WHEN TRUST MATTERS

ALTERNATIVE FUELS FOR CONTAINERSHIPS

Contents

1 Introduction

1.0 About this document

This new series of reports gathers DNV's experience in the use of alternative fuels on containerships. In the first edition, we focus on the technical and commercial implications of LNG as a ship fuel in the sector.

1.1 Introduction

The pressure is on the maritime industry to decarbonize. The IMO strategy for reducing greenhouse gas (GHG) emissions has set a baseline, with incoming national regulations, in particular from the European Union, likely to result in further cuts. At the same time, public pressure to improve sustainability from consumers, charterers, financial institutions, and customers is building.

For shipping, the biggest lever to reduce emissions is to shift to low and zero-carbon fuels. With many new options emerging, however, the future fuel and technology picture for the industry is complex and becoming even more so. Picking the wrong fuel today could result in a significant competitive disadvantage tomorrow, due to customer preferences and the tightening regulations.

In the container sector, this is complicated because of the vessel greater fuel demand relative to other ship types, and their long trading distances. Today, the vast majority of the fleet runs on Heavy Fuel Oil/Low Sulphur Fuel Oil (HFO/LSFO), but significant recent newbuilding orders have been made with alternative fuels – primarily LNG.

This report examines the use of LNG in the container sector. LNG is a proven and available fuel solution, with an ever-increasing number of infrastructure projects planned along the main shipping lanes. We look at the regulations, engine and tank technology, bunkering infrastructure and operations, the commercial implications for new building and retrofits, and examine the case for LNG as a bridging fuel over HFO/LSFO and in transition to lower and zero-carbon options.

With this report and the series to follow, we will examine the most relevant new fuel options for the container sector. We hope to offer an overview of the most relevant factors to consider in shifting to alternative fuels, to help guide your decisions and turn uncertainty into confidence.

2 The Greenhouse Gas Challenge

The ambitions of the initial IMO GHG strategy are that by 2030, the average carbon intensity (a measure of carbon emissions per tonne-mile covered) of shipping should be 40% less than in 2008, and that by 2050, the carbon intensity should be reduced by 70% and total carbon emissions by 50%.

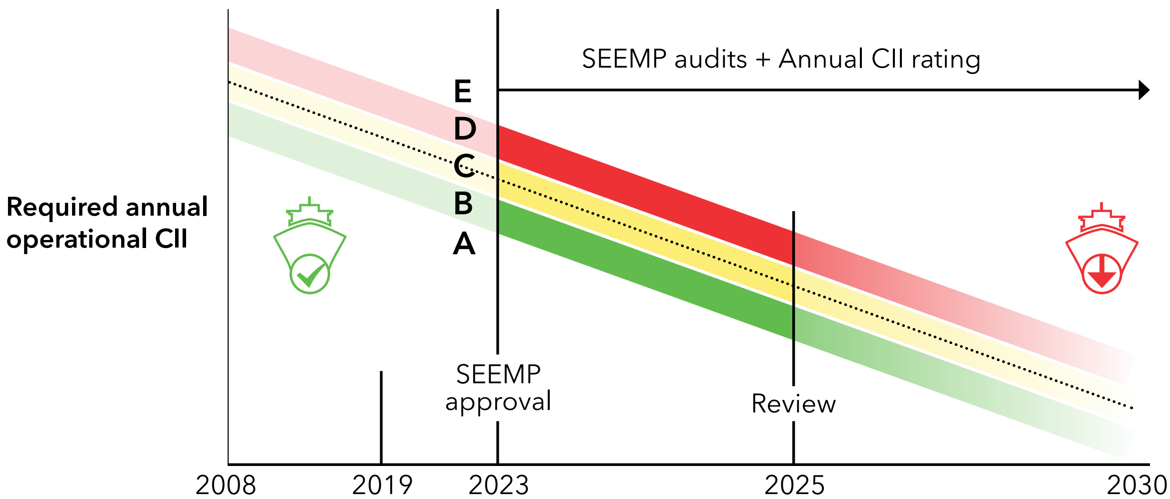
2.1 Initial IMO GHG strategy
The first short-term measures for achieving these targets were agreed at the IMO Marine Environment Protection Committee (MEPC 75) in November 2020, and include the following:

- The introduction of an Energy Efficiency Design Index (EEXI) for existing ships, which aims to bring older vessels up to a similar standard as newer tonnage. This is a one-time certification, due in 2023, and will impact most existing vessels. It is expected that most vessels will select engine power limitation (EPL) or introduce energy saving devices as a means for compliance.
- The introduction of the Carbon Intensity Indicator (CII) in combination with an enhanced Ship Energy Efficiency Management Plan (SEEMP), starting in 2023. The CII will be measured by the Annual Efficiency Ratio (AER), which is expressed as carbon dioxide (CO_2) emitted over the period of a year, divided by the deadweight tonnage (DWT) of a vessel and the miles covered over the same period. The CII will be assessed every year, and vessels that are above AER target levels will have to take action to reduce their emissions. These actions will have to be documented in the enhanced SEEMP. Discussions at MEPC 76 were inconclusive with regards to annual targets for the entire period until 2030, and a phased reduction approach was therefore adopted: starting with 2019 as the base year, a 1% reduction per year is required until 2022, followed by a 2% reduction per year until 2026. A review in 2025 will decide the reduction rate for the period 2027–2030.

The EEXI and CII measures are summarized in Figure 1 below.

FIGURE 1

Visual summary of the IMO measures Energy Efficiency Design Index and Carbon Intensity Indicator



A rating (A, B, C, D, E) will be given to each vessel annually as its CII = Carbon Intensity Indicator; A, B, C, D, E are the five EEXI = Energy Efficiency Design Index ratings to be given to a vessel; SEEMP = Ship Energy Efficiency Management Plan.

In addition to the above short-term measures, a number of proposals have been submitted to the IMO for medium- and long-term measures. These include, among others, a life cycle assessment of fuels, and the regulation of methane emissions from LNG engines.

While the EEXI will only affect the existing fleet, the CII will have an impact both on existing vessels and on those built in the future. A key question is what shipowners can do to ensure their vessels will be compliant for each ship's entire lifetime in view of the continuously stricter CII requirements.

There are three main ways of reducing carbon intensity:

- Introduction of energy-efficiency technologies/designs
- Alternative low-carbon fuels and optimization of operations
- Utilizing speed reduction on top

Currently, the main alternative fuel options available are LNG and liquefied petroleum gas (LPG), which can offer a reduction in carbon intensity of 15–25%. LNG technology is well-developed, and bunkering infrastructure is also developing fast. LPG is also emerging, with the first vessels already in operation and LPG infrastructure around the world already well-developed. Methanol gives a carbon-intensity reduction of approximately 10%. Using biofuels could offer a much more drastic reduction in the future, depending on what carbon factors the IMO adopts.

2.2 Upcoming EU regulations

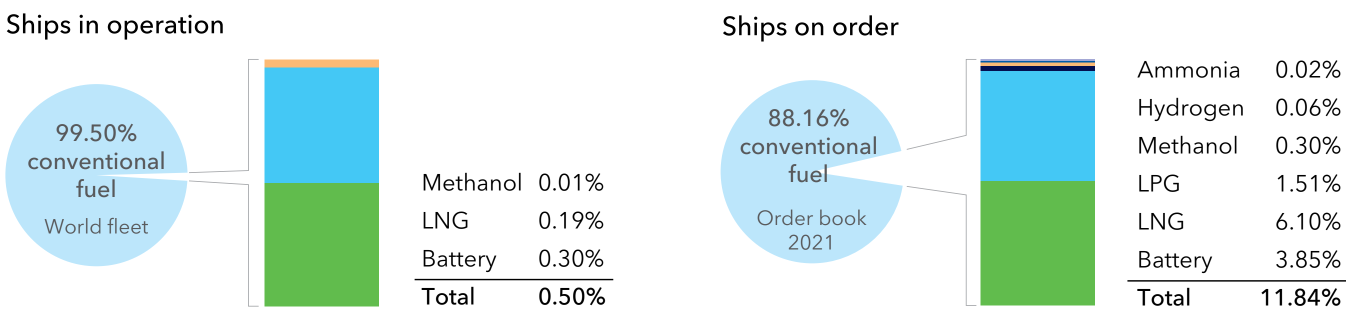
In July 2021, the European Commission unveiled its legislative proposal to enable the EU to attain its 2030 target of reducing its greenhouse gas emissions by at least 55% by 2030 compared with 1990 levels. The "Fit for 55" package includes 10 proposals, four of which are directly related to maritime:

- Inclusion of shipping in the European Emissions Trading Scheme (ETS) Directive
- Fuel EU Maritime Regulation: new policy measures to drive shift to low-carbon fuels, introducing requirements for gradually reducing the carbon intensity of marine fuels
- Revision of the Alternative Fuels Infrastructure Directive: shore-side electricity and LNG in core ports by 2030 (electricity) and 2025 (LNG)
- Revision of the Energy Taxation Directive: ending tax exemptions for marine fuels

Figure 2, based on the current world fleet and known order book, shows that the uptake of alternative fuels in the world fleet is limited but increasing fast. Less than 1% of the existing fleet runs on alternative fuels. Much of that fleet are smaller vessels in short-sea shipping. But close to 12% of newbuildings are ordered with alternative fuels, mostly LNG, and some of these are larger vessels for deep-sea shipping. It is interesting to see a big change happening. For the newbuildings ordered in 2020 alone, more than a fifth (22%) are planned with alternative fuels;

FIGURE 2

Alternative fuel uptake



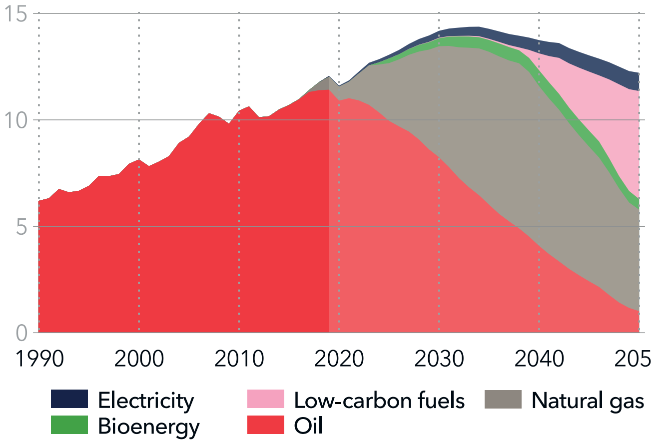
Key: LNG = liquefied natural gas; LPG = liquefied petroleum gas
Sources: IHSMarkit (ihsmarkit.com) and DNV's Alternative Fuels Insights for the shipping industry – AFI platform (afi.dnv.com)

mostly LNG (16% of the total), but also LPG (5%) and methanol (1%). In the first four months of 2021, 18% of all newbuilding orders selected LNG as fuel, while all LPG carriers ordered so far in 2021 have selected LPG. Most of

FIGURE 3

World maritime subsector energy demand by carrier

Units: EJ/yr



Natural gas includes LNG and LPG. Biomass includes advanced biodiesel and LBG.
Historical data source: IEA WEB (2020)

the LNG-fuelled vessels are large ones, and it is therefore expected that their share in terms of gross tonnage (GT) will be even higher.

The key challenge for the maritime sector is that it cannot easily electrify propulsion. We therefore expect that the IMO's 2050 target (at least 50% reduction in emissions in absolute terms by 2050 from a 2008 baseline) will be met through a combination of:

- Slow-steaming
- Better asset use
- Efficiency improvements
- A massive fuel shift to low- and zero-carbon fuels such as
  - LNG, LPG, methanol,
  - hydrogen, ammonia, and other electrofuels,
  - biofuel
  - electricity for short-sea shipping and port stays

Low-carbon fuel, including biofuels, electrofuels, and clean ammonia, will start being introduced in larger volumes in around 2030, and their uptake should increase significantly towards 2050 in order to achieve the IMO's ambitions. Figure 3 illustrates a possible scenario of the energy demand development for shipping, showing the important role of LNG, while all low-carbon energy carriers (biofuel/electrofuel, ammonia, hydrogen) are included in the low-carbon category.

Is LNG a good transition fuel or should we wait for the perfect zero-carbon fuel?

When considering alternative fuels in general, a number of parameters have to be considered, such as availability, infrastructure, maturity of technology, energy density, cost, and the environmental performance of the fuel. As shown in Figure 4 below, only fuel oil – represented by Very Low Sulphur Fuel Oil (VLSFO) or Marine Gas Oil (MGO) – fits most criteria, except for environmental performance. When considering low-carbon fuels, there is still much development needed, mainly in terms of availability and maturity of technology. Due to uncertainty related to these developments, using LNG and LPG today offers a possibility to reduce GHG emissions by 15–20%, while at the same time preparing for other low-carbon options. An LNG-fuelled vessel can start using bio-LNG to reduce its carbon footprint, while there is the possibility to design it to be ammonia-ready. An LPG-fuelled vessel is even more suitable for later conversion to ammonia.

Figure 5 illustrates how pressure from regulators and key commercial stakeholders like financiers and charterers will push shipowners to ensure that their ships stick to an acceptable GHG emission trajectory (such as the IMO Carbon Intensity Indicator (CII) requirements). Above this trajectory, the shipowner is exposed to regulatory and commercial risk; so, for a new ship to retain its asset value throughout the next decades, taking GHG target trajectories into account in design will be critical. Figure 5 also illustrates how a shipowner will need to identify a "decarbonization stairway" to remain below the required GHG emission trajectory. This stairway illustrates the chosen risk-mitigation strategy and how the introduction of new fuels and technologies at various points in time

FIGURE 4

Alternative fuel parameters to be considered

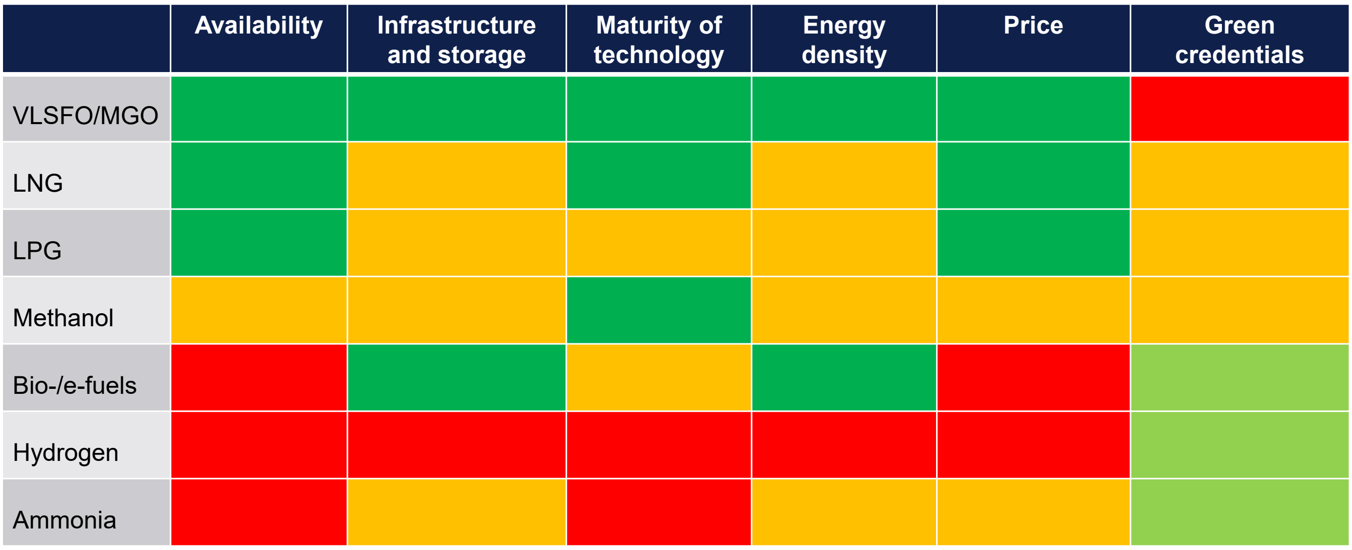
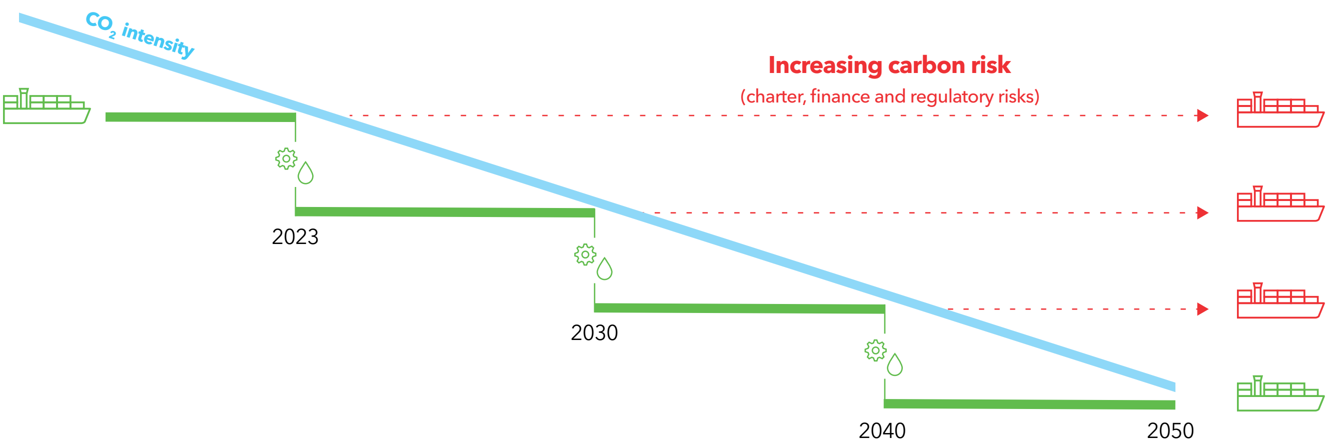


FIGURE 5

The decarbonization stairway and potential exposure to carbon risk



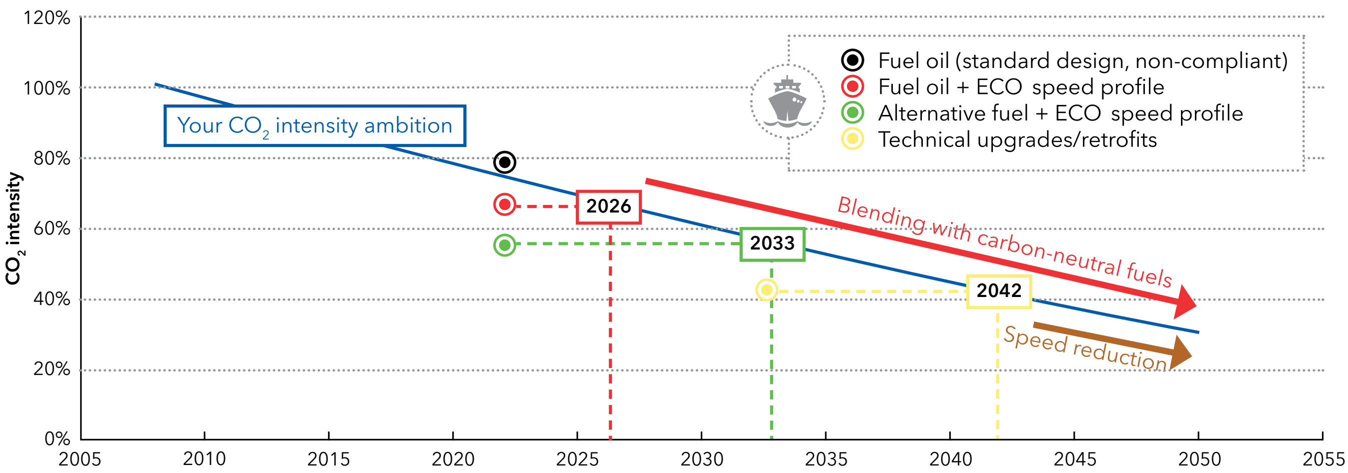
enables the emission intensity for the ship to stay below the required level. Naturally, understanding the costs associated with the stairway is vital – as is the understanding of the technical design implications of the chosen strategy. In the shorter term, energy-efficiency measures and energy harvesting combined with operational measures may be sufficient; but in the longer term, the use of alternative fuels will be necessary to meet the GHG trajectory. This also means that the ship should be designed to allow for the needed upgrades or fuel changes later in its lifetime. Thus, it is an important intervention point when a vessel is being commissioned, to influence its emissions through its lifetime in a cost-effective manner.

