dehydrated and purged with nitrogen.

After the tank is purged it is filled with boil-off gas. Boil-off gas as is used because it contains essentially no water and or CO_2.

After the tank is filled with BOG then LNG is sprayed into the tank from the top spray nozzles, at a rate that will allow the tank to cool-down slowly and evenly. It is important to assure, that the cool-down is slow and even, to avoid over-stressing the tank material. A sudden surge, of LNG flowing into the tank while the tank is still warm, would be likely to damage the tank, as extreme thermal stresses would occur. During the tank cool-down the tank shrinks in radius by several inches. This is measured during the cooldown to assure that the tank rotational and radial movement is evenly distributed.

When purging, gassing-in and cooling down the LNG tank, care must be taken to avoid damaging the tank. Since the pressures are very low, avoid false readings of the type shown in the Figure 20 below. Also, it is important to never pressurize the annular space to a higher pressure than the inner tank as that could buckle the floor or walls of the inner tank.

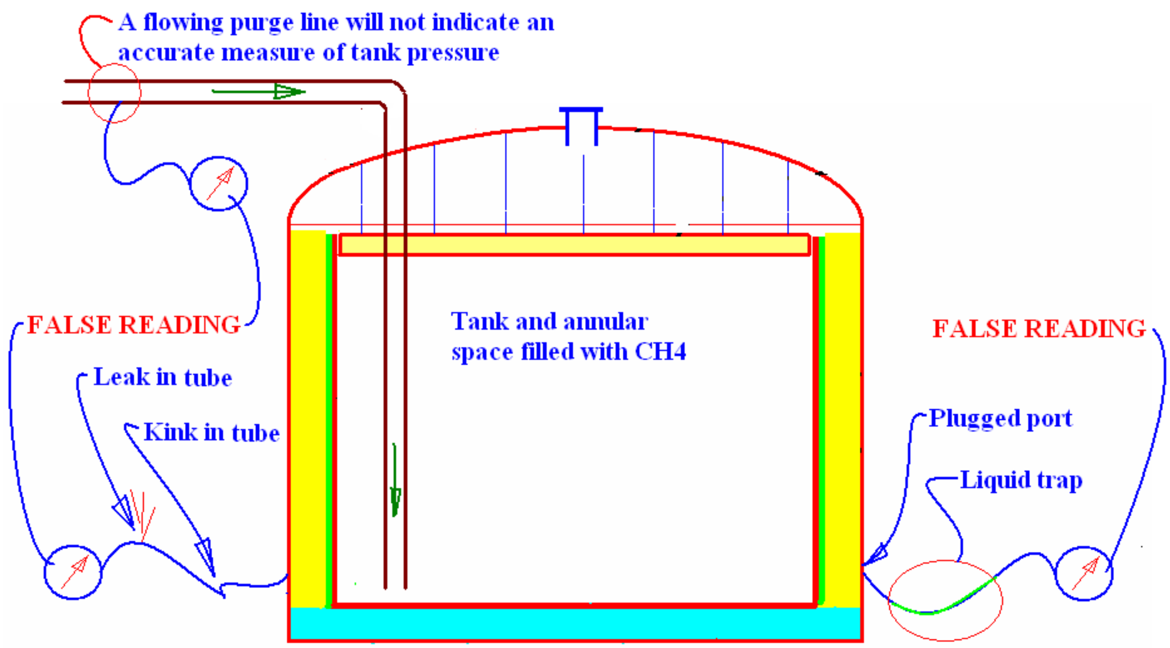

Figure 20: Conceptual graphic - Cautions to beware of when measuring pressures during LNG tank commissioning

Source: Self-Made

When the spraying of the LNG results in a liquid level determined by the tank builder, then bottom filling is typically performed which is followed by top filling. Initially the boil-off is very high as the tank surroundings give up heat to the stored LNG. It takes about a month before the boil-off stabilizes to a constant rate.

The tank is designed to have an annular space between the cryogenic inner container and the outer container. This annular space is filled with insulation. It is typical to have ~ 1 foot of fiberglass insulation directly attached to the inner tank and to have the remainder of the annular space filled with perlite (a power insulation material). The fiberglass insulation is to allow the inner tank to grow, if in the future, the tank ever needs to be warmed up for service. In that case, the fiberglass would crush, as the inner tank expands to its warm state.

Typically, tanks are designed to have an allowable heat leak that would result in 0.05% of the tank inventory boil-off per day (based on a constant tank absolute pressure). If we multiply 365 days times 0.0005, we get 0.18. That means, that an LNG tank just standing idle would lose 18% of its content, just through boil-off each year. More would be lost, if the LNG is pumped and circulated in order to maintain equipment cold.

Keep in mind what was stated earlier, about how the methane would preferentially boil-off first. Thus, if an LNG tank were to remain idle for an extended period of time, the concentration of ethane and propane may become too high resulting in the LNG not being interchangeable with natural gas sendout. Thus, managing the storage of LNG becomes a complex balance between operational needs and gas system needs.

In addition to heat leak, the boil-off gas removal rate from the tank is also affected by barometer and by filling dynamics (flash gas is added to boil-off gas that needs to be removed from the tank during filling).

The barometer is a measure of the localized air pressure. The barometer affects boil-off rates because the tank pressure is actually a differential pressure. That is, whenever you read a gage, that reads in gage pressure, it is actually reading the difference between the atmosphere pressure and the pressure in the vessel to which the gage is attached. If the gage is reading a 600-psig vessel pressure, then a change in atmospheric pressure of ¼ psig would not be noticeable (0.04% of the reading). However, if the gage pressure is reading 1.7 psig, then a change in atmospheric pressure of ¼ psig is significant (15% of the reading).

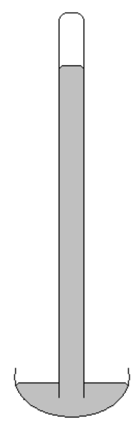

Figure 21: Barometer is a device used to measure the localized pressure of the atmosphere. It is typically a measure of the height of mercury up an evacuated tube.

Source: Self-Made

Thus, if the operator is maintaining the difference between tank pressure as compared to atmosphere pressure at 1.7 psig and the barometer drops by ¼ psig, then the absolute pressure in the LNG tank also drops by ¼ psia. As the tank absolute pressure drops, the boil-off increases and the temperature of the stored LNG decreases to maintain the tank at its new saturation pressure. A similar effect occurs when the barometer increases. As the barometer increases, if the operator maintains the pressure differential between the tank and the atmosphere at 1.7 psig, then the boil-off decreases as the barometer increases.

It is important for the LNG operator to be aware of forecasted barometer changes. For example, if the operator knows a hurricane (hurricanes are associated with low barometer readings) is coming in, then the day before the low barometer pressure, of the hurricane comes in, the operator may want to preemptively lower the LNG tank pressure, to be ready for the hurricane's low barometer. If the operator does not do this, the differential pressure between the LNG tank and the atmosphere may cause the tank's relief valves to discharge, as the boil-off compression capacity of the LNG facility may not be adequate, to remove the boil-off quickly enough.

Near atmospheric LNG storage tanks typically can be rated for up to 4 psig operating pressure, with the relief valve rated to maintain slightly above that pressure. However, many such tanks are rated for lower pressures. It is common for the tanks to be rated at a pressure of ~2 psig with the relief valves rated to maintain slightly above that pressure.

By code LNG tanks must be fitted with both pressure relief and vacuum relief valves. By code, in the U.S., newly constructed LNG tanks must have a relief capacity of 3% of the tank's maximum inventory, boiling-off per day. That is a boil-off of 60 times the normally boil-off rate of 0.05%/day.

Most near atmospheric pressure LNG tanks are placed on a ring wall with a concrete foundation. Because the LNG is so much colder than the ground below it, even with insulation between the ground and the tank, heat needs to be added to the ground, to prevent frost heave from occurring under the tank. Some LNG tanks are placed on piles, and have an air gap between the ground and the concrete slab that supports the tank. These elevated tanks do not require under tank heating elements.

Figures 22 and 23 below, show the tank has heating elements under the tank. These heating elements are typically on line 24/7, to prevent the formation of ice lenses under the tank.

Also, take note that both the outer and inner tank is anchored down to the foundation. This secures the tank in place. Figure 22 also shows the ability to either top or bottom fill. Not all tanks have this ability. Withdrawal is always from the bottom but some tanks only have the capability to bottom fill. A tank with only bottom fill capabilities requires extra operator diligence to avoid stratification as the tank is filled (the operator would not want to place a much denser LNG under a lighter LNG).

Figure 22, shows the outer tank as always being exposed to the tank vapor pressure. This is true with the majority of LNG tanks, but not true with all LNG tanks, as some LNG tanks have a nitrogen annular space with a bladder tank to adjust for barometer changes (bladder tank shown in bottom of Figure 17)).

Figure 22 below, shows that the LNG tank is fitted with (just to mention a few of the components) vacuum safety valves, pressure safety valves, a boil-off gas removal pipe, a top fill line, a bottom fill/withdrawal line with an internal tank valve (ITV). Also shown is a tank tube with and internal pump (note: such a tank would typically not have both a bottom withdrawal line and an internal pump system but have one or the other). Take note that the insulation consists of fiberglass (shown in blue), perlite (shown in orange) and rigid foamglass shown in green.