The use of methanol can also be an option for today's newbuild vessels, though the environmental benefits of using fossil methanol are rather limited, and the fuel price is also relatively high. Due to its ease of handling, methanol can be an attractive alternative once low-carbon methanol (bio-methanol or e-methanol) are available.

Using LNG or LPG today can have a positive impact on a vessel's CII, therefore allowing a newbuilding design to be comfortably below IMO targets for at least the first decade of its lifetime. This is illustrated in Figure 6 below showing the CII for an example vessel. A conventional design may find itself above the IMO reference line (CO_2 ambition in the graph) already by 2022 (black dot). Introducing LNG as fuel (green dot) can shift the carbon intensity down significantly, allowing the vessel to be compliant until 2033 in this example, without other measures being taken. Beyond 2033, other measures will have to be taken, such as speed reduction, the introduction of more advanced energy-saving systems, and use of low-carbon fuels.

FIGURE 6

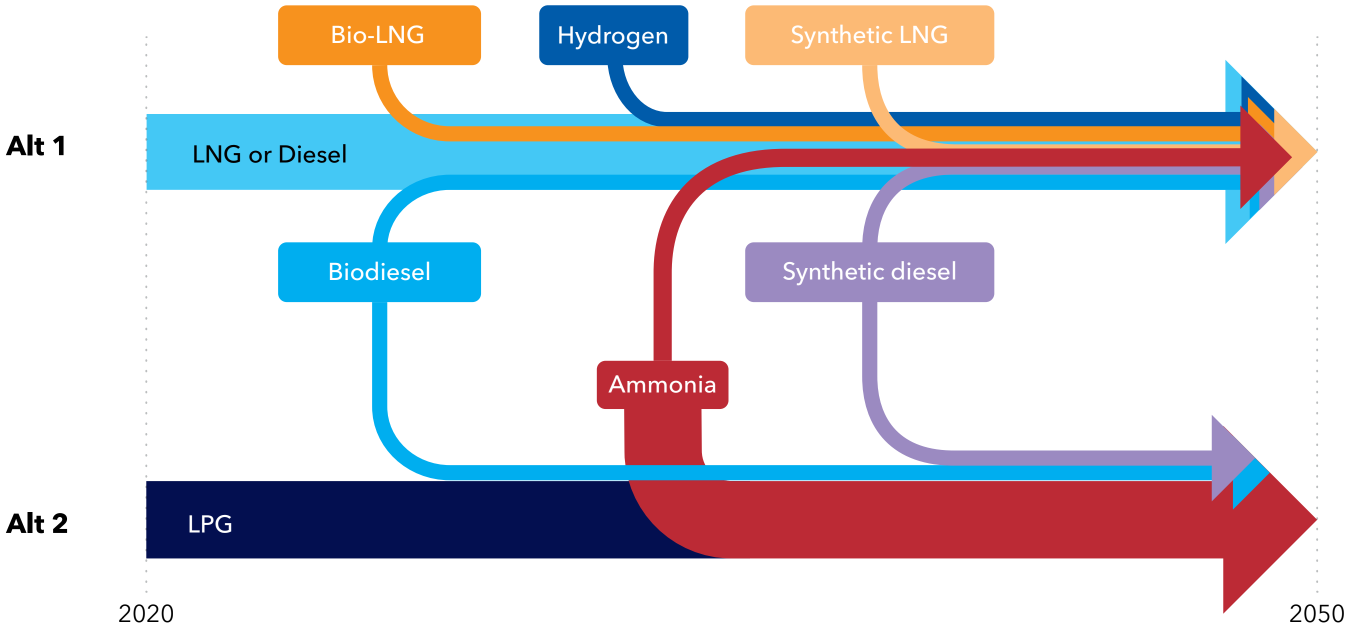
Gradual increase in CO_2 reduction requirements



*Key CO_2 = Carbon dioxide; E: Energy consumption optimization

FIGURE 7

Fuel option outlook until 2050

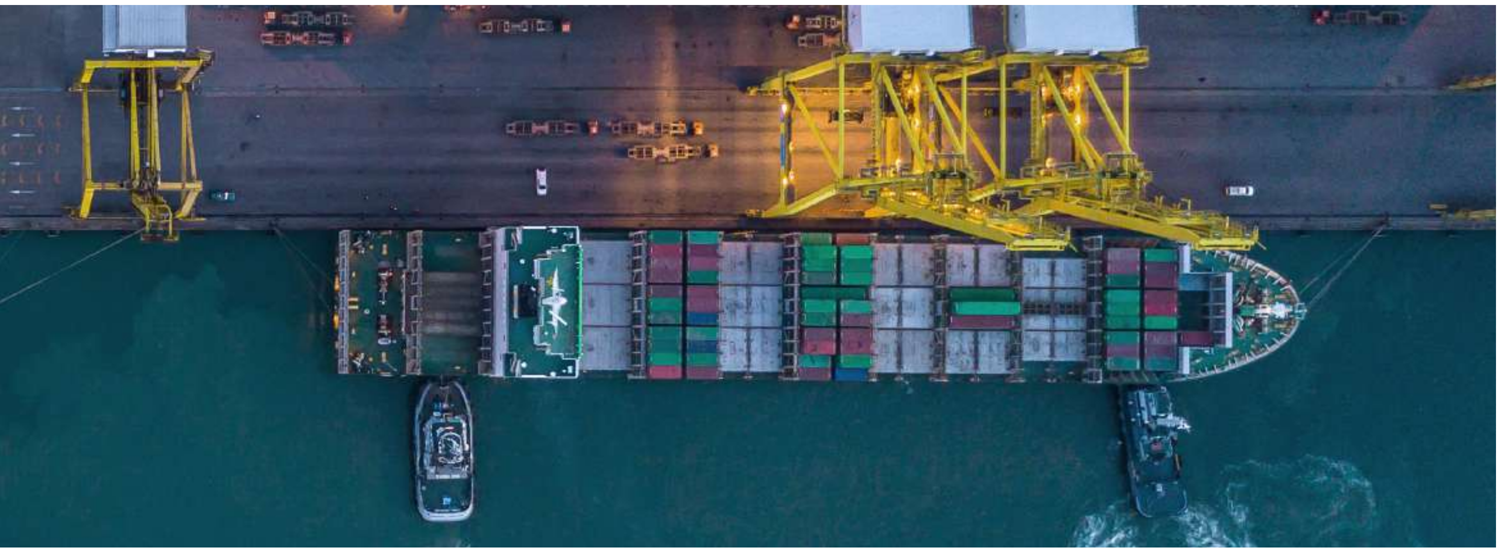


Fuel flexibility and bridging technologies can facilitate the transition from traditional fuels, via fuels with lower-carbon footprints, to carbon-neutral fuels, and can require limited investments and modifications along the way. In the transition phase, investing in fuel flexibility and bridging technologies is a good way to prepare for a low-carbon future.

As indicated in Figure 7, we could start with conventional fossil fuel and later shift to carbon-free or carbon-neutral fuel alternatives. In deep-sea segments, dual-fuel combustion engines and alternative fuel-ready solutions could help reduce future retrofit costs.

In addition, the transition from traditional to carbon-neutral fuels can be eased through bridging technologies such as:

- Fuel-flexible energy converters
- Fuel-flexible storage tanks or onboard systems
- Flexible shore-side fuel infrastructure



3 Liquefied Natural Gas (LNG)

This chapter provides a basic overview of the technical components for LNG storage and handling of gas fuel on board, the design of machinery spaces, the available combustion engine types, and aspects of maintaining the condition of fuel storage. Technical and commercial aspects will also be discussed, including ship bunkering.

3.1 General

LNG offers the opportunity to reduce greenhouse gas (GHG), NOx and Particulate Matter (PM) emissions. NOx emissions can be reduced by 20–80%, depending on engine technology, while Exhaust Gas Recirculation (EGR) or Selective Catalytic Reactor (SCR) systems ensure that IMO NOx Tier III levels can be achieved. PM emissions are also drastically reduced, but these are currently not regulated. When it comes to GHGs, both CO_2 and CH_4 (methane) emissions are to be considered, the latter being emitted as a result of incomplete combustion (methane slip). Methane leaks throughout the entire fuel value chain – including fuel production, transportation and distribution – which contributes to the overall GHG footprint. But this is currently not included in IMO regulations. The following paragraphs provide further details and considerations of these issues.

100-year vs. 20-year Global Warming Potential

When accounting for methane emissions from LNG engines, two different Global Warming Potential (GWP) factors are often used:

a) 100-year GWP (GWP100), which is the standard measure. According to this, methane is a 28 times more potent greenhouse gas than CO_2.
b) 20-year GWP (GWP20), according to which methane is 84 times more potent than CO_2 as a GHG.

In other words, methane has a much stronger warming effect in the short term, but it quickly breaks down, having an estimated mean half-life of 9.1 years. In this context, there is discussion over whether GWP100 or GWP20 should be used to reflect the efficiency of reducing GHG emissions.

The GWP was introduced by the Intergovernmental Panel on Climate Change (IPCC), which also uses the measure to illustrate the difficulties in comparing components with differing physical properties using a single metric. The GWP100 was adopted by the UN Framework Convention on Climate Change (UNFCCC) and its Kyoto Protocol, and is now used widely as the default metric. The reason for this is that climate change is a long-term problem, and we should look at the solutions with the best overall impact in the long term. DNV follows the UNFCCC approach and only uses the GWP100 factor of 28 (see "a)") when accounting for methane emissions.

3.2 Direct comparison between LNG and HFO

Key differences between LNG and HFO are as follows:

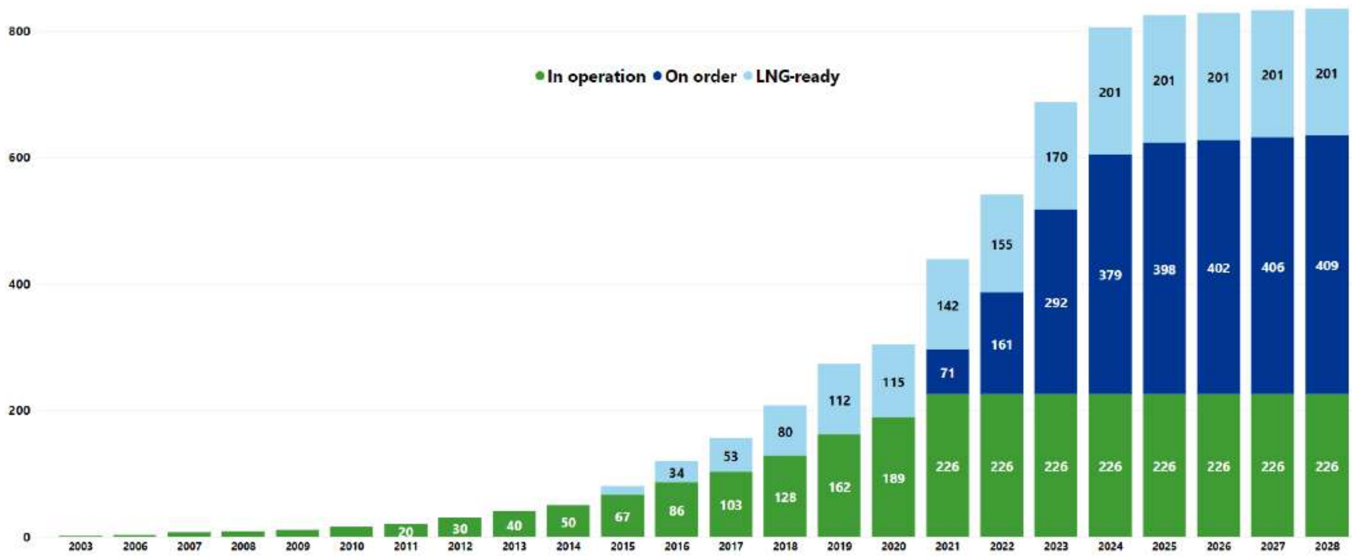
- LNG is a GHG with methane (CH_4) as its main component.
- The volume of LNG is 600 times less than that of natural gas. The liquid phase depends on the temperature (deep cooled -162°C) and/or the pressure (e.g. Type C tank: 6–10 bar). Handling LNG is thus more complex.
- Emissions reduction depends on engine type and is in the order of:
  - 95–98% for SOx
  - 20–80% for NOx
  - 14–25% for CO_2
- International regulations for all related matters are available.
- The use of LNG influences EEDI/EEXI and CII directly.
- There are bunkering facilities around the world (see Figure 11), and more infrastructure is under development.
- The volumetric energy density of LNG is approximately 43% of that for HFO. But LNG's energy density per mass is approximately 18% higher than that of HFO.
- Due to the smaller volumetric energy density, the tank volume has to be greater for an LNG-driven vessel (theoretically by a factor of two, but up to three due to isolation, tank geometry, etc.).
- Technology is available. The main engines and generators run on LNG and/or HFO.
- The technology is available for the green production of LNG from CO_2 and green hydrogen (made by electrolysis powered by renewable sources such as solar). Large-scale production of green LNG can be expected in the near future.

3.3 Ship fleet and development

As of September 2021, there are 221 LNG-fuelled ships in operation (excluding LNG tankers) and confirmed orders for another 359, all newbuildings. In recent years, a shift in LNG utilization from short-sea shipping to large, ocean-going vessels has been taking place. This trend is expected to continue, leading to higher penetration of LNG in the marine fuel market in the current decade.

FIGURE 8

Development of LNG-fuelled fleet



3.3.1 LNG demand and forecast

Figure 9 shows the LNG consumption for existing ships and those on order. Demand for LNG as fuel is expected to increase exponentially in the next few years, principally because large LNG-fuelled vessels have been, and are still being, ordered.

Figure 10 shows the availability of various alternative fuels. The red line represents the total HFO/LSFO demand of the maritime industry, and the bars illustrate the total production of each fuel. It can be seen that the amount of LNG is much higher than for other alternative fuels. Bunkering infrastructure for LNG is also being developed rapidly. Most major shipping hubs are already covered to a certain extent, and more projects are planned for the near future to ensure LNG availability for shipping, as discussed in the next section.

FIGURE 9

LNG consumption for confirmed fleet

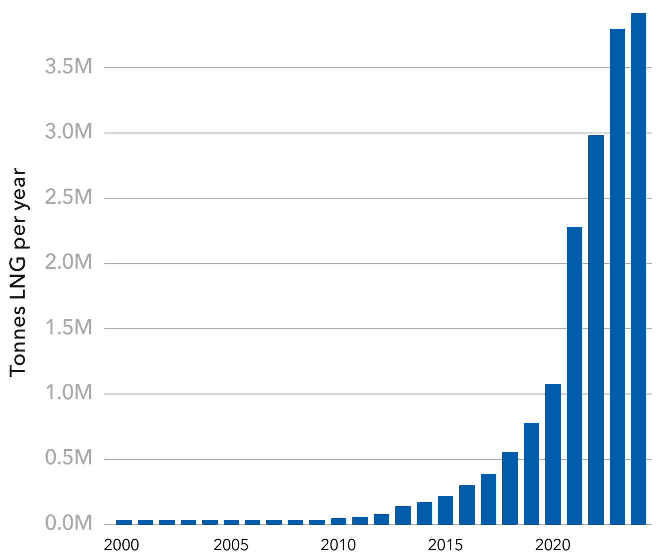


FIGURE 10

Availability of alternative fuels

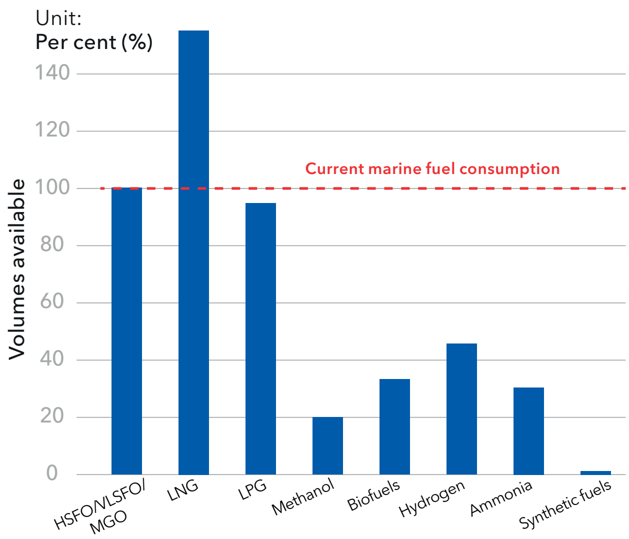


FIGURE 11

Bunkering infrastructure around the world

3.3.2 Infrastructure and development

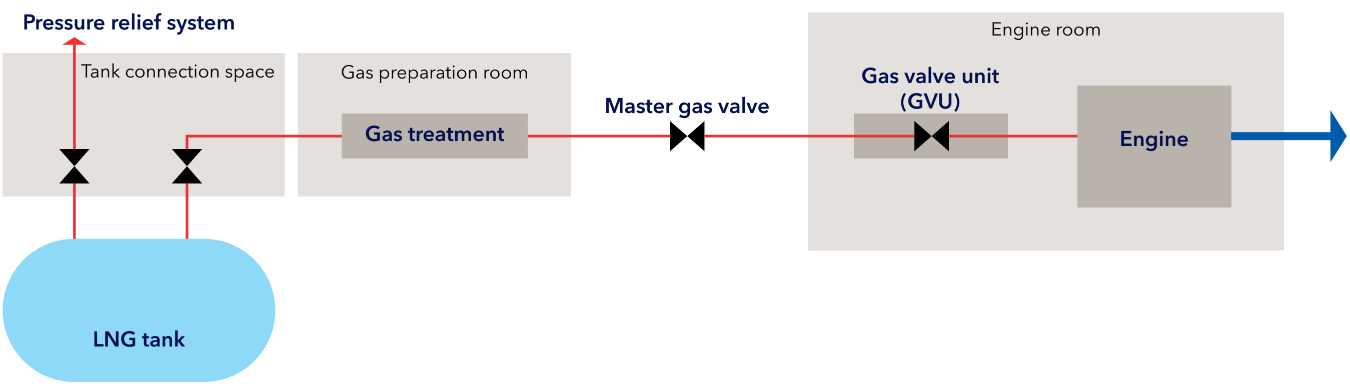
LNG bunkering infrastructure to serve the growing fleet of ships using the fuel is still under development. Figure 11, from DNV's Alternative Fuel Insights platform, shows the present status of such infrastructure globally.