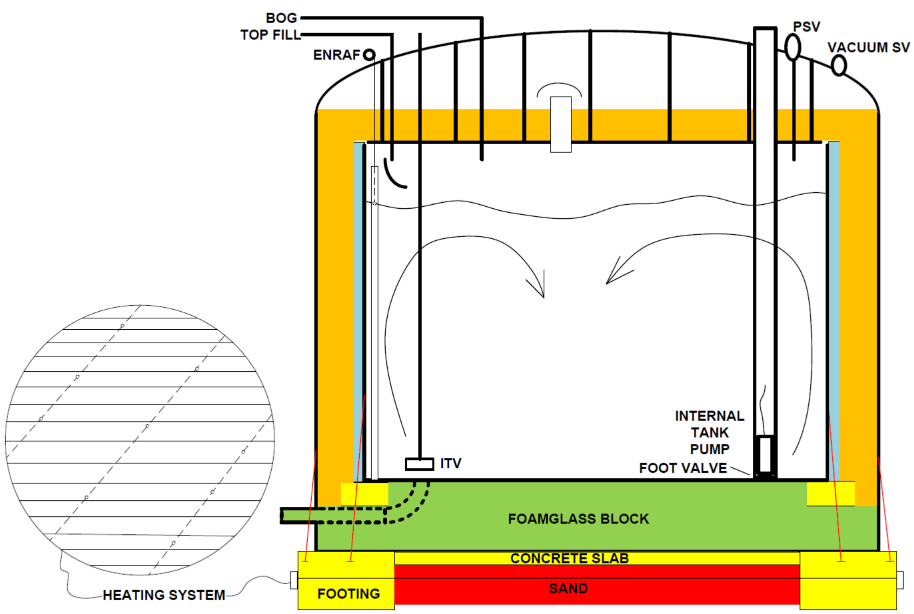

Figure 22: Conceptual graphic showing typical construction of a single containment LNG tank

Source: Self-Made

Figure 23 conceptually shows a closer look at the construction of the tank's connections to the foundation. It is important that the inner tank strap downs allow the inner tank to shrink in diameter, as the tank is cooled down after construction. Because the hold down straps are placed high on the tank, the inner tank movement does not cause excessive stress on the tank wall as it is cooled down.

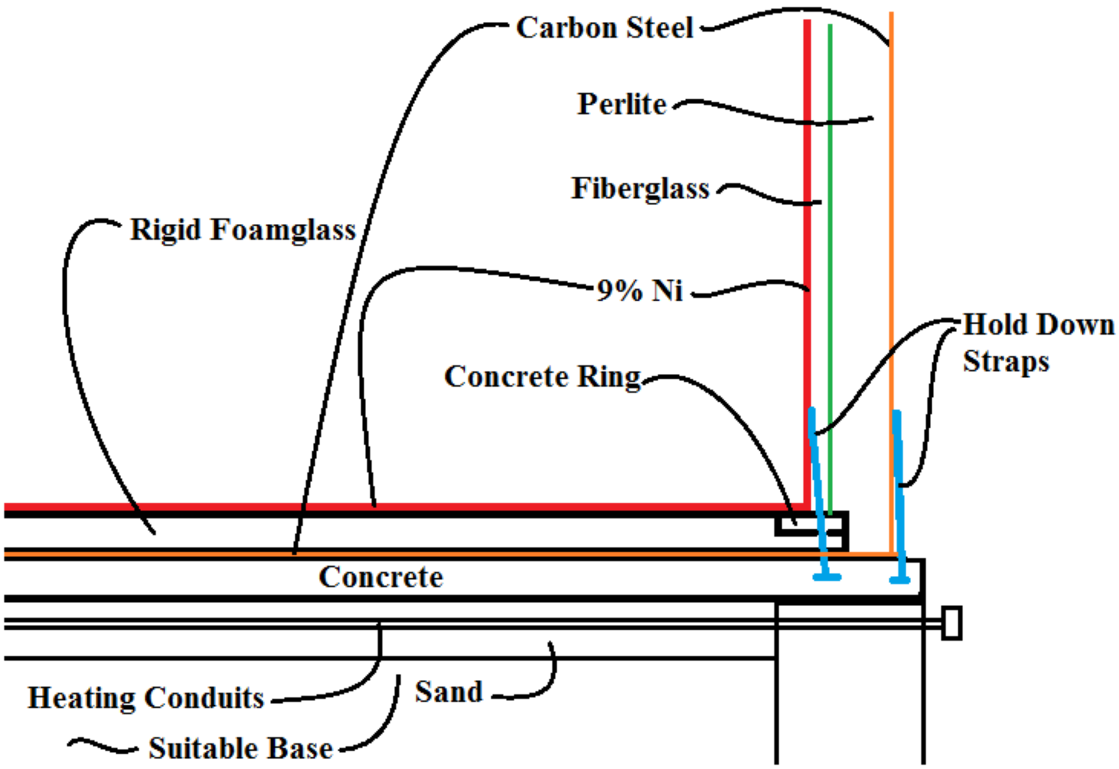

Figure 23: Conceptual graphic showing components of LNG tank bottom edge

Source: Self-Made

Figure 24 shows two full containment tanks, which were to be part of an import terminal. These tanks were never put in service due to public and political opposition.

Figure 24: Two Full Containment LNG tanks that never saw a drop of LNG due to public and political opposition (built in early 70s).

Source Self-Photo from street

Figure 25 below, shows how a non-stratified tank circulates its inventory. This movement is very important for a host of reasons. This circulation is caused by natural convection. The slightly warmer LNG at the sides of the tank becomes less dense, as it expands due to slight warming, and it rises to the top of the tank. When the rising LNG, along the inner tank wall, reaches the surface of the inventory, it is no longer under a head of liquid pressure, and some of the LNG evaproates resulting in a cooling effect. This cooling makes that LNG slightly denser. The slightly denser LNG moves to the center top of the tank, and then drops to the bottom of the tank. This convective action results in the circulation shown in Figure 25.