Most bunkering facilities today are in Europe. Norway, in particular, has many bunker hubs in operation, because using LNG as ship fuel originated there. LNG fuel is available along the main shipping routes and in the most important and biggest ports for bunkering. As the fleet of LNG-fuelled vessels develops dynamically, more LNG bunkering facilities are being discussed and will come into service in the coming years.

3.4 Ship fuel technology

FIGURE 12

Graphical illustration of gas handling on board of a containership



3.4.1 Fuel systems and engines

Because LNG is bunkered and stored on board as a deep-cooled liquid, but burned in the engine as a gas, different considerations come into play compared with traditional fuel oil propulsion plants. The low flashpoint (below 60°C) of natural gas gives rise to several safety-related aspects and requirements.

The specific requirements are laid down in the IMO's International Code of Safety for Ships using Gases or other Low-flashpoint Fuels (IGF Code). The IGF Code addresses standards for ships using low-flashpoint fuel in general, but the current version focuses on regulations to meet the functional requirements for gas fuel (LNG). The respective functional requirements are defined in Section 3 of the IGF Code. From these may be derived the basic safety principles that apply to the gas installation's several parts and components, as summarized in Figure 13.

In the following subsections, reference is made to these safety principles, as applicable, for each respective component of the system.

FIGURE 13

Safety principles

Segregation Protect gas fuel installation from external events	**Double barriers** Protect the ship against leakages
Segregation Give warning and enable automatic safety actions	**Emergency shutdown** Reduce consequences of a leakage

3.4.2 LNG containment systems / tanks

LNG's lower energy density than HFO (see 3.2) means significantly more space is required to carry the necessary fuel volume compared with HFO. This additional volume reduces the available cargo space. The following tank types have been developed and are in use for cryogenic liquid gas transport, and may also be used for gas as fuel:

- Type A
- Type B
- Type C
- Membrane

Those currently in use for LNG fuel are Type B prismatic tanks, Type C tanks and membrane tanks. But the design of such tanks needs to be adjusted in comparison with the cargo tank design to comply with the IGF Code and to take different filling levels into consideration.

The pros and cons are discussed in the following subsections.

New hybrid designs approaching the market – for instance Lattice tank, Bi-Nut tank – aim to combine the advantages of Type B and Type C tanks, such as:

- The good space utilization of prismatic tanks
- The safety concept and higher design pressure of Type C tanks

It is necessary to pay special attention to considering the variable filling levels for gas fuel tanks. The filling level of fuel tanks reduces during the voyage, from the maximum (95%) to minimum level (10%). These intermediate levels have a large impact on the different tank loads. Particularly sloshing loads very much depend on the actual filling and need to be taken into consideration for the tank design.

3.4.2.1 Safety principles for tanks

Three different safety principles are used in different combinations for tank containment systems:

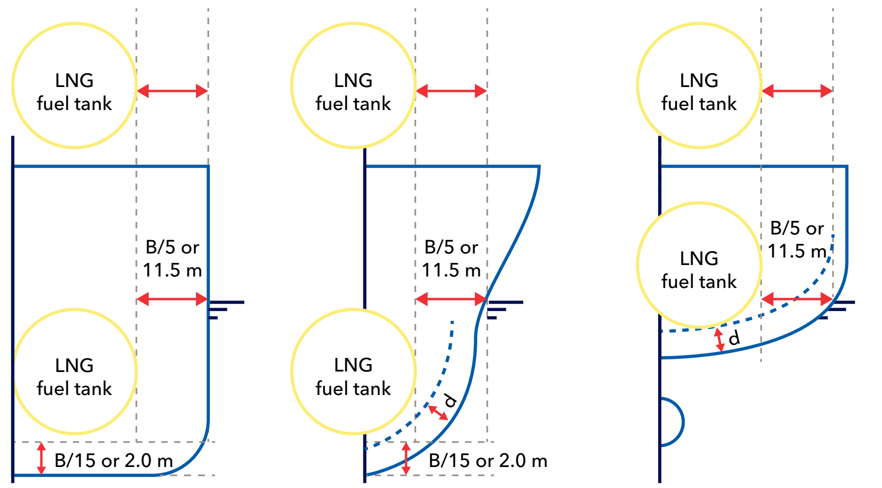
a) Segregation
The fuel tanks shall be separated from exposure to collision, grounding, and other mechanical damage scenarios, such as cargo operations. In addition, they shall be located away from areas of fire and explosion risks.

b) Double barriers and thermal insulation system
Many tank types maintain a high safety level over time by using the double barrier concept, whereby the tank itself containing high pressures and/or cryogenic liquid gas is the first barrier. A full or partial second barrier is used to protect the crew, ship and environment from gas spill and cryogenic effects (e.g. brittle material). Only the Type C tank follows another safety principle: its design has such a high safety margin for fatigue and crack initiation that a second barrier for the tank itself is not necessary.

c) Leakage detection
All tanks below deck shall be monitored for leakages, allowing a targeted response by the master and crew. A leakage can only be repaired when the gas tank is empty and heated. The IGF Code allows a maximum operation time of 15 days with a leaking tank.

TABLE 1

Comparison of requirements for minimum tank distances to the shell plating

Deterministic approach	Probabilistic approach
Minimum distance from side: B/5 or 11.5 m (whichever is less) Minimum distance from bottom: B/15 or 2.0 m (whichever is less) At no point closer to the shell plate than "d" d = 0.8–2.0 m for cargo ships, depending on tank size	Probability of tank damage for cargo ships $f_{CN} < 0.04$ $f_{CN} = f_l \times f_t \times f_v$ f_l = probability for the collision damage in the longitudinal direction f_t = probability for inboard penetration accounting for available side protection f_v = probability accounting for vertical extent of damage
	Formulations are based on and refer to SOLAS Regulations II-1/7-1 and 7-2.6, used for damage stability calculations of cargo and passenger ship.
	The factor f_l is calculated by use of the formulations of the p-factor in SOLAS Regulation II-1/7-1.
	The factor f_t is a function of the distance between tank and side shell.
	The factor f_v is a function of the distance from the deepest draught and to the lowermost extreme boundary of the LNG tank.

3.4.2.2 Segregation – Deterministic and probabilistic requirements for tank locations

The geometrical segregation of gas fuel tanks from the shell and bottom plating, and from the collision bulkhead, is driven mainly by the requirements of the IGF Code (Pt.A-1, 5.3).

The requirements are either deterministic or based on a probabilistic approach. While the deterministic approach defines minimum distances of the tank, the probabilistic method considers the probability of damages and may allow smaller distances of the tank to surrounding structure, giving a higher design flexibility. The probabilistic approach follows the principles of the SOLAS convention's probabilistic damage stability calculation.

TABLE 2

Tank type overview

Feature	Independent tanks			Integral tank
	IMO Type A	**IMO Type B**	**IMO Type C**	**Membrane**
Geometry	Self-supporting independent prismatic tank with option of inclined boundaries		Pressure vessel (cylindrical, bi-lobe, tri-lobe design)	Prismatic tank, built into the supporting ship structure
Space utilization	Good		Low to Moderate	Moderate to Good
Temperature / pressure	–163°C / < 0.7 bar		NA / > 2.0 bar (overpressure possible)	–163°C / < 0.7 bar
Barriers	2 barriers Second barrier enclosing the tank, able to contain liquid gas for 15 days	2 barriers Partial second barrier, designed to contain liquid phase of LNG fuel for 15 days	1 barrier	2 barriers Second barrier enclosing the tank
Design complexity	Moderate	High	Low to Moderate	Moderate
Manufacturing	Pre-fabrication – independent of ship structure		Pre-fabrication – independent of ship structure; may be located on deck	Construction of the tank inside the pre-manufactured tank compartment
Material	9% nickel steel, stainless steel, aluminium	9% nickel steel: high-manganese steel	9% nickel steel	Stainless steel
Sloshing risk	Small due to swash bulkhead		Small due to shape, volume, and swash bulkheads	High
Main challenges	Second barrier	Design complexity	Weight and space utilization	Sloshing and serial construction

3.4.2.3 LNG tank types – an overview

The IMO has defined three basic, independent LNG tank types: IMO Type A, IMO Type B and IMO Type C. The two basic physical principles that can keep the natural gas in its liquid phase are:

- High pressure
- Low pressure with deep temperature

In addition, fully integrated membrane tanks – the same concept as used on large LNG carriers – are commonly employed as fuel gas storage systems.

Tank breadth is a general challenge for gas fuel tanks of large containerships because it allows free motion of the fluid due to ship rolling. Tanks without sloshing bulkheads may be subject to extensive sloshing impact loads. A reduction of such loads can be achieved with an optimized tank geometry (increasing the slope of tank walls connecting the tank bottom with side walls), though this has a negative impact on the space utilization.

3.4.2.4 Type A tank

The Type A tank has a design pressure of 0.7 bar that allows a prismatic shape for the containment system, which is able to utilize the existing space.

Typically, a longitudinal non-tight bulkhead acts as a swash bulkhead and eliminates the risk of excessive sloshing impacts.

The safety philosophy of a Type A tank considers the possibility of severe structural failure that would imply the loss of tank integrity. Therefore, the tank has to be provided with a complete secondary liquid-tight barrier. This barrier is mounted on the structure of the vessel and is capable of safely containing all potential leakages through the primary barrier and, in conjunction with the thermal insulation system, of preventing the lowering of the temperature of the ship structure to an unsafe level. Typical materials are stainless steel, 9% nickel steel (Ni-steel) or aluminium.

Important design aspects

The strength requirements for the ship and tank structures from the IGF Code and the classification society shall be proven by finite element analyses of the partial ship hull, including the tank and its supporting structure, consisting of ultimate and fatigue assessments.

Special attention shall be given to the tank supports to prevent floating in case of a damaged hull with water ingress and rolling (non-linear behaviour).

The boil-off gas calculation is a main design criterion for the tank. The shape of the tank, the thickness and material selection of the insulation have a significant impact on the boil-off gas rate.

Advantages

- Independent LNG fuel tank, designed based on conventional ship structure design principles
- Less design effort in comparison to Type B and membrane tanks
- Prismatic shape with high volume/space efficiency, including optional sloped geometry
- Pre-fabrication and flexible supply
- Can be equipped with swash bulkheads to limit sloshing

Disadvantages

- Limited design and construction experience in the maritime industry
- Construction time: second barrier, including additional insulation, needs to be built into the tank compartment
- Potential limitations in suppliers
- Requires additional boil-off gas management solution due to pressure limitation
- Stainless steel requires supports of same material
- Insulation of tank supports
- Limited repair possibilities for the insulated tank compartment boundaries

Further information, requirements and regulations for this tank type can be found in Table 3 below.

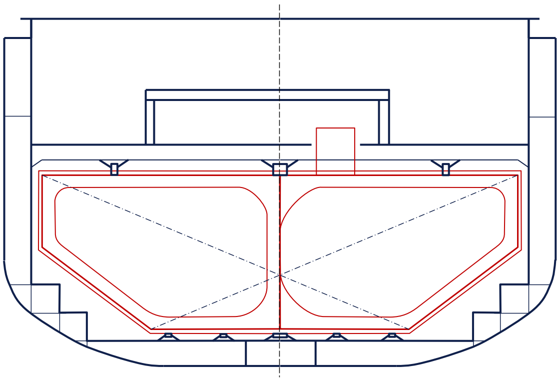
TABLE 3

Rule reference for Type A and B tanks

DNV Class Guideline: CG-0554	Gas-fuelled containership with independent prismatic tanks Type A and Type B
DNV Class Guideline: CG-0133	Liquefied gas carriers with independent prismatic tanks of Type A and B
DNV Class Rules: DNVGL-RU-SHIP Pt.5 Ch.7 Sec.4	Liquefied gas tanker – Cargo containment
DNV Class Rules: DNVGL-RU-SHIP Pt.5 Ch.7 Sec.20	Liquefied gas tanker – Design with independent prismatic tanks of Type A and B
DNV Class Rules: DNVGL-RU-SHIP Pt.5 Ch.2 Sec.4	Containerships – Gas fuel tank finite element analysis
DNV Class Rules: DNVGL-RU-SHIP Pt.6 Ch.2 Sec.5	Gas-fuelled ship installations – Gas-fuelled LNG
DNV Class Guideline: CG-0127	Finite element analysis
DNV Class Guideline: CG-0129	Fatigue assessments

FIGURE 14

Type B tank



3.4.2.5 Type B tank

The Type B tank has the same design pressure of 0.7 bar as a Type A tank. This allows a prismatic shape for the containment system, which is able to utilize the existing space. Longitudinal bulkheads eliminate the risk of sloshing events and tank damage.

The safety philosophy of a Type B tank has its focus on the integrity of the primary barrier and control over possible crack propagation. The leak-before-failure approach requires extensive ultimate and fatigue assessments by means of finite element analysis (FEA), including crack propagation and leakage rate analysis, to reduce the probability of leakage. Detailed knowledge about small allowable leakage rates for all critical tank areas allows a partial secondary barrier consisting of drainage channels in the insulation and drip trays which are able to contain the liquid phase of LNG fuel for 15 days (see IGF Code Pt.A-1 6.4.5: Small leak protection system) The design requirements consider a higher safety margin than for a Type A tank.

Type B tanks are typically made of 9% nickel steel. High-manganese steel may only be used with agreement of the flag administration.

Important design aspects

In addition to the design aspects for a Type A tank, all critical tank locations have to be assessed with regard to crack propagation based on the fatigue assessments. Fifty or more critical locations for a 15,000 m³ tank may be assessed.

Drainage channels need to be included in the insulation to guide possible leaked liquid gas to the drip trays (small open tanks below the fuel tank, allowing a controlled vaporization of the leaked cryogenic liquid gas).

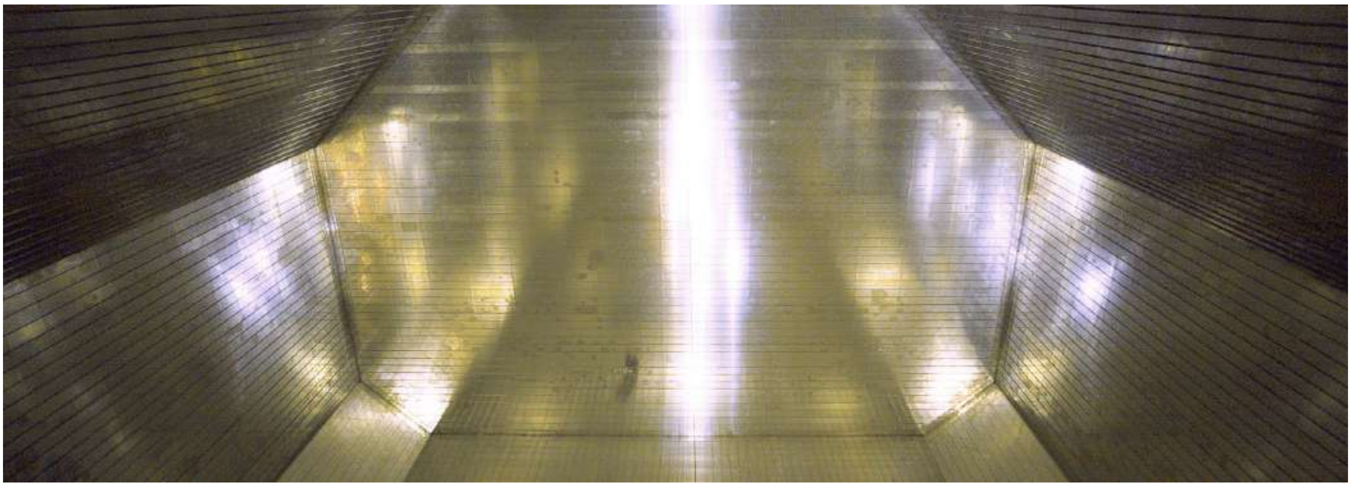
Advantages

- Independent LNG fuel tank, designed based on conventional ship structure design principles
- Prismatic shape with high volume/space efficiency, including optional sloped geometry
- Partial secondary barrier consisting only of drainage and some drip trays
- Can be equipped with swash bulkheads to limit sloshing
- Some designers and yards with LNG cargo design and service experience
- Pre-fabrication and flexible supply

Disadvantages

- Extensive design calculation efforts – Ultimate Limit State (ULS), Fatigue Limit State (FLS), crack propagation, leakage
- Requires additional boil-off gas management solution due to pressure limitation

Further information, requirements and regulations for this tank type can be found in Table 3.



3.4.2.6 Type C tank

A Type C tank has a design pressure greater than or equal to 2 bar and is designed for gas as fuel applications up to 10 bar.

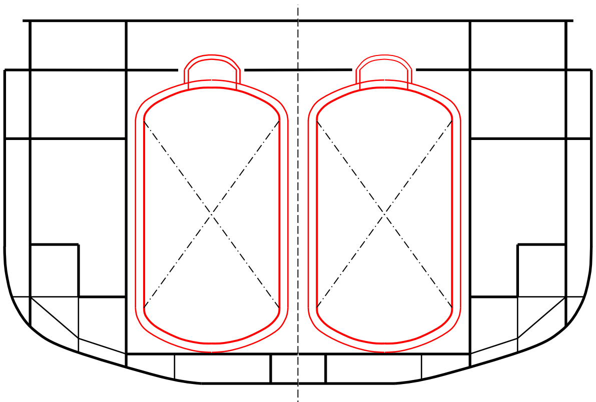
Due to the design pressure, this containment system requires a cylindrical shape. Bi-lobe tanks or tri-lobe tanks are state-of-the-art. Single Type C tanks and bi-lobe tanks are currently the preferred solution for Type C tanks. The utilization of available tank compartment space is reduced in comparison with Type A and Type B tanks. Smaller units may be located on deck.

The safety philosophy of a Type C tank assumes that it is almost impossible that cracks in the tank shell will create a leakage within the ship's lifetime. A very conservative strength approach based on the minimum design vapour pressure (IGF Code) allows neglect of the secondary barrier.

Sloshing is not an issue for cylindrical tanks, nor for wider bi-lobe or tri-lobe tanks which are built with swash bulkheads.

FIGURE 15

Type C tank



Vacuum insulated cylindrical tanks are a special design used for sizes up to 1,000 m³.

Important design aspects

Bi-lobe tanks are made of two cylindrical tanks sharing the same centreline bulkhead. The ring frames formed with this bulkhead structure are called Y-joints.

These joints are critical areas for this tank type. Special attention is needed in view of material selection, welding and fatigue aspects.

Smaller cylindrical tanks are often mounted on deck, where green sea loads shall be considered for the foundation of the tank.

Advantages

- Designed and built to pressure vessel standards
- Independent LNG fuel tank, supported by ring frames
- No secondary barrier needed
- Can be equipped with swash bulkheads to limit sloshing
- Simple boil-off gas management and high operational flexibility (extended holding time)
- Extensive service experience as fuel tanks and cargo tanks (cylinders)
- Pre-fabrication and flexible supply
- Installation on or under deck in all directions possible (longitudinal, transverse, vertical)
- Easy to apply for yards that have less experience with LNG carriers or LNG as fuel

Disadvantages

- Only moderate volume/space efficiency
- Very high safety factors lead to heavy weight in comparison to other tank types
- Bunker ship bunker pressure to be in accordance with fuel tank pressure

Further information, requirements and regulations for this tank type can be found in Table4 below.

TABLE 4

Rule reference for Type C tanks

DNV Class Rules: DNVGL-RU-SHIP Pt.6 Ch.2 Sec.5	Gas-fuelled ship installations – Gas-fuelled LNG
DNV Class Rules: DNVGL-RU-SHIP Pt.5 Ch.7 Sec.4	Liquefied gas tanker – Cargo containment
DNV Class Rules: DNVGL-RU-SHIP Pt.5 Ch.7 Sec.22	Liquefied gas tanker – Design withType C cylindrical tanks
DNV Class Guideline: CG-0135	Liquefied gas carriers with independent Type C cylindrical tanks
DNV Class Guideline: CG-0127	Finite element analysis
DNV Class Guideline: CG-0129	Fatigue assessments

3.4.2.7 Membrane tank

A membrane gas fuel tank has a design pressure of 0.7 bar. The tank boundary consists of multiple layers of insulation and two barriers, and is glued into the pre-constructed tank compartment. The ship structure carries the combination of hull girder loads, sea loads and tank loads. The primary barrier is a thin layer of multiple stainless steel panels (t <= 1.0 mm) which may feature corrugations to allow thermal expansion.

The prismatic shape generally allows good utilization of the existing space. Membrane tanks are not well suited for a more complex geometry with inclined walls outside of the parallel midship area.

The safety philosophy of a membrane tank has its focus on early leak detection and the existence of a complete secondary barrier.

Important design aspects

Due to the absence of any inner structure, the LNG can freely move inside the tank. Depending on the actual filling, loading condition and dynamic motions, severe sloshing impact loads may be generated. Without the option to install a swash bulkhead in a wide tank, only large lower sloped walls or significant ly smaller tanks can be used to reduce the risk of severe sloshing impact loads. This has a negative impact on the space utilization.

Advantages

- High volume/space efficiency without large sloped lower walls
- Low self-weight
- Extensive service experience as cargo tanks
- Allows rapid cool-down

Disadvantages

- Limited application as fuel containment
- Only serial construction after ship tank compartment is completely finished (cost and delivery)
- Potential limitations in suppliers
- Requires additional boil-off gas management solution due to pressure limitation
- Potential limitations in positioning of tank
- Requires crew competence on gas detection and leak monitoring systems (depending on automation systems)
- Limited repair possibilities for hold space boundaries

Further information, requirements and regulations for this tank type can be found in Table 5 below.

FIGURE 16

Membrane tank

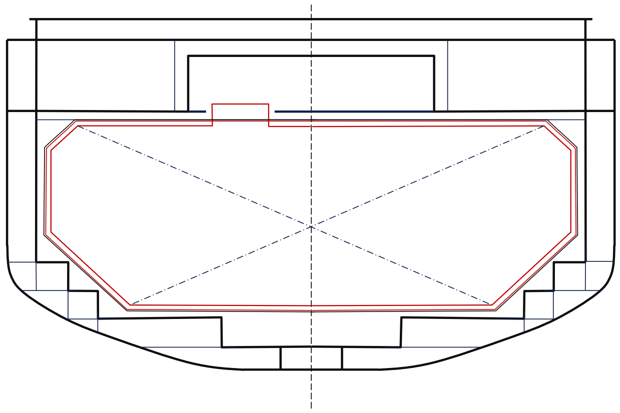


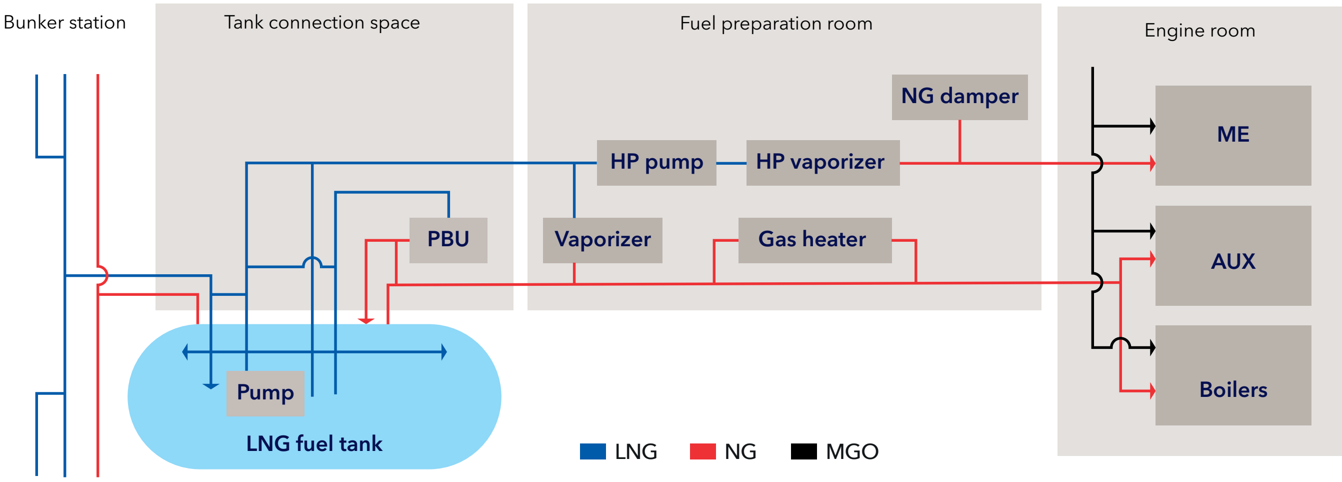
TABLE 5

Rule reference for membrane tanks

DNV Class Rules: DNVGL-RU-SHIP Pt.5 Ch.7 Sec.4	Liquefied gas tanker – Cargo containment
DNV Class Rules: DNVGL-RU-SHIP Pt.5 Ch.7 Sec.23	Liquefied gas tanker – Design with membrane tanks
DNV Class Rules: DNVGL-RU-SHIP Pt.5 Ch.2 Sec.4	Containerships – Gas fuel tank finite element analysis
DNV Class Guideline: CG-0136	Liquefied gas carriers with membrane tanks
DNV Class Guideline: CG-0127	Finite element analysis
DNV Class Guideline: CG-0129	Fatigue assessments

FIGURE 17

Typical arrangement taking into consideration all possible components



3.4.3 Fuel system arrangement

3.4.3.1 Introduction

Natural gas is stored on board as liquid (LNG) and burned by the engine and other consumers as gas. Consequently, a preparation process is necessary to vaporize the liquid and adjust pressure and temperature as necessary for injection into the consumer component.

The gas preparation process differs depending on the main components (tank and engine) installed on board:

- Tank type
  - Type A, B, or membrane type: design pressure of up to 0.7 bar
  - Type C: higher design pressure of up to 10 bar
- Main engine(s)
  - Low-pressure (LP) engine: gas is injected at a pressure of 5–15 bar
  - High-pressure (HP) engine: gas is injected at a pressure of up to 350 bar

General components

- LNG vaporizer: heat exchanger that vaporizes the LNG for low-pressure consumers
- Gas heater: if cold vapour from the tank is used, the gas heater will heat the vapour to the applicable temperature for low-pressure consumers
- LNG deep-well pump or submerged pump: pump inside the cargo tank that increases the flexibility to operate the tank even at low pressure. Also helps with the transfer of LNG from one tank to the other, or back to shore if needed

Components specific to Type C tanks

- PBU (Pressure Build-up Unit): a vaporizer that uses a heating medium to warm up the LNG from the tank, to create vapour. The vapour is then sent back to the tank where it increases the pressure inside the tank to the required level. If a PBU is installed, there is no need for a deep-well/submerged pump.

Components specific to HP systems

- HP pump (typically a piston pump): increases the pressure of the LNG to approximately 350 bar to be used in the main engine
- LNG HP vaporizer: vaporizes the high-pressure LNG
- NG damper: a reservoir of natural gas (NG) to ensure the continuous flow of NG to the main engines

To address the aforementioned safety principles of segregation and double barriers, the several components of the fuel supply system are arranged in dedicated spaces.

3.4.3.2 Dedicated spaces

Tank connection space (TCS)

The tank connection space is a space surrounding all tank connections and tank valves not located on open deck. It may be arranged as an attachment to the tank itself or, alternatively, as a separate space.

Design requirements
- Able to safely contain leakages of cryogenic liquids
- Space boundaries gas-tight towards other enclosed spaces in the ship
- Arranged to prevent the surrounding hull structure from being exposed to unacceptable cooling
- No sources of ignition, e.g. rotating machinery, are allowed to be arranged in this space

Arrangement
- Not located directly adjacent to machinery spaces of category A as defined in SOLAS or other rooms with high fire risk (cofferdam)
- May also be necessary to be arranged for tanks on open deck in order to provide environmental protection for essential safety equipment

Access
- Access arranged as a bolted hatch, unless independent access directly from open deck
- Arranged with a sill exceeding the liquid level, resulting from a calculated maximum leakage of at least 300 mm

Ventilation
- Ventilation arrangements or pressure relief arrangements ensuring that the space can withstand any pressure build-up caused by vaporization of the liquefied gas

Fuel preparation room (FPR)
- The fuel preparation room is any space containing pumps, compressors and/or vaporizers for fuel preparation purposes

Design requirements
- Able to safely contain leakages of cryogenic liquids
- Room boundaries are gas-tight towards other enclosed spaces in the ship.
- Arranged to prevent the surrounding hull structure from being exposed to unacceptable cooling
- May contain rotating machinery
- For rotating shafting passing through room boundaries, permanent gas-tight sealing is arranged

Arrangement
- In general, located on open deck; arrangement below deck may be accepted
- Not located directly adjacent to machinery spaces of category A as defined in SOLAS or other rooms with high fire risk (cofferdam)

Access
- In general, independent and direct from open deck
- Otherwise access through an air lock
- Arranged with a sill exceeding the liquid level, resulting from a calculated maximum leakage of at least 300 mm

Ventilation
- Ventilation arrangements or pressure relief arrangements ensuring that the space can withstand any pressure build-up caused by vaporization of the liquefied gas fuel

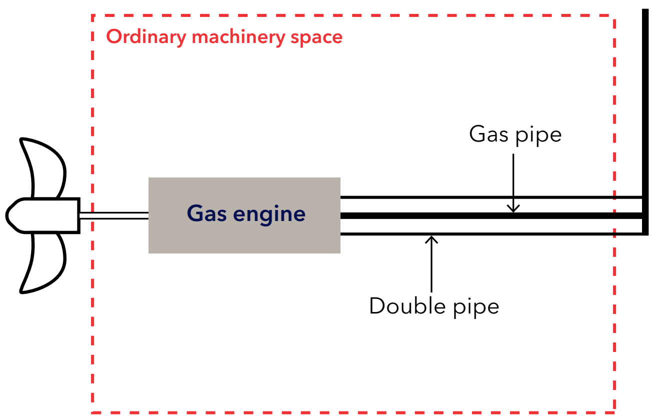
Machinery space
- For machinery spaces containing gas engine(s), specific aspects are to be observed to safeguard the above-mentioned safety principles. To achieve this, one of the following two alternative concepts may be applied:

a) Gas-safe machinery space
Arrangements are such that the spaces are considered gas-safe under all conditions, normal as well as abnormal conditions, in other words inherently gas-safe.

- Fully enclosed, gas-tight double pipes in the engine room, all the way to the combustion chamber
- The room is an ordinary machinery space without any special requirements
- The concept is mandatory for high-pressure piping (> 10 bar), but also suitable for low-pressure installations
- A single failure will not lead to the release of fuel gas into the machinery space because all leakage sources are protected by a secondary enclosure
- More common choice, especially for bigger engine installations

FIGURE 18

Gas-safe machinery space



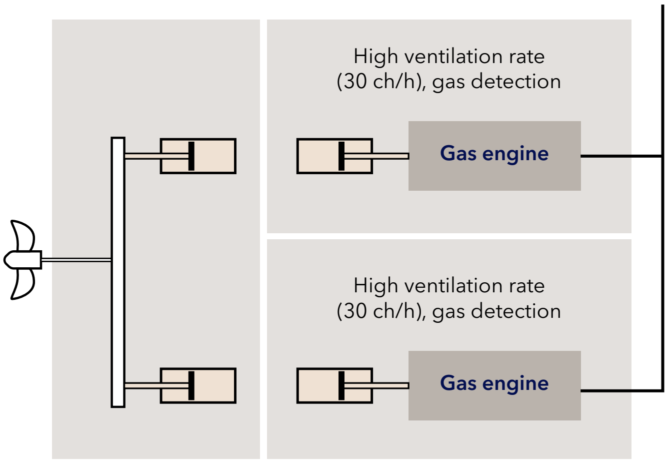
b) ESD-protected machinery space

The machinery space protected by ESD (Emergency Shut Down) is considered gas-safe in the normal mode but changes to gas dangerous on detection of gas.

- A single failure may result in a gas release into the space, e.g. due to single barriers against leakage.
- In the event of conditions involving gas hazards, the ESD of non-safe equipment (ignition sources), including machinery, is automatically executed.
- Leakage detection and extended ventilation requirements, designed to accommodate a probable maximum leakage scenario due to technical failures
- To avoid blackout in case of emergency shutdown in an ESD-protected machinery space, power generation for propulsion and manoeuvring needs to be arranged redundantly in separated rooms independent of each other.
- Separatinge bulkhead spaces need to be able to withstand a local gas explosion in either space.
- Only for low-pressure installations of up to 10 bar
- More typical for smaller vessels with a compact engine room, e.g. up to 600 kW of installed power

FIGURE 19

ESD-protected machinery space



3.4.3.3 Area classification

The purpose of area classification is to identify those areas of the vessel where gas may be present to varying degrees. This serves as input to identify where an ignition source must be avoided or minimized to facilitate the selection of appropriate electrical machinery and the layout of suitable electrical installations. In this way, area classification has an impact on the arrangement of the gas-fuelled ship.

Hazardous areas are divided into Zones 0, 1 and 2 according to IEC standards as shown in Table 6 below:

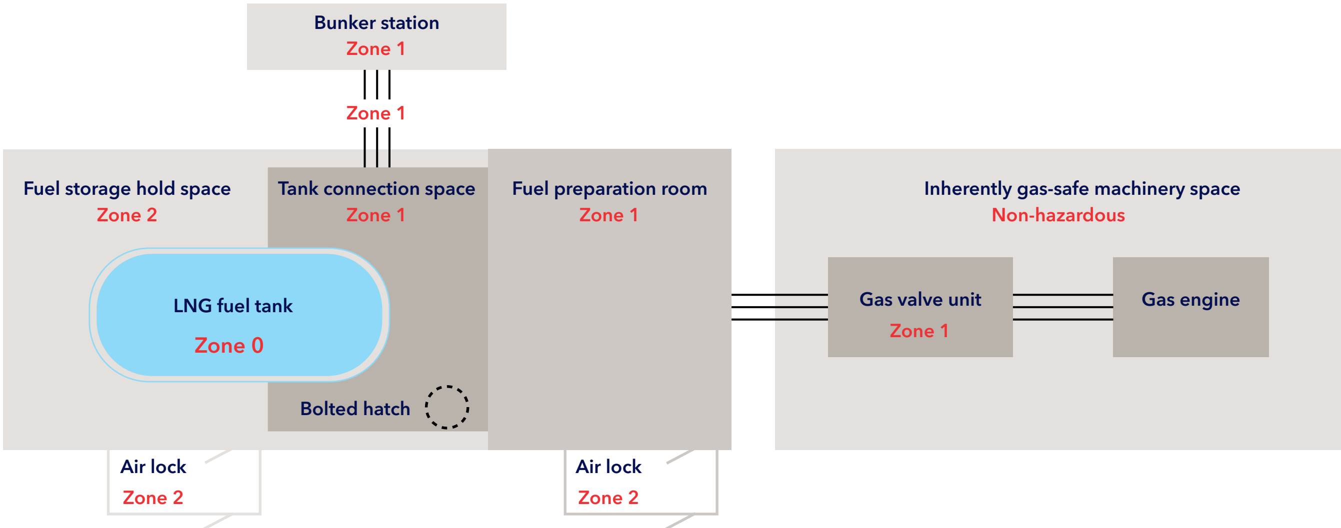
TABLE 6

Hazardous areas

Zone 0	Explosive gas atmosphere … continuously or for long periods	Interiors of gas tanks, pipes and equipment containing gas, pipework for pressure relief or other venting systems for gas tanks
Zone 1	Explosive gas atmosphere … likely to occur in normal operation	1. Tank connection spaces, compressor or pump rooms, double gas pipes, bunkering stations 2. Areas on open deck or semi-enclosed spaces on deck, within 3 m of any gas tank outlet, valve, flange, ventilation outlets from Zone 1 hazardous spaces 3. Areas on open deck or semi-enclosed spaces on deck, within 1.5 m of ventilation inlets and other openings into Zone 1 hazardous spaces
Zone 2	Explosive gas or atmosphere… not likely to occur and for a short period only	1. Air locks 2. Areas on open deck or semi-enclosed spaces on deck, within 1.5 m of surrounding areas of Zone 1

FIGURE 20

Illustrative overview of hazardous zones for a typical gas fuel supply system arrangement



3.4.3.4 Typical arrangements of fuel supply systems

In the following, some illustrative layouts of typical fuel supply systems are shown, depending on the configuration of the main components, in other words the tank and main engine.