What makes this very important is that it prevents stratification and subsequent rollover. Further, this circulation causes the temperature at the top of the tank to be nearly the same as the temperature at the bottom of the tank. This results in the LNG, at the surface of the inventory, being a “saturated liquid (at its boiling point)”, and the liquid at the bottom of the tank being a “subcooled liquid (due to the head pressure it is below its boiling point)”. This is critical for pumping the LNG.

As seen in Figure 22, whether the LNG is drawn out of the tank from, a bottom tank penetration, or is pumped via a pump in a tube, at the bottom of the tank, the LNG is always from the bottom and thus is always subcooled.

It is essential that the LNG being fed to the LNG pumps always be subcooled, because the pressure drop, at the inlet of the pump, would cause the LNG flash, to vapor, if it was not subcooled. Bubbles of vapor in the pump can destroy the pump for a host of reasons. Some of those reasons is that the LNG pumps use the LNG as the lubricant for bearings, to flood close tollerance seals and to cool submerged electric motors.

Bubbles in the pumps can also cause cavitation and a loss of output pressure produced by the pump. This loss of outlet pressure can self worsen and seige the pump. Also, as the pump outlet pressure drops, other pumps on line may push the lower pressure pump off line.

To avoid being pushed off line, and experiencing a no flow condition, LNG pumps are equipped with a recycle circuit, that returns LNG to the tank. However, returning LNG back to the tank is very inefficient as the energy of pumping the LNG results in a higher boil-off rate. Thus, recycling back to the tank is typically avoided, unless tank pressures require additional boil-off, due to a rapidly rising barometer, or due to a very significant liquid withdrawal rate.

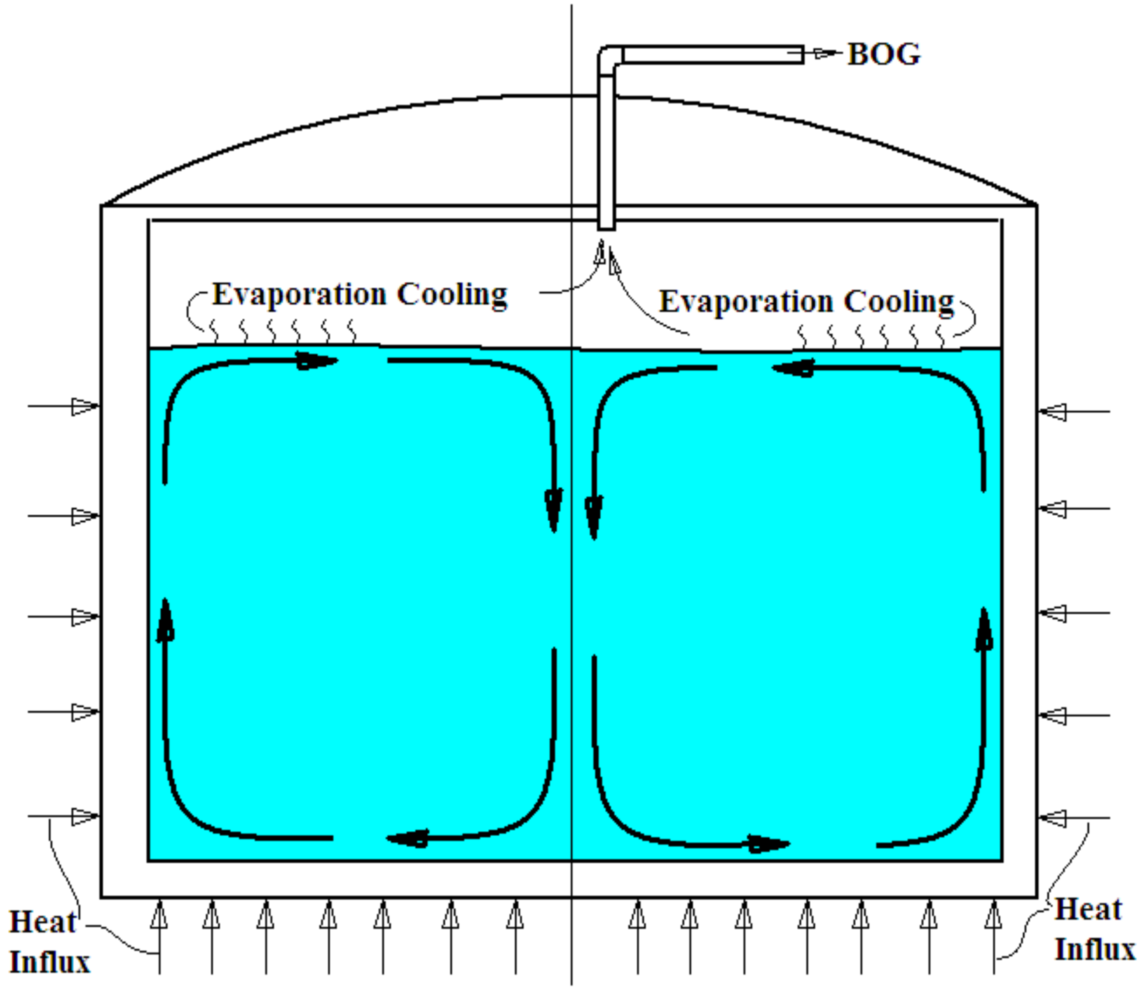

Figure 25: It is critically important that the tank retain its natural convection circulation.