FIGURE 21

Vacuum-insulated Type C tank with integrated TCS and low-pressure engine

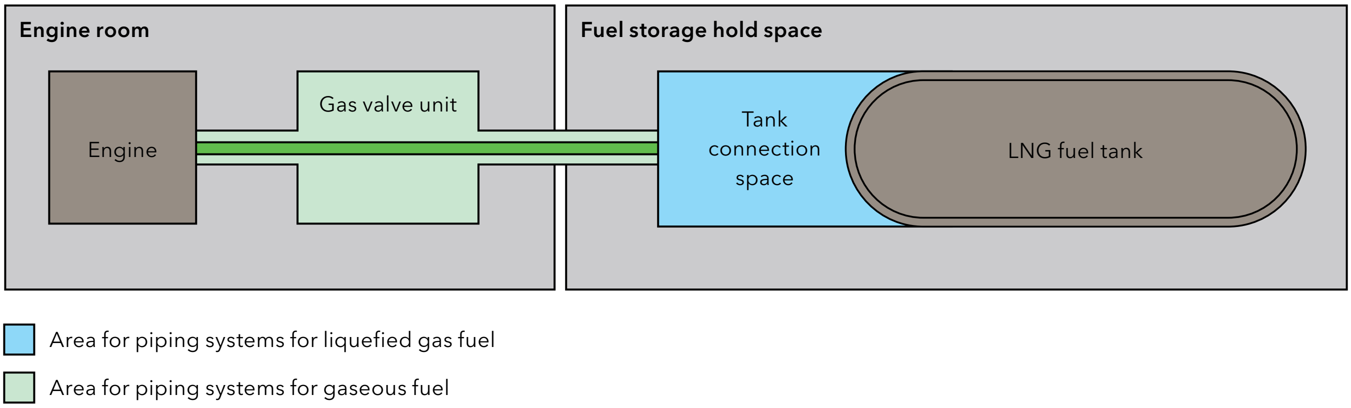
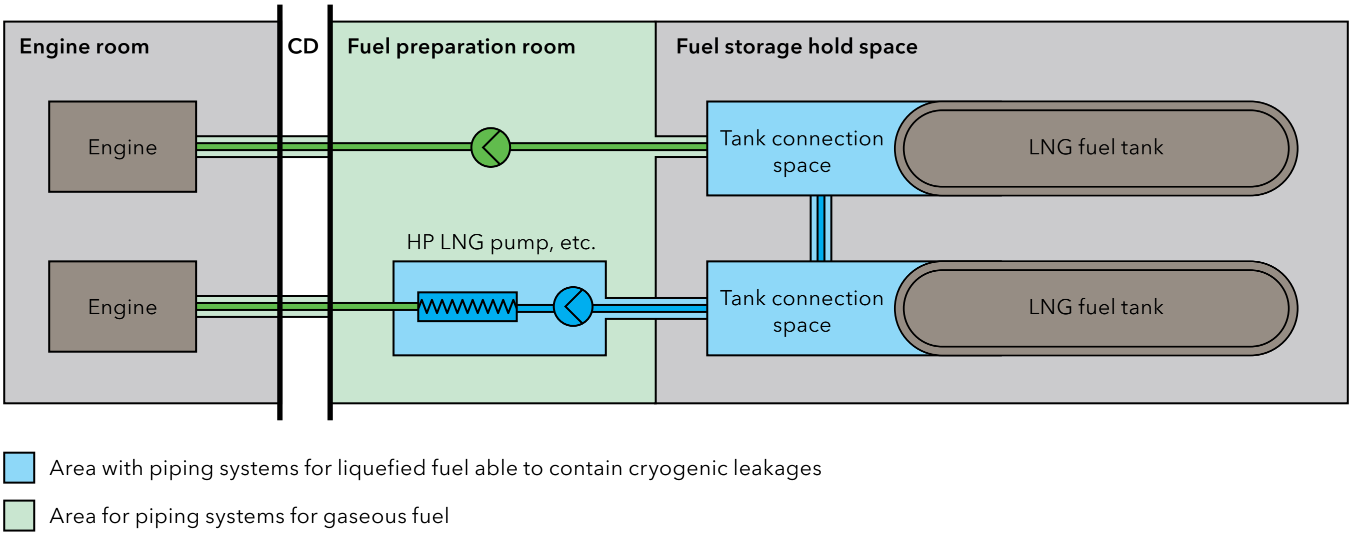


FIGURE 22

Vacuum-insulated Type C tank with integrated TCS and high-pressure engine



a) Vacuum-insulated Type C tank with integrated TCS and low-pressure engine (4–6 bar)

- LNG system with PBU for gas recirculation for pressure build-up
- No rotating components, stable and low maintenance
- Sloshing to be evaluated for stable pressure build-up operation
- Typical for small-sized vessels

b) Vacuum-insulated Type C tank with integrated TCS and high-pressure engine

- Fuel preparation room with all LNG equipment inside separate barrier
- Low-pressure and high-pressure consumers
- Redundant fuel tanks; connection established between TCS
- Typical for medium-sized vessels

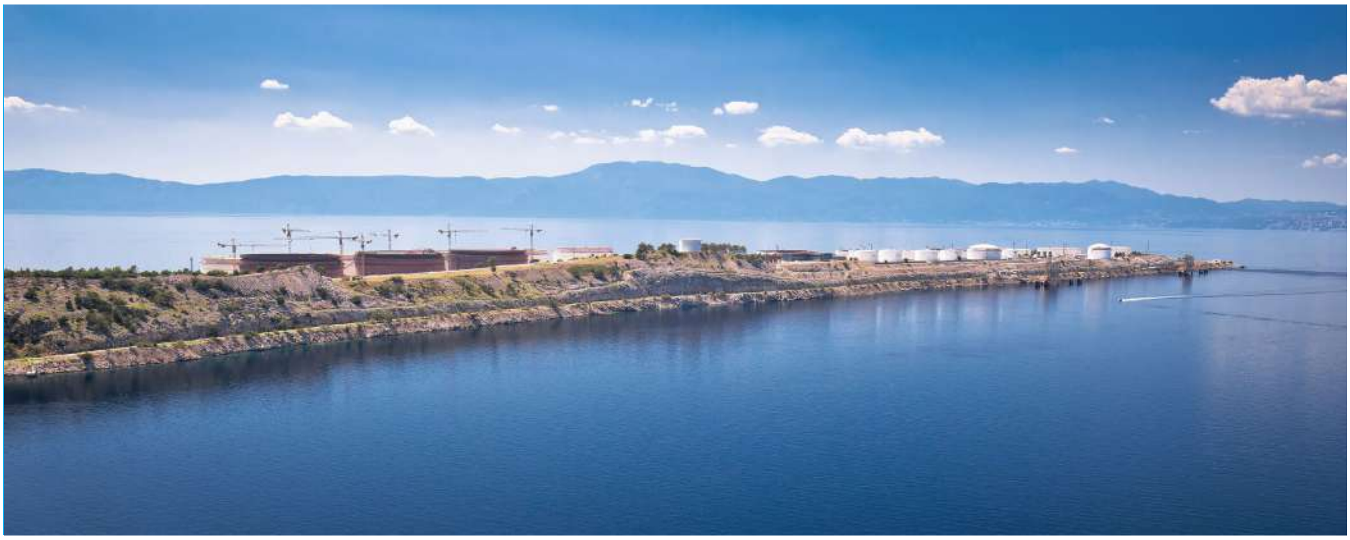
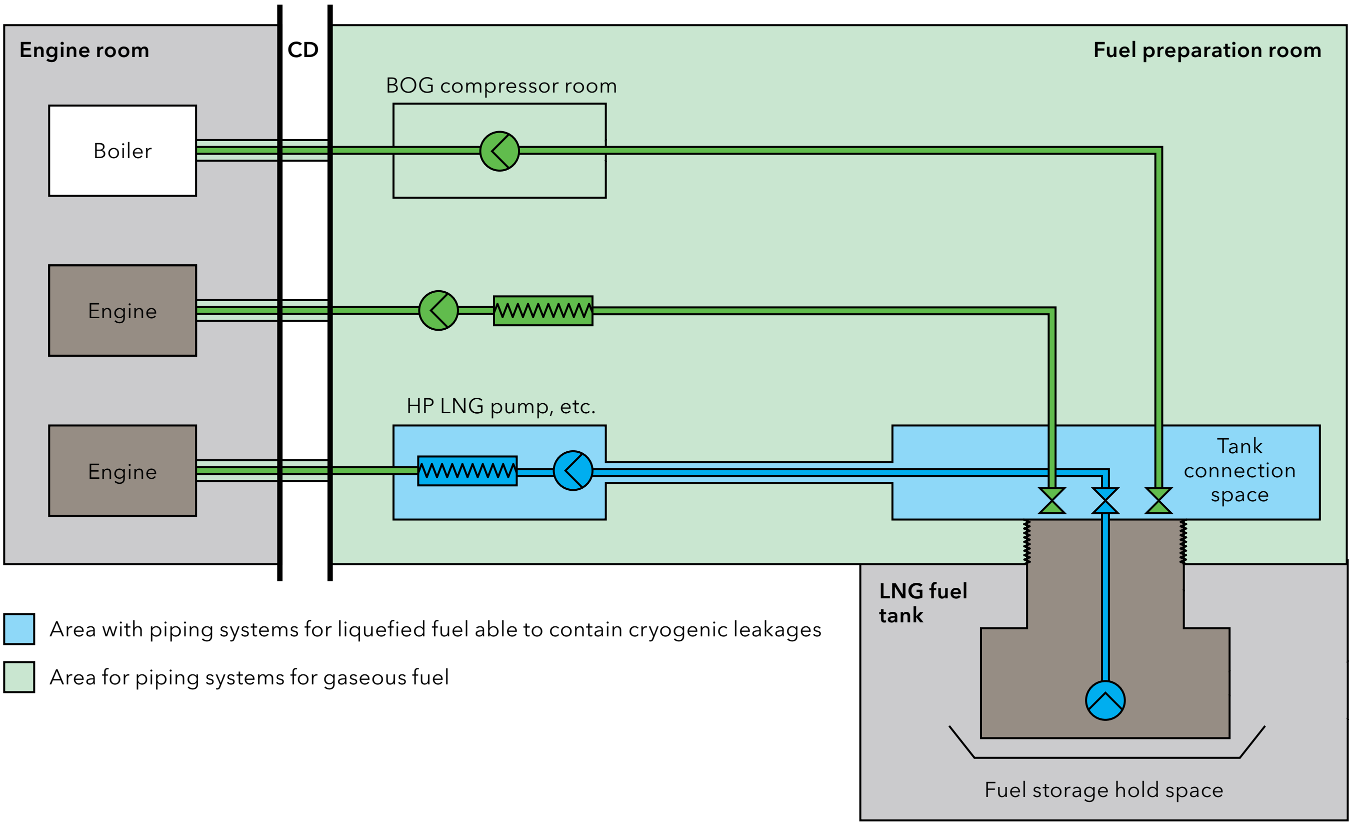


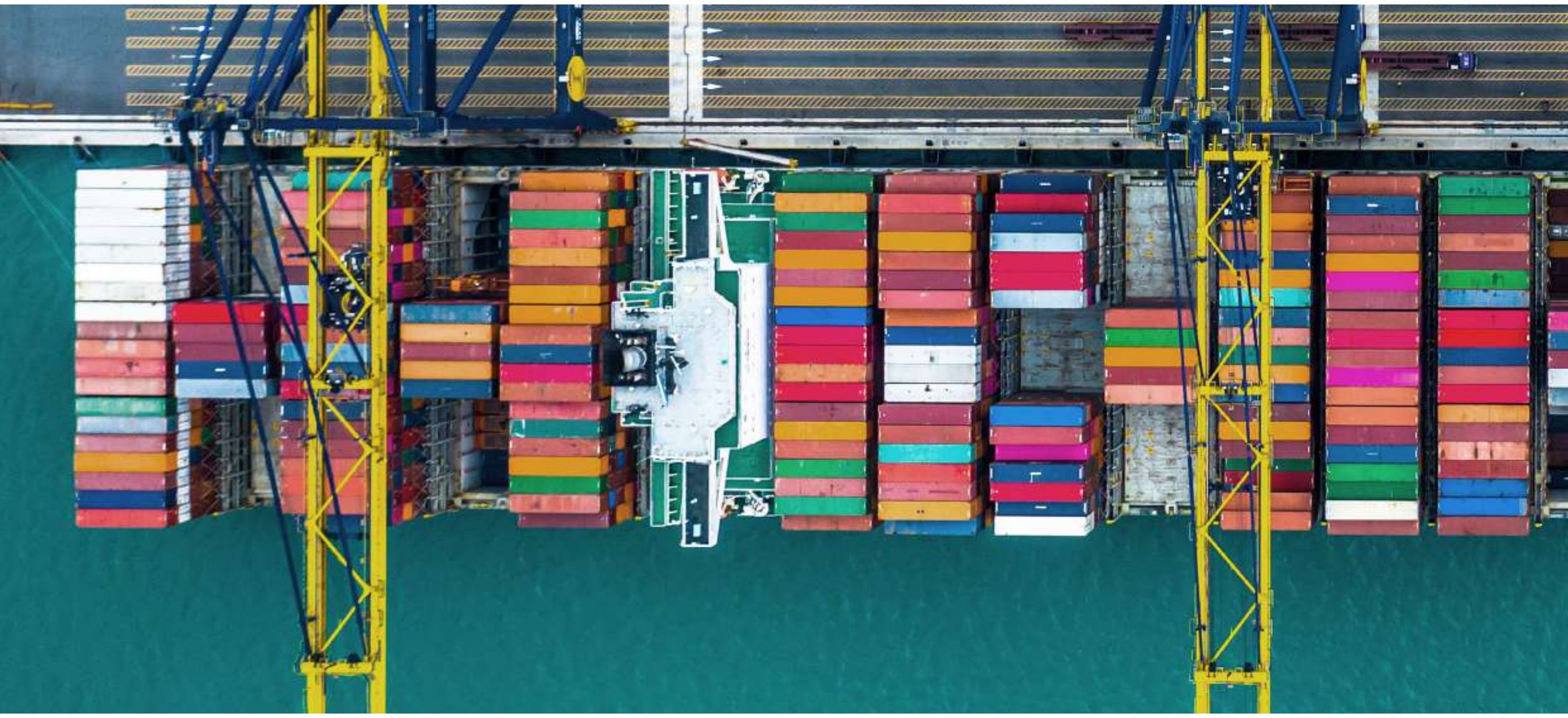
FIGURE 23

Prismatic LNG tank (0.7 bar) with high-pressure main engine (> 350 bar)



c) Prismatic LNG tank (0.7 bar) with high-pressure main engine (> 350 bar)

- Cryogenic HP pump (> 350 bar)
- LNG fuel tank with dome and TCS on top
- Fuel preparation room with all LNG equipment inside separate barrier
- Low-pressure and high-pressure consumers
- Typical for large-sized vessels



3.4.4 Maintenance of fuel storage condition

To remain in the liquid phase, LNG is stored at a temperature around its boiling point at the respective pressure, such as –162°C at around atmospheric pressure. To maintain this low temperature, LNG tanks are isolated, but a minor heat transfer into the LNG can usually not be avoided. As a result, some amount of LNG will vaporize, in other words will be present as boil-off gas (BOG) in the tank space above the liquid level. Depending on the insulation level of the tank system, and on the tank shapes with varying surface areas of the liquid phase, BOG production may vary. A typical figure BOG production is 0.3% of liquid per day as a conservative estimate, depending on tank temperatures, filling level, etc. As BOG accumulates above the fluid level, the pressure in the tank will increase. An important objective is to keep the pressure below the design pressure of the tank.

With respect to regulatory requirements, the topic of maintenance of the fuel storage condition is addressed in the IGF Code as a functional requirement:

"It shall be arranged for safe and suitable fuel supply, storage and bunkering arrangements capable of receiving and containing the fuel in the required state without leakage. Other than when necessary for safety reasons, the system shall be designed to prevent venting under all normal operating conditions including idle periods."

The IGF Code requires the fuel tank pressure to be kept below the set pressure of the pressure relief valves for a period of 15 days without venting gas to the atmosphere.

In this context, various methods for tank pressure control are indicated:

- Energy consumption by the ship (engines, gas turbines, boilers, etc.): in typical system arrangements, boil-off gas may be conditioned to be used as fuel for low-pressure consumers. In propulsion plants with an HP main engine, such consumers may be, for example, auxiliary generators.
- Thermal oxidation of vapours in a gas combustion unit (GCU): the excess boil-off gas is burned, and heat is either used on-board or disposed overboard depending on heat requirements of onboard operations.
- Pressure accumulation: this method is suitable in particular for Type C tanks that are designed to withstand higher than atmospheric pressure. For prismatic tanks of Type A and Type B, as well as the membrane type with a design pressure of max. 0.7 bar, this method is usually not sufficient to control the tank pressure under all conditions.
- Re-liquefaction: convert boil-off gas back into LNG; may be achieved by a dedicated re-liquefaction plant
- Liquified gas cooling: achieved by recirculating LNG via a spray line into the gas phase, which leads to a certain extent of re-liquefaction

Consequently, when specifying an LNG tank and fuel system, it is important to consider the intended operational profile of the vessel, especially operational breaks such as extended anchorage or berthing. Further options and details concerning boil-off gas management can be found under "3.5 Technical design considerations".

3.4.5 Engines

The most common engine types to use natural gas as fuel are summarized below. Important differences between the several engine types are the following aspects:

- Cycle (Otto or diesel)
- Engine type (2-stroke or 4-stroke)
- Fuel suitability
- Pressure of gas supply (low or high pressure)
- Ignition method
- Total GHG emissions (considering methane slip)
- Other emissions
- Sensitivity to gas quality (methane number)
- Suitable for retrofit of existing engines

An important property to consider for the choice of engine is the methane slip, as introduced above. Technically, methane slip originates from gas in the charge air which flows through the cylinder unburned, or from crevices or dead pockets in the combustion area.

3.4.5.1 Engine types

a) Lean-Burn Spark-Ignited (LBSI) gas engine

- Otto cycle
- 4-stroke only
- Natural gas only
- Low-pressure gas supply
- Spark ignition
- High energy efficiency at high load, but some methane slip
- Other emissions low; meets IMO Tier III
- Sensitive to gas quality (methane number)
- Not suitable for retrofit of existing engines

b) Diesel-ignited Dual-Fuel (DF) engine

- Otto cycle
- 2-stroke or 4-stroke
- Multi-fuel capability (LNG/MGO/VLSFO)
- Low-pressure gas supply
- Pilot fuel ignition
- High energy efficiency at high load, but some methane slip – can be reduced by EGR (exhaust gas recirculation)
- Other emissions low; meets IMO Tier III
- Sensitive to gas quality (methane number)
- Possible retrofit of existing engines, but with extensive rebuilding

c) Direct gas injection high-pressure engine

- Diesel cycle
- Only 2-stroke available in the market
- Multi-fuel capability (LNG/MGO/VLSFO)
- High-pressure gas supply
- Pilot fuel ignition
- Maintaining diesel engine performance; low methane slip
- Exhaust gas treatment (NOx) necessary to meet IMO Tier III
- Not sensitive to gas quality (methane number)
- Suitable for retrofit of existing engines

3.4.5.3 Impact of engine selection on GHG emissions

GHG emissions from LNG engines are the sum of CO_2 and CH_4 emissions when converted to theCO_2-equivalent using the Global Warming Potential 100 (GWP100) system. High-pressure engines typically have considerably lower methane emissions than low-pressure designs. In summary, based on 2019 data, the following figures apply for an overall GHG reduction compared with VLSFO, as also summarized in Figure 24:

- **2-stroke engines:**
  - High-pressure: 23% GHG reduction
  - Low-pressure: 14% GHG reduction. It should be noted here that new engine designs launched in 2021 are expected to have much lower methane slip, therefore the reduction will be approximately 17–18%.

- **4-stroke engines (both low-pressure):**
  - Diesel-ignited DF engines with pilot fuel injection: 6% GHG reduction
  - LBSI engines: 14% GHG reduction

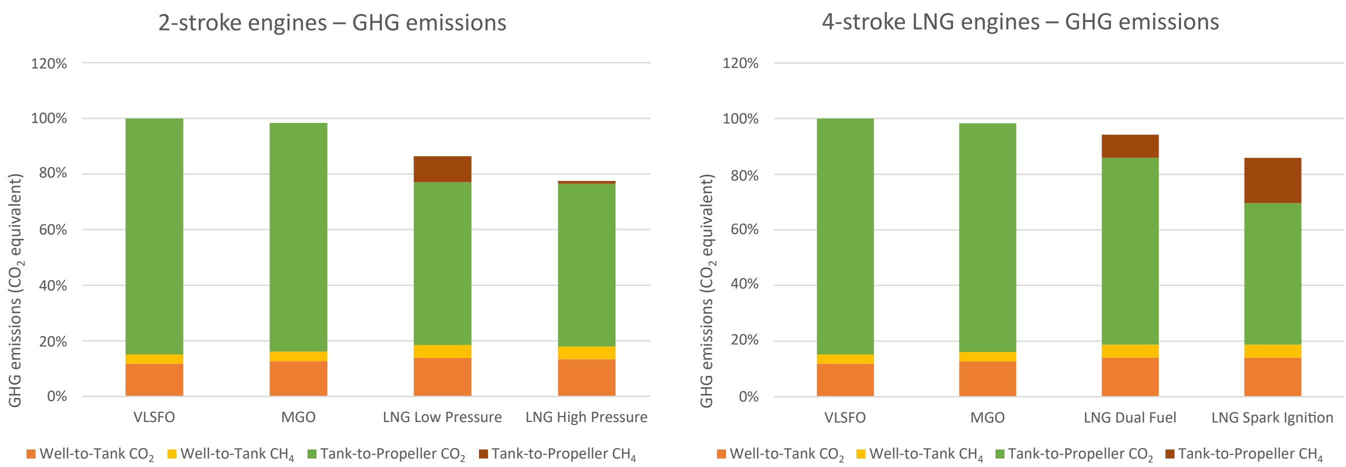
These values are averaged over typical testing cycles. 4-stroke engines typically have higher methane emissions at low engine loads, while for 2-stroke engines, methane emissions do not depend as strongly on the load.

A discussion on regulating methane emissions has already started, and this could be part of future IMO regulations. In this case, engines with low methane slip and/or methane oxidation catalysts (exhaust gas aftertreatment systems as they are under development today) would be favoured.

It becomes evident that the positive impact of LNG being used as ship fuel on the overall GHG emissions will increase when more and more large ocean-going vessels, predominantly using 2-stroke main engines, join the fleet of LNG-fuelled vessels, especially as methane slip characteristics of main engines are expected to be further improved going forward.

FIGURE 24

GHG emissions from various types of LNG engines, including methane emissions using GWP100



3.5 Technical design considerations
This chapter gives guidance on technology selection and dimensioning of components required for LNG to be used as ship fuel. Various aspects are discussed to help make an educated decision for an individual use case. However, as there are more or less strong correlations between individual parameters, no single recommendation can be given for a specific design.

Instead, this document aims to support decisions in the multi-dimensional solution space. A decision support is given at the end of each section, summarizing the most important considerations.

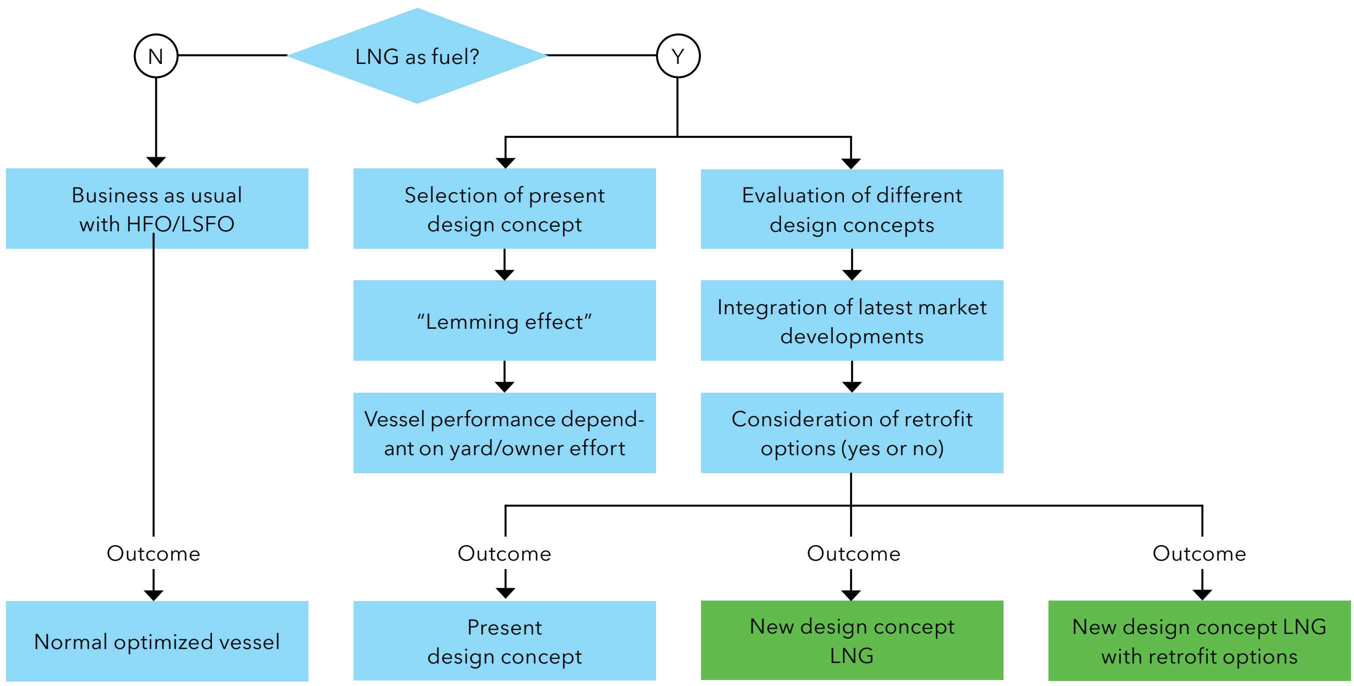
3.5.1 Design approach
When the decision is made that LNG shall fuel a newbuild vessel, there are two basic approaches to the design.

One is to go with an existing design concept. This has the advantage that the yard will have experience in installing the systems, and with operating the system and tuning the various components. This can save building and “tune-in” costs. While such an off-the-shelf approach might be available, and suitable, for a number of use cases, it will also most likely be a compromise between different scenarios aiming at an optimal cost allocation at the newbuild stage. Additionally, alternative fuel technology is developing rapidly, and future regulations may be stricter than currently anticipated. Neither of these trends or possibilities may be entirely reflected by an off-the-shelf design concept.

For finding the most efficient containership for a specific demand (e.g. trade,use case), additional investigations are required prior to selecting a specific design. These investigations include in-depth analysis of the intended trade, technology reviews, feasibility studies, detailed techno-economic analyses of different design alternatives, etc. With respect to a life cycle of approximately 20 years for a container vessel, it may be especially interesting to investigate possible retrofitting options to be able to comply with future regulations once they come into effect. Figure 25 shows a schematic approach for such pre-design investigation.

FIGURE 25

An approach to pre-design investigation of possible retrofit options to comply with potential future GHG reduction regulations for a containership



The final ship design is then typically a result of several rounds of iteration along four main aspects:

- Owner outlines specification based on the pre-design investigation combined with the operational experience of cargo handling and other aspects.
- The design capability of the yard as defined in the building specification and related drawings
- Rules and guidelines of the classification society
- International regulations

Usually, the technical, techno-economic and regulatory aspects of such pre-design studies are not in the focus of yards or the shipowners. Independent third-party consultants such as DNV Advisory may fill the gap here and provide the required expert knowledge.

Not all shipowners may be similarly willing or have the same resources to spend the time and efforts on pre-design investigations instead of relying on an existing design concept. Applying the 75/20/5% cost allocation rule for shipyards (Figure 26) may help to focus on those aspects and components with the highest impact on design and costs.

According to this rule, 10% of the single components account for 75% of the total costs (group A) of a vessel. A further 20% of the components account for a further 20% of the total costs (group B). The remaining 70% of the components account for only 5% of the total cost (group C).

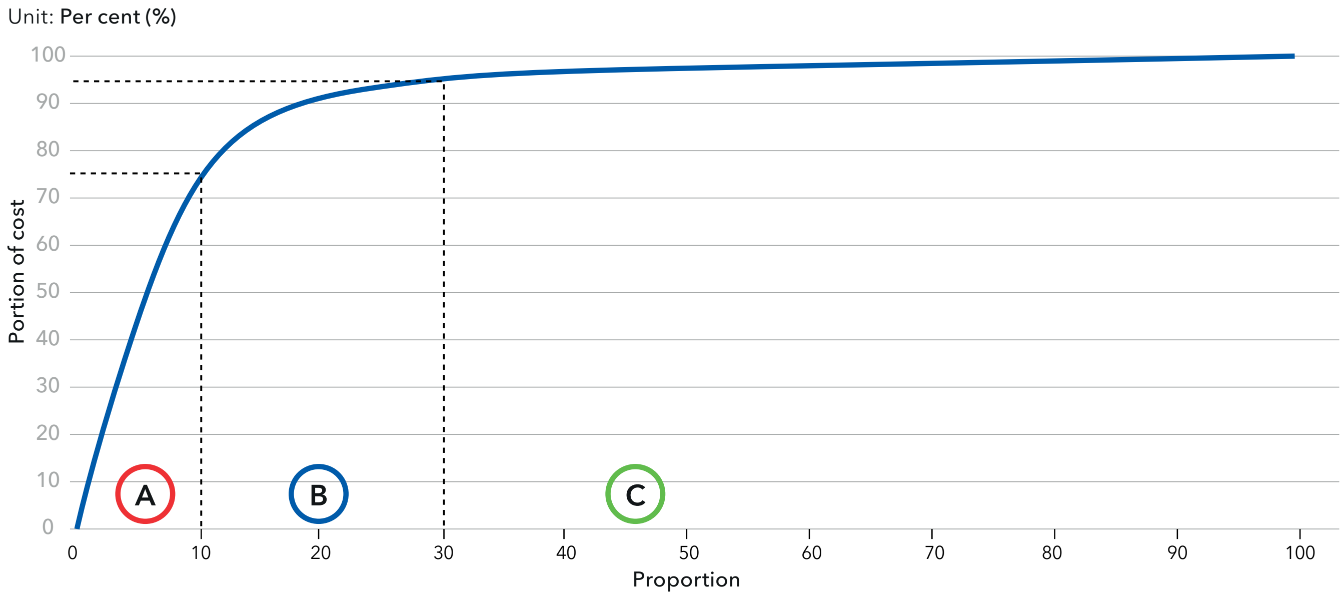
Pre-design investigations should therefore focus on the components in groups A and B only, as they account for 95% of the costs. The main components in these groups are the main engine, propulsion system, LNG tank, gas system, switchboard, and the hull design itself. For these components, detailed pre-design investigations should be carried out to optimize operating expenditure (OPEX) and capital expenditure (CAPEX) with respect to current and future operational and regulatory requirements.

Decision support

- Is an off-the-shelf design available and is it sufficiently suited to the intended use case?
- How much time and effort can be spent on pre-design investigations?
- Which are the components/aspects with the highest cost impact (CAPEX/OPEX)?
- What expertise is available in-house?
- Which aspects require additional external expertise?

FIGURE 26

75/20/5% cost allocation rule



Source: Fischer, Jan O.; Holbach, Gerd (2011). Cost Management in Shipbuilding. GKP Publishing, Cologne 2011.
ISBN: 9783000332258

3.5.2 Fuel tank

ForLNG-fuelled vessels, the largest cost driver will be the tank system, its structural integration and its system integration, including fuel preparation, engineering and certification. For containerships of around 20,000 TEU, the costs of the LNG tank system are estimated to be USD 10–15 million. This accounts for 55–65% of the estimated additional CAPEX for LNG compared with a conventionally fuelled ship. The LNG tank system accounts for approximately 5% of the total cost of the vessel.

For the tank itself, and its structural integration, the two most important aspects concerning CAPEX are the tank type and the tank capacity. Not only do they have a direct impact on, and largely determine, the required labour and material costs. They also strongly influence the choice of required systems, such as for boil-off gas management.

When looking at similar range requirements, the LNG tank capacity needs to be approximately two times larger than that for conventional fuel oil. This is driven by the low volumetric energy density of LNG (22 GJ/m³) compared with MGO (40 GJ/m³) or HFO (42GJ/m³). Due to tank loading limits, the required tank volume needs to be another 2–5% larger than the capacity (see 3.7.2). Tank construction, and restrictions in the arrangement on board (e.g. insulation, tank shape, distances to the hull shell), further increase space demand.

In total, and for the same range, LNG storage requires as much as two to three times more space than storage of conventional fuels. This significantly greater volume reduces capacity for nominal TEU on LNG-fuelled vessels and has a direct impact on the operational costs. Further reduction of cargo capacity may result from the lower gravimetric density of LNG (450 kg/m³ compared with 890 kg/m³ for conventional fuel oil), which limits intake in equivalent load cases (e.g. 14 t equivalent TEU) due to stability requirements.

The effects on cargo capacity can be partially limited by a careful choice of the tank location, especially for two-island containerships. However, when deciding on tank location, the effect of safety restrictions for bunkering operations on loading operations needs to be considered as well.

Decisions on the LNG tank have a large impact on the lifetime costs of a vessel, and careful considerations are required for an optimal balance of CAPEX and OPEX. Establishing the fuel tank requirements is not a simple task, however. Various aspects, which are mostly interconnected, must be considered.

The following sections give guidance on some of the key aspects.

3.5.2.1 Tank capacity

The required LNG tank capacity depends primarily on three major decisions:

- Fuel strategy
- Operational profile
- Bunker strategy

The fuel strategy defines the fuel mix and hence the proportions in which different fuels need to be stored on board. The bunker strategy defines where and how often new bunker will be taken aboard, and the operational profile defines the power demand for which fuel must be provisioned. These aspects largely determine the required tank capacity and are the most important to consider for a newbuild or conversion project.

Fuel strategy

As pure gas engines are not available in suitable sizes, dual-fuel engines are the only viable option today for the main engine of LNG-fuelled containerships. Dual-fuel engines can operate on fuel oil only, or in mixed mode with a minimum required amount of fuel oil as pilot fuel. A pure gas mode is not available, meaning that fuel storage must be provisioned for LNG as well as for conventional fuel oil.

One possible fuel strategy would be to reduce the amount of conventional fuel oil to the minimum required for pilot fuel. This is the best option with respect to GHG and air pollutant emissions, and is the safest option to comply with upcoming and future regulations such as CII. It is expected that a well-designed vessel running on LNG can be used for at least a decade without any adjustments, and up to 20 years if bio-LNG becomes available (see 2.2).

This strategy might also be the most effective option with respect to OPEX, as it benefits most from the price advantage of LNG over conventional fuels (up to 10% compared with HFO and as much as 70% compared with LSFO; see 3.6 “Commercial considerations”). This strongly depends on the short- and long-term development of fuel prices, and needs to be carefully investigated.