Source: Self-Made

Another method of storing LNG is via ASME pressure vessels. This will be discussed in a follow-on training session.

Transporting LNG

Transporting LNG short distances as from one end of the plant to another is performed using highly insulated pipes.

Pipes like tanks need to be cooled down carefully, to not over thermal stress the piping. Small piping (under 12” in diameter) is sometime allowed to cool by weeping LNG into the pipe slowly. The vapor that is produced travels down the pipe pre-cooling the piping that has yet to be cooled by the liquid LNG, until eventually the piping is totally cooled down. Rapid LNG cooldown is also allowed for small diameter piping.

Large diameter piping (12” and over) is typically cooled down by passing cold boil-off gas through the pipe first, to a temperature of ~ -180 F, before LNG is introduced. If LNG is allowed to enter a large diameter pipe before cooling it down, the bottom of the pipe would shrink before the top does, and the pipe can bow, and may even move off the pipe rack. Further, the thermal stresses may be outside the allowable range for that piping if the pre-cooling were not performed first.

All LNG piping must be designed for pipe shrinkage and growth via using expansion joints or piping loops. LNG operators must make sure that sliding supports are free to move, and that spring hangers are properly calibrated.

Transporting LNG many miles, say from one state to another is typically performed by LNG tanker trucks. LNG tanker trucks are typically made, with an inner tank of stainless steel or aluminum, and an outer tank of carbon steel. The annular space is typically evacuated, to eliminate convection heat transfer, and it is typical for the inner tank, to be wrapped with reflective layers, to reduce heat transfer into the tank via thermal radiation. This combination of vacuum and reflective layers is often called super-insulation. A typical LNG tanker truck will hold approximately 10,000 gallons of LNG. Each gallon of LNG produces 80 SCF. Thus, each tanker truck holds the equivalent of approximately 800,000 SCF. It would take ~ 1,250 tanker trucks to fill a 1 BCF LNG tank, not accounting for flash gas losses.

The practical distance to transport LNG via tanker truck is a maximum of ~ 1,200 miles (not a hard rule just my informed opinion). Transferring LNG for distances beyond 1,200 miles is possible, but becomes economically less practical. During the tanker transport, mechanical work (viscous dissipation) is put into the LNG, by vibration and sloshing. This mechanical work along with heat transfer into the LNG may result in the driver needing to vent-off boil-off gas during a long truck transport.

A tanker truck transport route may have the truck leave the tanker fill station with 20 psig and cold LNG in the tanker truck, and it may arrive, at the drop off location with 50 psig warmer LNG in the tanker truck. When the tanker truck arrives at its delivery location the LNG is warmer based on the saturation pressure of 50 psig. This warmer LNG results in additional flash gas produced as the truck offloads its LNG to the receiving LNG tank.

Transporting LNG via ship transport is viable for long distances, and large volumes of LNG. LNG tankers are typically ~ 148,000 m^3 in cargo capacity (normally 150,000 m^3). However, there are ships of different sizes the largest of which is ~ 290,000 m^3.

The typical loading and unloading rate for an LNG tanker ship is ~ 12,000 m^3/hr. Typically, the loading/unloading is performed using 3 LNG loading/unloading arms and 1 vapor loading/unloading arm. These arms are articulating, to move as the ship rises or moves in the water. Typically, the movement is very slight as the ship adjusts ballast to account for the amount of LNG inventory on the ship.

There are 3 types of LNG transport ships; the free-standing spherical type of ship, which has large aluminum spheres on the ship to hold the LNG, the membrane ship that uses a ship internal structure to support the cargo containers, with the cargo containment made by a special designed metal membrane and the free-standing prismatic type B LNG tank ship. These ships typically have 4 – 5 tanks on each ship. Each tank is typically equipped with 2 discharge pumps and one smaller pump which is used to spray the tank walls with LNG to keep them cold after the ship has offloaded its cargo. It is typical that the ship cargo containers are never fully emptied unless the ship needs to go into dry-dock for repairs. Always maintaining some level of LNG in the tank avoids thermal cycling of the tank.