However, a maximum LNG fuel strategy requires potentially the largest LNG storage volumes, resulting in high CAPEX. For an analysis of the total cost (CAPEX vs. OPEX) detailed analysis is required and should also factor in potential losses in cargo capacity.

Alternatively, a hybrid fuel strategy could be applied, where LNG is used in environmental control areas only, and a conventional fuel oil is otherwise used. Such a hybrid mode might benefit from smaller required LNG

tank capacities, reducing the impacts on cargo hold space, stability, and initial building costs, but only if a low-sulphur fuel oil is used outside MARPOL-designated Emission Control Areas (ECAs). However, this may come with a large penalty in OPEX, due to the considerably higher price of LSFO/VLSFO.

If sulphur emission limits are to be achieved through exhaust gas cleaning with a scrubber, potential savings in CAPEX due to smaller LNG tank installations are very likely to be offset by the additional cost for a scrubber. Additionally, and depending on their layout, scrubbers may also require large amounts of water being moved through the ship. This may adversely affect stability and equivalent load intake; but most of all, this results in a notable effect on power consumption, increasing OPEX.

Besides the energy required to drive the vessel, auxiliary energy is required for ship operations, for a ship's hotel load and for cargo. Depending on the cargo profile (e.g. the ratio of reefers), up to 20% of the energy demand of the ship could come from auxiliary power demand, adding significantly to the required tank capacities.

Basically, the same considerations as for the main engine apply for auxiliary engines. However, auxiliary engines usually require higher turning rates, and 4-stroke engines are in general being used as auxiliaries. Especially at low engine loads, these engines have a higher methane slip, and future regulations may require additional exhaust gas treatment. Auxiliaries running on LNG generally benefit from lower operating costs, whereas fuel oil generally allows lower CAPEX.

When a fuel strategy for the auxiliary engines is to be established, main engine power take-off should be considered as a very efficient means of producing electrical power. This reduces fuel consumption and emissions. Additional auxiliary engines are then only required for in-port operations, when the main engine is stopped. A hybrid fuel strategy, where some of the auxiliary engines are running on gas and others on a low-sulphur fuel oil, may be quite appropriate here, especially when shore power is also available to cover the auxiliary power demand.

An increasing number of ports are offering shore power for containerships. Depending on the operational profile and the time spent in port and for cargo operations, the use of shore power will noticeably reduce the demand on energy carried as fuel. It is therefore meaningful to factor in shore power supply to reduce tank capacities, but only when considering three important aspects:

- **First, boil-off gas** from the LNG tanks will be continuously produced and needs to be managed. To avoid more expensive options, the tank boil-off rate should be small enough that boil-off production can be balanced by gas-fuelled auxiliary engines providing slightly less than the hotel load. A minimum number of reefers may be factored in here.

- **Second, shore power demand** depends on the cargo profile and the ship size. It can range up to 15% and more of the total power demand. For very large containerships of > 18,000 TEU, this amounts to 5–10 MW. Only a few ports currently offer facilities of this size, and not all ports will offer these facilities in future. Tank dimensioning based on shore power is therefore recommended only if there is sufficient confidence in its availability.

- **Third, a thorough analysis** of the current operational profile, and an educated projection of future changes to this profile, are required to determine with sufficient confidence the effect of shore power supply on the tank capacities.

Decision support

- Is the focus on CAPEX, OPEX or life cycle costs (small vs. large ratio of LNG in the fuel mix)?
- What is the regulatory environment in the short to mid term and over the intended lifetime?
- What is the current and future availability of LNG on the intended trade?
- Can shore power be factored in to reduce LNG storage volume?
- Auxiliary power demand must facilitate boil-off to avoid more expensive BOG management options!

Bunker strategy

Currently, two bunker strategies are common: a single-stop strategy bunkering once per round trip, and a two-stop strategy bunkering twice.

Reasons for a single-stop strategy may be control of the fuel cost and the quality. Bunkering in larger amounts usually reduces logistical costs, as bunker vessels only need to make the trip from the LNG terminal once, and it is more effective to transport larger amounts of fuel. Also, LNG price differences between terminals or regions along the route can be utilized to minimize operational costs. Furthermore, the fuel quality can be more easily maintained with only a single source of supply.

At the same time, bunkering twice per round trip requires significantly lower tank volumes. Compared with a single-stop strategy, this has several advantages:

- Reduced losses in cargo capacity. This includes nominal TEU as well as equivalent load cases as a result of decreased stability due to the LNG tank installation.
- Reduced CAPEX for a smaller LNG tank system
- Reduced boil-off. Although larger tanks have a better surface-to-volume ratio and therefore lower specific boil-off rates, the total boil-off is less for the smaller tank. That leaves more options for BOG management.
- Reduced time for bunkering operations. Simultaneous bunker and cargo handling operations will most likely not be allowed in the bays above the bunker supply ship. Reducing the time for bunkering operations reduces the interference with cargo handling.
- Reduced weathering effects (reduction of fuel quality due to degradation)
- Bunkering of smaller quantities might be easier to organize and could increase flexibility in choosing bunker ports. This applies especially to ultra-large container vessels (20,000+ TEU) where tank capacities of about 20,000 m^3 are required for a one-stop strategy. Bunker supply vessels carrying such amounts of LNG are currently available at only at a few ports.

Generally, the larger cargo capacity and lower CAPEX of a two-stop strategy outweigh potential fuel-cost advantages of the one-stop strategy. It is therefore strongly advised to perform a detailed analysis of the operational profile as well as the CAPEX and potential savings in fuel cost before choosing a one-stop strategy.

It should be noted, however, that bunkering twice per round trip does not necessarily halve the required tank and lost cargo capacities. Bunker ports may not be located at equal distances along the round trip. With a two-stop strategy, tank capacities must be sufficient for the longer of the two legs. Additional margins may need to be provided to allow for future changes of the port sequence and a potentially increased longest leg. Alternatively, instead of the LNG capacity, it may be sensible to moderately increase the pilot fuel tank to provide required margins.

Currently, bunkering more than twice per round trip is usually not considered. Unfortunately, even with a two-stop bunker strategy, LNG tank volumes are still 1.2 to two times as large as the tank volumes for conventional fuel oil on a one-stop strategy (see 3.5.2). This may still severely affect cargo capacity. As LNG infrastructure is building up rapidly, and set-up times may be decreased in future, it may be acceptable to further reduce tank volumes and add additional tank stops in exchange for a maximized cargo capacity.

Decision support

- Evaluate both strategies: bunkering once or bunkering twice per return voyage.
- Conduct an in-depth analysis of the CAPEX and OPEX with respect to the operational profile, the revenue losses due to reduced cargo capacity and the potential gains through cost savings and quality control.
- Can port sequence be optimized to balance distances between bunker ports and maximize the advantage of a two-stop strategy?
- If infrastructure is available – could bunkering more than two times per return voyage be a feasible option to minimize cargo capacity loss and maximize revenue?

Operational profile

A sound understanding and knowledge of the operational profile is required for taking educated decisions on many aspects of an LNG newbuild or conversion project, including tank capacities and the fuel and bunker strategies.

Among other considerations, the operational profile defines the amount of energy required to propel the ship safely along its route and to operate the cargo and maintain its quality over the journey. Together with the fuel and bunker strategies, this defines the volume of fuel that must be stored aboard, and hence the tank capacity. The factors that make up the operational profile include, for example, the number of reefers (deep frozen or fruit storage), number of port calls, port waiting or lay times, the speed-draft profile sailed between the legs, and potential channel waiting times.

Determining the energy demand, and hence the required amount of fuel from the operational profile, usually involves the analysis and interpretation of large amounts of data from various sources. This can be complex and requires expert knowledge in several different domains, such as hydrodynamics and systems analysis. Unfortunately, with LNG (or any other alternative fuel) there is no shortcut to this task. Traditional design approaches with simple specification of range and auxiliary power requirements usually incorporate larger margins to compensate for unknowns in the operational profile. However, with the already very large space requirements for on-board LNG storage (see 3.5.2 and "Bunker strategy"), excessive overcapacities and margins must be avoided. This can only be achieved with an in-depth analysis of the individual operational profile, as this is very specific to the preferences of the liner, the cargo mix and the trade routes. DNV Advisory experts can support this task in many ways, from a high-level establishment of the operational profile and its components to in-depth analysis of on-board measurement data, or predictions of the power demand for propulsion and cargo containment.

Even if ships are operating on similar trades, there can be significant differences in the operational profile, as illustrated by several analyses carried out by DNV in 2019/2020 for container vessels of 18,000+ TEU (see Figure 30). Most of these ships operated on the Asia–Europe trade routes, and only a small fraction was sailing from Asia to the USA and back.

FIGURE 27

Trade routes of ultra-large container vessels in 2019/2020

Almost all trade routes on the Asia–Europe trade routes originated from China or South Korea and were passing through the Suez Canal. Although almost all container liners were calling in western Europe, the routes differed in detail. Some alliances were extending the return voyage to the Baltic; other alliances were calling at Turkey or the Mediterranean ports. In the analysed period, 48 ports were called at in total, but the number of ports called at varied between 10 and 15 for individual voyages.

More than 5,000 port calls have been analysed. The average time in port was 1.41 days for all ports (stays longer than five days were not considered part of normal operation, and were excluded), but for individual ports, that stay was notably longer, such as two days for Rotterdam. When determining fuel consumption and tank capacities, the number of port calls and the port lay times have to be considered. Possible options for inclusion within the fuel strategy, such as shore power, have to be factored in here.

In addition to the port layovers, potential waiting and traffic times at channels have to be considered. Analysis of the 18,000+ TEU vessels showed a passing time of seven to nine hours through the Suez Canal. Southbound waiting times were 12 minutes to 15 hours with an average of five hours. Northbound waiting times were between 45 minutes and 24 hours, with an average of seven hours.

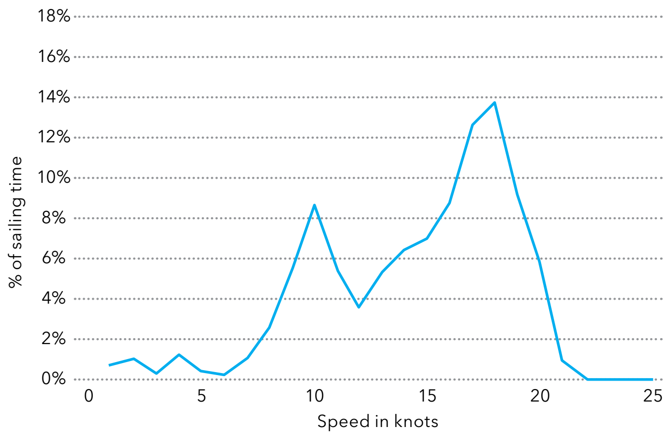
Depending on the ports called at and freight volume, the voyage from Europe to Asia lasts between 33 and 39 days, whereas the return voyage is slightly longer at 37 to 48 days. Distances travelled vary between 11,000 and 12,000 nautical miles (nm) to Europe, and between 11,500 and 12,500 nm to Asia, with the journey in both directions being via the Suez Canal. A (very) few ships have been observed sailing at low speed eastbound around Cape Hope during times of very low freight rates and volumes. The eastbound voyage is considerably longer, with a distance of 14,000 to 15,000 nm.

The vast majority of the fuel carried on board is required for sailing from port to port – mostly to propel the ship but also for auxiliary power. To determine the fuel consumption of the main engine, it is necessary to perform a detailed analysis of the speed/draft profile of the ship while sailing, and to determine the propulsion power demand for various discrete speed/draft combinations. Additions have to be made here if a main engine power take-off (PTO) is installed. Knowing the individual power demand and the specific fuel oil consumption of the engine, the fuel consumption can be calculated for each operational point, as the specific fuel oil consumption is typically specified at ISO conditions from the manufactures. Tolerances need to be added to account for realistic values. The total main engine fuel consumption is derived as a sum of the fuel oil consumption at each individual operational point weighted by its share of the time at sea. On top of that, additional allowances need to be made, for instance for wind and sea state along the route, and for coating deterioration over time.

A speed draft profile is best derived from an AIS analysis of vessels in a suitable peer group, ideally similar-sized ships operating in a similar trade. Figure 28 shows a speed profile and a speed-draft profile for different vessels in the 18,000+ TEU class. The power demand is usually determined by numerical simulations with a digital twin or from a physical test. DNV Advisory offers support and various solutions for these typically very complex investigations.

FIGURE 28

Speed profile and speed-draft profile of vessels in the 18,000+ TEU class



Draft\ Speed	<6 kn	6-8 kn	8-10 kn	10-12 kn	12-14 kn	14-16 kn	16-18 kn	18-20 kn	>20 kn	Total
6-7m	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
7-8m	0.06	0.03	0.05	0.06	0.04	0.01	0.00	0.00	0.00	0.25
8-9m	0.49	0.03	0.16	0.22	0.10	0.04	0.04	0.02	0.18	1.28
9-10m	0.14	0.17	0.17	0.25	0.10	0.07	0.06	0.03	0.01	1.01
10-11m	0.49	0.33	0.48	0.40	0.48	0.48	0.50	0.45	0.16	3.77
11-12m	1.08	0.59	1.30	1.31	1.96	1.04	1.08	0.87	0.48	9.70
12-13m	1.01	0.65	0.85	1.18	1.54	1.64	2.05	2.07	1.01	11.99
13-14m	1.10	0.53	1.16	1.33	1.85	2.54	3.59	2.55	1.17	15.82
14-15m	0.89	0.57	0.74	1.02	1.69	2.57	5.23	6.58	2.20	21.51
15-16m	0.71	0.44	0.84	0.83	1.25	2.70	8.85	13.20	2.94	31.77
16-17m	0.04	0.03	0.06	0.02	0.02	0.11	0.61	1.64	0.35	2.88
Total	6.02	3.38	5.82	6.60	9.04	11.21	22.01	27.42	8.51	100.00

To derive the total fuel demand, the auxiliary fuel consumption must be added. This includes auxiliary fuel consumption for hotel load and propulsion, and for cargo operation. Depending on containership service, the cargo profiles may differ considerably. The main demand for auxiliary power derives from reefer containers and cargo hold ventilation. It is therefore important to assess the number of reefers carried. Differentiation must be made for deep-freeze and fruit reefers. Guidance for calculating the energy demand of reefers is given in DNV's classification rules for ships: Pt.6 Ch.4 Sec.8.

Even though most of the 18,000+ TEU vessels in 2019/2020 operated on a similar trade, there were considerable differences in the cargo profile, port calls, port waiting times and routes sailed. For smaller ships, differences in the operational profile might be even larger. Vessels may operate worldwide or stay in certain regions. Port times or the predominant wind and wave conditions may vary in different regions. Also, the mode of operation may be totally different. For example, small containerships in inner-Asia trade may experience very short port stays, as they might be operated in a "bus" mode taking only the load which is available. Similar ships in Europe are likely to stay in port much longer, waiting for cargo until their bays are filled.

When determining tank capacities, consideration shall also be given to any potential deviations and future changes of the operational profile. For example, future trade routes might change, including the ports called at or the number of ports. The bunker port might change as well; and with a two-stop bunker strategy, this may result in an increased imbalance between the legs, with greater fuel capacity required for the longer leg. Changes to the cargo profile may require increase in reefer capacity, etc.

Typically, to have some margin for variations in the operational profile, tank capacities installed are approximately 15% larger than required. This increases operational safety with moderate increases in CAPEX and OPEX. These reserves can allow some adaptation to future changes to the operational profile. For more significant changes, however likely, their impact on the business model should be assessed before finally deciding on tank size.

Alternatively, if a dual-fuel engine is installed, margins might be included in the fuel oil capacities instead of the LNG capacities. This reduces CAPEX for the LNG tank and allows for maximizing the cargo capacity. However, if the margins are being used, operational cost may increase due to the higher price of fuel oil.

Decision support

- Always conduct an in-depth analysis of the operational profile and the resulting fuel and energy demand.
- The analysis of the operational profile should cover port times, number of ports, speed-draft profile along the trade route, channels, and the cargo profile (reefers, etc.).
- Analysis of the power demand on the speed-draft profile should cover the most important operational points (high power demand, high ratio time at sea) and a reasonable dense sampling. Empirical methods are not sufficient for accurate power prediction.
- Do not forget hull deterioration and weather conditions.
- Will a main engine PTO be used and need to be considered for main engine fuel consumption?
- What is the cargo profile and power demand for refrigerated cargo? Is cargo hold ventilation required?
- How much spare fuel capacities need to be planned? Can pilot fuel capacity be increased for margins?
- Which parameters are how likely are they to change in future? Which scenarios need to be covered by margins?
- Are there measures to further reduce fuel consumption and storage demand (hull form optimization, systems optimization, trim optimization)?

3.5.2.2 Fuel tank type

For ship integration, the CAPEX of tank solutions has to be considered. Depending on the size and type of a tank, the tank costs of an ultra-large, two-island containership will make up about 5% of the newbuild price. Because shipyards might have experience, and licences or contracts, with individual manufacturers and tank solutions, the CAPEX of individual solutions are yard- and tank type-specific. The costs of different tank types and sizes for the same ship at the same yard might vary by a factor of two or three, and might have influence the decision for a preferred solution.

All tank types can be integrated into the ship structure. Membrane tanks are non-self-supportive, with the hull structure supporting insulation and tank membranes. This tank type has the highest requirement for structural support by the steel structure of the hull. As sloshing loads need to be covered by the hull, menbrane tanks have the highest requirements for the hull.

IGF Type C tanks are self-supportive and feature only a few discrete support saddles bringing the loads into the ship's hull. Sloshing loads will be transferred to the saddles. From a structural integration perspective, Type A and Type B tanks are similar to membrane tanks, but with the big advantage of featuring self-supporting tank structures; hence, only parts of the loads are transferred into ship structure with Type A and Type B tanks.

Due to the cryogenic LNG, the tank system will transfer temperature loads to the ship structure. The ship structure must also be capable of sustaining these loads in the event of insulation failures or the failure of one tank barrier. This might require higher temperature grades for the potentially affected steel structure.

The membrane tank utilizes the support of the ship structure. This is the favourable concept in terms of weight and space utilization. Type C tanks are the heaviest and have the lowest space utilization. Bi-lobe or tri-lobe Type C tanks are designed to compensate partially for the space loss.

Loss of payload is the most significant factor for containership design; and here, especially, Type B tanks offer significant advantages. For an Asia–Europe trade and a two-stop bunker strategy, a Type B tank requires about 100–200 TEU less space than an IGF Type C tank. A single bunker strategy will generally be very difficult to realize with a Type C tank.