To give you an idea of how much LNG 150,000 m^3 of LNG is, follow the math.
150,000 m^3 x ~35.3 cu.ft./m^3 = 5,295,000 cu.ft. of LNG. Each cubic foot of LNG contains ~7.48 gallons. Thus, the number of gallons contained in 5,295,000 cu.ft. of LNG is 39,606,600 gallons. Each gallon of LNG vaporizes to ~80 SCF of vapor. Thus, 39,606,600 gallons of LNG produces ~ 3,168,528,000 SCF (3.17 BSCF). Consider a 1,000,000-barrel LNG tank at LNG import/export terminal. 1,000,000 barrels is 42 million gallons which equates to ~ 3.36 BSCF. With this size tank, one 150,000 m^3 ship nearly fills the LNG tank. Keep in mind, the land-

based LNG tank is never allowed to be drawn down to empty because it would warm up and this is typically never done in the life of a tank unless it needs to be taken out of service.

It is typical for LNG import/export terminals to have more than one tank, however, some receiving facilities have only one tank at the location. Terminals with only one tank need to schedule their usage and ship arrival events carefully, to make sure they do not run low on LNG for end-use, before the next ship arrives, and that there is enough room in the in the land-based LNG tank to accept a full ship of LNG. It is not common for an LNG tanker to make partial shipload deliveries for a host of reasons including potential damage to the ship's cargo tanks.

Re-gasifying LNG

To make LNG back into a vapor, to be injected into the pipeline; to supply customers, LNG is pumped to LNG vaporizers. Vaporizers add heat to the LNG. The amount of heat needed to re-gasify LNG is equivalent to ~ 1.5%, of the heating value, of the LNG being vaporized.
Re-gasifying LNG is performed by passing the LNG through a heat exchanger to convert the LNG to a vapor and to then bring it to a warm enough temperature to be injected into the natural gas pipeline. The final sendout temperature is typically ~40 F.

There are many types of vaporizers. Some of them are as listed below:

Submerged Combustion Vaporizer

A submerged combustion vaporizer bubbles up hot products of combustion through a water bath keeping the water bath at a temperature of ~ 100 F. The bubbles create a large amount of turbulence, which results in a high heat transfer, to the LNG tubes within the water bath. The LNG flows through the LNG tubes, which are in the water bath, where the LNG is vaporized and warmed.
It has been challenging to get the water bath vaporizer to meet emission requirements in certain non-attainment parts of the country. The submerged combustion vaporizers are very efficient, as the combustion products are brought way down in temperature, condensing the water vapor out of the products of combustion. Since the water vapor, from the products of combustion, is condensed, the submerged combustion vaporizers, produce excess water which is acidic and typically needs the pH to be neutralized before discharging it. This acidic water also makes corrosion control challenging.

Falling Film Vaporizer

Falling film vaporizers use a vertical heat exchange panel, with warm water flowing outside the heat exchanger panels. Falling film vaporizers are often used in area where there is plenty of warm ocean water available. The positive point of using warm seawater is that the vaporizer does not require the burning of fuel. On the downside, a large amount of sea water must be pumped, and there is an ecological harm that occurs as some sea life gets caught in the strainers, and as colder water is returned to the ocean.

Direct fired Vaporizer.

Direct fired vaporizers are not a popular in recent decades but were popular back in the 1960s and 70s. Direct fired vaporizers are heat exchangers that have finned tubes in a firebox cabin where burners are used to heat the firebox cabin. Thus, on one side of the heat exchanger tube there is very cold LNG and on the other, there is the very hot products of combustion. A mis-operation of the unit during start up, can cause the stainless-steel tubes overheat and sensitize, resulting in a grain boundary corrosion tube failure.

Indirect Water-Bath Heater Vaporizers.

Indirect water-bath heater vaporizers are water heaters, that heat water via a fire tube type of boiler. However, in the very same water bath are also tubes carrying LNG. Typically, instead of using water, an ethylene glycol or propylene glycol and water mixture is used as the heat transfer medium.

Remote Fired Heat Exchange Vaporizer.

In this type of vaporizer, a heat exchanger is located far away from the fired burner needed to make the hot heat transfer medium, and pumps are used to circulate the hot heat transfer medium. Typically, instead of using water, an ethylene glycol or propylene glycol and water mixture is used as the heat transfer medium. With this type of vaporizer, some operators have chosen to locate the heat exchanger within the LNG tank dike impoundment area. This restricts all the flowing LNG, to within one impoundment area, where the LNG tank, LNG pumps, and heat exchange vaporizer are all within the dike containment of a single containment tank. This eliminates having any combustion sources of ignition being near the flowing LNG.

There are other types of vaporizers, but they all have the same mission, the transfer heat to the LNG to change its phase from a liquid to a vapor and to send it out as a warmed vapor at ~ 40F. It needs to be realized that changing phase occurs only as long as the LNG pressure is less than the LNG critical point pressure. Above the critical point pressure of the LNG there is no liquid or vapor phase, the LNG would be just a fluid, that would need to be heated to ~ 40 F for sendout.

In plants that do a large amount of vaporizing each year, it is often economically beneficial to incorporate a re-condenser, into the sendout system. A re-condenser uses subcooled LNG to condense boil-off gas. The subcooled LNG is made by pumping LNG to a higher pressure. The boil-off gas needs to be compressed to a higher pressure to be injected into the re-condenser. The subcooled LNG extracts heat from the boil-off gas, condensing the boil-off gas into a liquid. The resulting liquid from the initially subcooled LNG, and condensed LNG, is then pumped to the vaporizers. It is important to note, that a re-condenser can be used ONLY when vaporization is in progress, because the re-condenser will not work, unless the outlet

LNG is being sent to a vaporizer. Figure 26 below, is a conceptual graphic of a re-condenser (these are also sometimes called condensers).

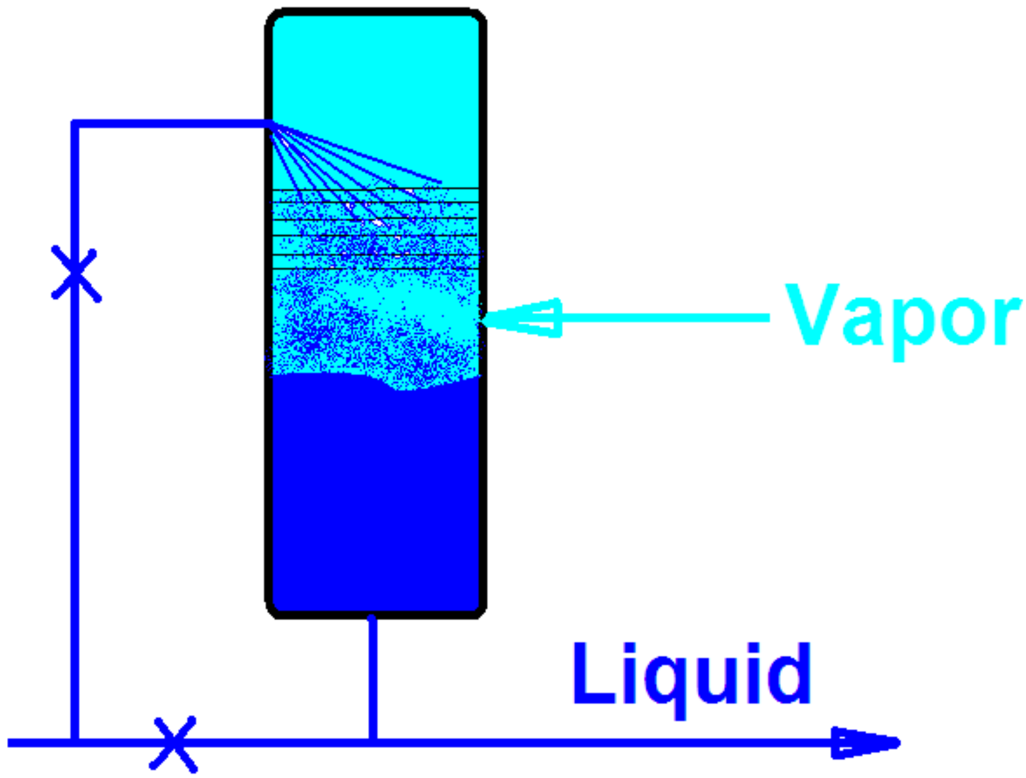

Figure 26: Re-condenser using subcooled LNG to condense boil-off vapor. The liquid leaving the re-condenser is sent to be vaporized.

Source: Self-Made

In any vaporization system it is critically important for the sendout temperature to be monitored closely and for automatic emergency shutdowns to be in place in the event the sendout becomes too hot or too cold. If the sendout becomes too hot, it could damage the sendout piping coating. If the sendout becomes too cold, it could crack the non-cryogenic sendout piping.

Plant Safety and Reliability (short version)

The most important topic to be covered would be LNG plant safety. Since safety is itself the most important topic, a stand alone training module will be given, in the future, on LNG plant safety.

However, a few topics will be covered here-in to highlight just a few of the safety measures taken in an LNG facility.

A full 3.36 BSCF tank contains enough energy, to run a 125,000 Btu input home heating , 24 hrs. a day, 7 days a week, for over 3,000 years. That is a lot of energy. Here are a few of the safety issues that are to be considered.

The design, operation and maintenance, of the LNG facilities, in the U.S., that are under FERC juristiction, must, at the very minimum, meet the safety requirements of the codes 49CFR193 and NFPA 59A. These codes also reference many other codes, that must be followed.
One of the most important requirements is that the workforce is adaquately trained, to develop a **Culture of Safety and Reliability**. This culture embraces:

- Making sure the plant is designed properly by performing many process safety analyzes (PSA) including:
    - A hazard identification study (HAZID)
    - A hazard and operability study (HAZOP)
    - A layers of protection analysis (LOPA)
    - Peer review of final design (typically, the owner's representative will do this review)
- Following "well developed" precedures
- Not implementing changes in the plant, unless they have been rigorously "Management of Change" proven to be safe and acceptable

Every employee needs to be adequately trained, both in classroom, and in the plant itself. A curriculum needs to be developed, that meets code requirements, and that promotes a culture, of safe operations and maintenance.

In addition, refresher training is critical to assure, that every employee is competent, in the performance of his/her job duties and in emergency procedures. Training also needs to include recognizing abnormal operating parameters, such as lower than normal boil-off rates (an indicator of stratification), unusual pipe movement (many different causes and requires investigation), abnormal trends in the measured parameters, and any visual anomalies.

Reliability by redundancy of equipment

Having 3 smaller pumps plus a spare pump, instead of one large pump makes the ability, to vaporize more reliable. However, this needs to be analyzed, to assure that the is no other single failure point for the 4 pumps. I.e., if all 4 pumps are supplied with electric power from the same sub-station, then having multiple pumps does not prevent a single event, at the sub-station, from shutting down all vaporization capability.

Proper maintenance of equipment.

Condition monitoring is encouraged including tribology, vibration sensing and thermography. The studying of trends is important, as are regular programs required by codes and observing best practices. Routine monitoring and testing of the physical plant equipment is critical. Such routing monitoring/testing includes but is not limited to:

- Routine relief valve testing
- Routine spring hanger evaluation
- Inspecting sliding supports
- Inspecting insulation
- Inspecting safety systems
- Gas detectors
- Flame detectors
- Cold sensing detectors
- Emergency shutdown systems
- Performing emergency drills
- Operating emergency generators to assure they automatically will provide the needed electricity when called upon
- Testing Uninterruptable Power Supplies (in particular batteries must be maintained)
- Assuring compressed is properly dry
- Inspecting and to the extent practical testing fire extinguishing equipment
- Testing the fire water systems

The culture of safety and reliability

The culture of safety and reliability develops personnel, that value, and are rewarded, for preemptive thinking, to avoid accidents. Such a culture, promotes continuous learning, continuous improvement, and ethical behavior, which avoids taking unreasonable risks. This culture also learns, from events that have occurred in, the gas and LNG industry, as well as events that have happened in other industries. For example, there are many cross-cutting procedures that are in place, not only in the petrochemical industry, but in other industries, to assure safe operation. A few examples are shown below:

- Lock out tag out procedures
- Car-seal procedures
- Work permits
- Hot work permits
- Confined space entry permits
- Safety meetings
- Safety audits conducted by an independent evaluator

Programs are also important. Some safety and good business practice programs include, but are not limited to the following:

- Crisis Management Program including table top and on-site drills (explosion at plant, shooting at plant, contamination at plant, terrorism threat at plant, equipment failures, etc.)
- Succession plan for critical personnel
- Training plan
- Maintenance plan
- Procedure update and distribution plan

Auxiliary Systems

In order to operate an LNG facility, a host of auxiliary systems need to be provided.
One of the more difficult products to manage is boil-off gas. Managing boil-off is a 24 hr./day, 7day/wk. 365 day/yr. activity. As long as there is LNG in the plant, heat is leaking into that LNG and subsequent boil-off is being produced.

Boil-off gas is cold, and requires a significant amount of energy to compress, from tank pressure to pipeline pressure. Further, the production of boil-off gas varies, depending on barometer, and plant activities. Because it is cold, it needs to be compressed via cryogenic compressors, or by heating it first, and then compressing it using non-cryogenic compressors. It is quite common to heat the boil-off gas before compression. Such compression relies on auxiliary systems (electric supply, control systems, heating systems, cooling systems etc.).

Because the inability to compress boil-off gas would result in the need to vent the boil-off gas to the atmosphere, it is critically important to assure that boil-off management devices are redundant and that the power supply to them is also redundant. The boil-off system is just given as one example, of many systems that required redundancy and assurance of operability.

Auxiliaries needed to operate an LNG plant include but are not limited to:

- Electric power supplies
- Emergency power supplies
- Uninterruptable power supplies
- Compressed air supply system
- Nitrogen supply system
- Control systems (often a Distributed Control System (DCS))
- Emergency systems (often a System Integrated System (SIS))
- Fire and Gas system including:
    - Heat sensors
    - Flame sensors
    - Gas sensors
    - Cold sensors
- Fire water systems (not to be applied to an LNG spill as this would intensify vapor generation)
- Fire extinguishing systems
- Impoundment systems to contain LNG spills

- Security intrusion alarm systems
- Potable water systems
- Sewage water systems
- Flare or warmed gas vent system
- Many other site-specific systems, as dictated by the specific plant needs.

Closure

In this training, LNG technologies have been covered at a very high level and is not intended to be all inclusive training needed to be design, operate or maintain an LNG facility. This training is intended to present some introductory technical materials to help develop a culture of safety and reliability in your thought processes. It is intended to give the learner the basic technical knowledge needed as a starting point, to encourage further study, to make informed design, planning, maintenance and operating decisions.

In the follow-on lessons, more detail will be given on the operation of an LNG plant, refrigeration systems for liquefying, and the thermodynamics involved in producing, storing, transporting and re-vaporizing LNG.

A separate follow-on lesson will be produced on safety. This follow-on session will include topics such as safety interlocks, safety voting systems and management of change procedures.
Please remember that, **the most important intention of this document is to give you the basic technical knowledge, at an introductory level, that you need to start your study, on how to continue to make the Liquid Natural Gas Industry "Safe and Reliable".**