Boil-off of LNG will result in the need to handle vapour pressure. The boil-off rate will depend mainly on the tank insulation and less on the specific tank type. Insulation design will need to be taken into account when considering boil-off gas management.

Due to the higher design pressure, the Type C tank can accumulate more vapour than a Type A, Type B or a membrane tank. As a result, tank holding times without active pressure control can increase from around a day to up to three weeks. The design pressure of a Type C tank is about 4–10 bar. The higher the design pressure, the thicker the shell of the pressure vessel, meaning the higher the tank weight and costs. The longer holding times offer an advantage in case no active tank pressure management is possible, such as during long port stays without auxiliary engines consuming gas from the vapour phase. For containerships with auxiliary engines consuming gas – and with reasonably short port stay times and electrical power demand from reefers – the fuel gas consumption will not generally require pressure accumulation.

Decision support

- Determine CAPEX of tank and integration costs at your yard.
- Determine lost cargo capacity (weight and dimensions).
- Align with boil-off requirements.

3.5.2.3 Fuel tank location

The tank location is driven mainly by three requirements, two of which are at least partly conflicting: on the one hand, the tank space requirements and, on the other hand, the requirement to lose as little cargo capacity as possible, as well as the minimization of interference with bunkering and cargo operations.

Some of the factors influencing decisions on the tank location include:

- Tank shape: e.g. cylindrical or bi-lobe Type C shapes, and prismatic/trapezoid Type A, Type B and membrane tanks, make it hard or impossible to fit LNG tanks to the rather complex geometry of the aft body.
- IGF Code (Pt.A-1, 5.3): this governs the distance between tanks and the shell plating, the bottom shell plating, and the collision bulkhead. These requirements are either deterministic (giving specific values) or are based on a probabilistic approach following the principles of the SOLAS probabilistic damage stability calculation.
- Inspection spaces outside the tanks are required.
- Tank connection spaces must be enclosed and in the vicinity of the tank.
- The pressure relief system requires a pipe from the tank through all spaces above, which must be far enough from all ventilation openings and must not interfere with cargo handling.

The LNG tank should be located low in the hull to minimize boil-off. Here, the temperatures and ship movements causing sloshing are at their lowest.

Two-island containerships have the highest flexibility with respect to the choice of tank location, and provide the best trade-off between the space requirements and potential conflicts with cargo capacity and operation. Typical tank locations include (see also Figure 29):

- Container bay(s) in front of the engine room. This would reduce capacity of respective holds. Advantages include short piping.
- Container bays above the engine room; again, with the advantage of short piping
- Below the deckhouse. An LNG tank below the deckhouse utilizes space which cannot be used by containers. This helps to minimize the losses in cargo capacity. With small tank capacities, for instance with a two-stop bunker strategy, the space below the deckhouse may even be sufficient to fit the entire LNG tank without losing any cargo capacity. For larger capacities, or if the space below a far forward deckhouse is limited, the cargo bay in front or aft of the deckhouse may be required for additional tank volume. The drawback of this solution is the very long gas pipe length to the consumers. The gas pipes need to be protected and monitored.

A tank location midship between the two islands would also be possible. However, this would maximize cargo capacity losses, and from a structural point of view would induce high global bending moments for a light tank in the section with the highest buoyancy. Typically, this tank location is not considered.

Tank locations behind a machinery island or in front of the deckhouse are typically not possible due to the constraints of space and the complex shape of the hull geometry in these areas.

For single-island containerships, choice of tank location is limited. Typical tank locations include cargo hold space, three to four bays behind the accommodations, or the piggyback bays.

Decision support

- Arrange tank location to minimize losses in cargo the capacity.

3.5.3 Bunkering equipment

The LNG bunkering process imposes restrictions on other simultaneous operations. The position of bunker station and bunker ship mooring will determine how much cargo operations will be disturbed by the LNG bunkering operation.

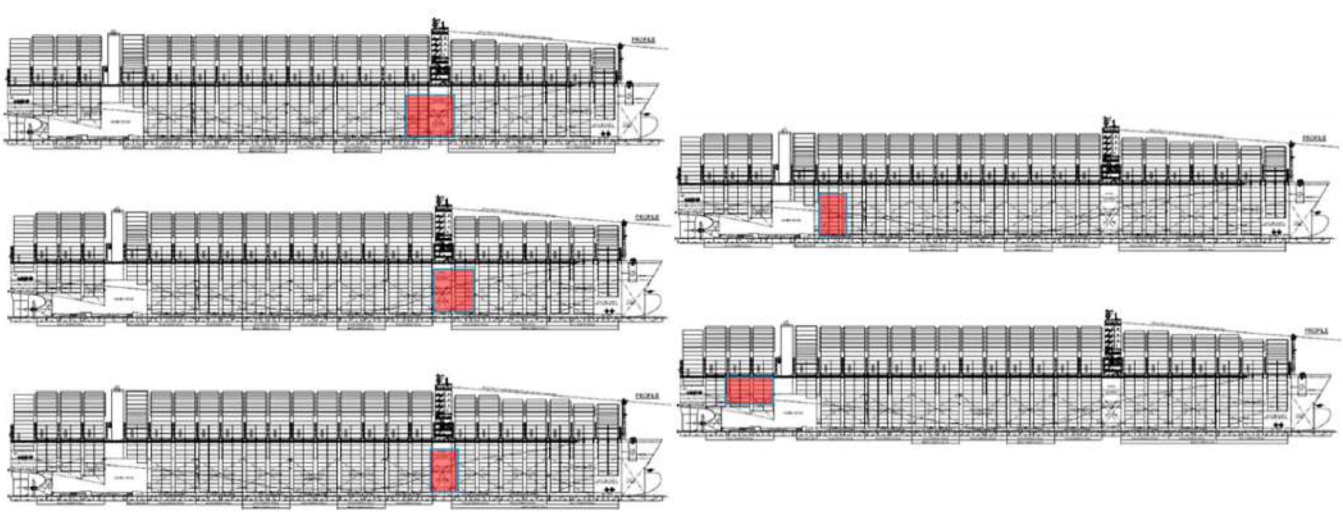
For example, container movements above the bunker ship are not usually allowed. Consequently, to avoid or minimize interference of cargo and bunkering operations, the bunker station should be in an area with lowest cargo capacity, such as the forward or aft. At the same time, safe mooring needs to be provided for the bunker vessel, requiring the bunker station within the parallel midbody. Additionally, the bunker station must be in the vicinity of the tank, as bunker pipes need to be cooled and inerted and hence their length is limited.

The design of the bunker equipment needs to be compatible with that of the bunker supplier, and should allow an efficient bunkering process.

Today, bunkering rates up to 1,600 m³/h are possible on larger bunker supply vessels. Typically, two 8-inch bunker hoses and an additional vapour return line will be used. The bunker equipment should be designed for these bunkering rates in order to minimize bunkering times.

FIGURE 29

Different tank positions within ultra-large container vessel



The bunker station should be above tank level but within operational envelopes of the bunker ship. As the bunker station and the mooring positions for the bunker barge need to be compatible, it is recommended to consult potential bunker suppliers during the design phase.

Decision support

- For the most efficient bunkering process, it is recommended to align bunkering design with potential future suppliers during the ship's design phase.

3.5.4 Boil-off gas management

LNG is stored in tanks at a temperature slightly below its boiling point (–162°C at atmospheric pressure). To maintain this temperature, the LNG tanks are insulated, but a minimal heat transfer cannot be avoided. As a result, some of the LNG vaporizes and will be present as boil-off gas (BOG). This is a continuous process with typical production rates at around 0.1–0.3% of the tank capacity per day. Since BOG must not be released to the atmosphere in normal operation, it requires some management (see also 3.4.4).

Possible options for BOG management

- The energy demand of auxiliary engines for hotel load and cargo containment, such as with reefers, is huge. It is therefore strongly recommended to plan for sufficient auxiliary energy production from natural gas to be covered by BOG production as far as possible. Flexibility and cost benefits make this option the most favourable for BOG management. The required auxiliary capacities for BOG consumption have to be factored in when considering auxiliary power supply from PTO or shore power.
- Using insulation to limit BOG production. The insulation design should be according to the consumers and operational profile. That is, the tank insulation should be designed and fabricated so that the boil-off rate (BOR) of the tank could be used by a generator to supply the energy demand of the vessel in port at berth (hotel load), without or with a minimum reefer load. However, insulation increases costs and requires space.
- Reducing sloshing to limit BOG production. High-sloshing loads generally make it more challenging to design tanks with very low boil-off rates. Hence, sloshing loads need to be minimized. Typically, this is achieved with swash bulkheads in Type A and Type B tanks. For membrane tanks, this can be realized with sloped bottom walls, or by dividing the tank into two separate chambers. Both these solutions result in additional space requirements.
- Sub-cooling of LNG. Installing a sub-cooler involves both additional CAPEX and OPEX but will increase operational flexibility. This is an option to be considered in case other measures are not applicable or less cost-effective.
- Liquefaction of LNG is usually not considered an option. Reasons being high CAPEX and, because of the high energy demand, high OPEX.
- BOG consumption by main engine. Diesel-cycle (high-pressure) engines do not normally consume vapour as fuel gas. This would require high-pressure gas compressors with high complexity, size, weight and costs. This option is valid for low-pressure engines running on Otto-cycle only. However, the main engine is usually not running when the vessel is moored for cargo operations. In such situations, additional methods of managing BOG are required.
- BOG consumption by gas combustion unit (GCU). BOG consumption by a GCU is usually not a good option. LNG-fuelled vessels have a low heat demand, the efficiency of converting heat to power is comparatively low, and dumping the heat from the GCU would be wasting the energy which is contained in the BOG. However, due to the low costs of a GCU, it might be a backup solution for exceptional situations, e.g. maintenance of auxiliary natural gas engines.
- BOG storage. Boil-off gas can be stored as pressurized gas. This can be used as a reservoir for fluctuations in demand, e.g. over a phase of low demand. However, only a Type C tank with the respective pressure ratings can store significant amounts of BOG. Other tank types would require storage of compressed natural gas (CNG) in an extra tank. This involves high technical effort and costs, the reason why this solution is usually not considered.

The chosen BOG management option will depend on the operational profile and the possibility of consuming LNG from the vapour phase, which is generally the most cost-efficient option. The insulation design shall support the BOG management, reducing BOG production to a level which allows its complete utilization for hotel load, and a minimum on reefer containers. For diesel-cycle main engines with auxiliaries not running on gas, additional installations such as sub-coolers might be required for BOG management.

Decision support

- For cost-efficient BOG management, the operational profile and all operational modes should be evaluated with respect to BOG consumption.
- If holding times for given technical solutions cannot be assured by pressure accumulation, sub-cooling might be an option. However, costs for sub-cooling might be higher than pressured tank and insulation.
- The insulation of the tank should be designed and fabricated so that, under any circumstance, the BOR of the tank could be used by a generator to supply the energy demand of the vessel in port at berth (hotel load), without any reefer load (minimum reefer load shall be specified).
- BOG handling should always be reviewed for the first vessel of every series.

3.6 Commercial considerations

The main benefits of LNG-fuelled containerships are economic and environmental performance. In this chapter, some aspects are given which should be considered in the evaluation of CAPEX, OPEX and EEDI.

Price indications are given for the example of a 20,000 TEU container vessel. With a comparatively conservative fuel price model, the higher investments when choosing LNG as main fuel have a payback time of approximately seven years only, compared with an HFO vessel with scrubbers. Compared with LSFO as main fuel, payback time would be even significantly shorter. This means that total costs (CAPEX and OPEX) are smaller compared with HFO/LSFO after seven years or less.

3.6.1 CAPEX

Capital expenditure (CAPEX) is the funds spent to acquire, maintain and upgrade physical assets, such as ships. It is considered a capital expenditure when the asset is purchased new, or when funds are employed to extend the useful life of an existing asset.

Benchmarked against traditional ships, CAPEX will increase for LNG-fuelled containerships. Major contributions include:

- The LNG tank system. The largest cost driver will be the LNG tank system, its structural integration, and its system integration, including fuel preparation, engineering and certification. This is only compensated to a small degree by simplification of the conventional fuel system (for indicative purposes only: USD 10–15 million in additional costs)
- Engine costs. The second largest cost driver is the more expensive main and auxiliary engines for the LNG-fuelled containership (for indicative purposes only: USD 3–8 million for main engines and USD 3–8 million for auxiliary engines).
- BOG handling equipment. While gas combustion units are reasonably cost-efficient, a sub-cooler or even a re-liquefaction unit would add considerably to the CAPEX.

Cost savings might apply for abatement technologies, fuel oil systems, and tanks (e.g. abstaining from scrubbers would save USD 4–8 million). Other costs might add up due to the need for bunker stations, vent systems, ventilation, inerting/nitrogen system, air locks, ATEX equipment, etc.

Decision support

- In total, approximately 10% more CAPEX is expected to be required for an LNG-fuelled ship, but this is very dependent on the individual design options and yard.

3.6.2 OPEX

Operating or operational expenditure (OPEX) is the ordinary expenditure required for the day-to-day operation of a business, or a system such as a ship. For larger systems like ships, OPEX also includes the salaries and pension costs of workers and facility expenses such as rent, property taxes, and utilities.

Besides the environmental benefits, reduced OPEX is the main advantage of running a ship on LNG. An ultra-large, two-island containership has an energy consumption of about 500,000 MWh/a (+/–20% depending on the operational profile). This is equivalent to approximately 45,000 t of HFO. Depending on the fuel price scenarios, considerable savings in OPEX are possible.

This document will not promote any fuel price models or prediction. However, to highlight the importance of fuel price assumptions, the following example suggests that the LNG fuel costs might be USD 3.7 million less than sailing on VLSFO (<0.5% S) or USD 0.8 million less than sailing on HFO. This is only indicative and is oversimplified, which means it does not consider any emission reduction costs for HFO, nor any costs for Ultra-Low Sulphur Fuel Oil (ULSFO) or pilot fuel. Specific consideration of OPEX accounting for actual operational profile and updated price information is indispensable.

TABLE 7

Fuel costs for ultra-large containerships (oversimplified and illustrative)

Fuel	USD/t	USD/MWh	USD million per 500,000 MWh
IFO380	350	31.3	15.7
VLSFO	430	37.6	18.8
LNG TTF		24	
LNG-free ship		30.2	15.1

Key: IFO380 = Intermediate Fuel Oil 380; LNG = liquefied natural gas; MWh = megawatt hours; t = tonnes; TTF = title transfer facility; VLSFO = Very Low Sulphur Fuel Oil

The LNG-fuelled ship will benefit from reduced GHG emission costs. Based on an energy demand of 500,000 MWh, costs for CO_2 are indicated in Table 8 for different fuels. With LNG, these costs will decrease by approximately USD 0.9 million per year, assuming a CO_2 price of USD 25 per tonne of carbon dioxide.

TABLE 8

CO_2 costs for ultra-large containerships (oversimplified)

Fuel	tCO_2/a	USD million @ 25 USD/tCO_2	USD million @ 50 USD/tCO_2	USD million @ 100 USD/tCO_2
IFO380	139,000 (500,000 MWh/a * 3,114 tCO_2/tFuel; 40,200 GJ/t * 3,600 GJ/MWh)	3.5	7	13.9
VLSFO	138,000 (500,000 MWh/a * 3,151 tCO_2/tFuel; 41,200 GJ/t * 3,600 GJ/MWh)	3.5	6.9	13.8
LNG	103,000 (500,000 MWh/a * 2,750 tCO_2/tFuel; 48,000 GJ/t * 3,600 GJ/MWh)	2.6	5.2	10.3

Key: tCO2 = tonnes of carbon dioxide; GJ = gigajoules; IFO380 = intermediate fuel oil 380; LNG = liquefied natural gas; MWh = megawatt hours; /a = per annum; t = tonnes; tFuel = tonnes of fuel; VLSFO = Very Low Sulphur Fuel Oil

The considerations on fuel price and CO_2 emission costs do not include any scenarios with biofuels or carbonneutral synthetic fuels or fuel blends. OPEX considerations of such scenarios are very likely to be to the benefit of an LNG-fuelled ship. Bio-LNG or synthetic LNG could be used or blended in with no or only minor modifications of the ship's systems. The biggest advantage might be that a target CO_2 emission rate could be reached for an LNG ship with a much lower blend ratio of expensive biofuel or synthetic fuel compared with a blend-in solution for an oil-fuelled ship. All scenarios, including low target CO_2 rates, will result in high commercial benefits for LNG-fuelled ships.

Additionally, less dominant operational cost factors (annual where example figures are given) include:

- Manning, because LNG ships require additional qualifications: < USD 50,000
- Insurance costs: may increase due to increased ship value
- Repair and maintenance of engines: < USD 500,000
- LNG-related spares might be more expensive: > USD 500,000
- Sludge and NaOH savings for LNG ship: < USD 500,000
- Additional management costs: < USD 50,000
- Additional dry-docking costs due to tank inerting and warming up: USD 500,000 per five years

These costs are purely indicative and need to be evaluated for each individual business case.

Decision support

- For OPEX, the fuel price assumptions will have the largest impact on the business case of the gas-fuelled ultra-large containership. Decisions on LNG as fuel are very sensitive to the decision-maker's fuel-price model. Operators believing in future high carbon pricing will also highly appreciate the positive impact on the business case. Other major OPEX increases are identified and will have a noticeable, though less relevant, impact on the fuel decision.

3.6.3 GHG regulations

The fuel will have a direct impact on the conversion factor for fuel oil. MEPC.281(70) defines the conversion factors, cited as tonnes of carbon dioxide per tonne of fuel (tCO_2/tFuel), as: MGO = 3,206, VLSFO = 3,151, HFO = 3,114 and LNG = 2,750; a reduction in carbon intensity of about 12% compared with HFO. When also considering the higher energy content of the fuel oil and the used pilot fuel, the EEDI for an LNG-fuelled ship can be about 25% lower than the EEDI of its conventionally fuelled sister ship. For more background information on EEDI/EEXI, please see 2.1 "Initial IMO GHG strategy".

The same applies to the Annual Efficiency Ratio (AER). Following MEPC 75, the IMO requires an energy-efficiency improvement and decarbonization plan, and after 2023, ships will need to implement corrective actions if they are given D or E carbon-intensity ratings. The AER is also

EQUATION 1

EEDI

$$\text{EEDI} = \frac{\text{Engine load kW} \cdot \text{Specific fuel consumption} \cdot CO_2\,\text{factor}}{\text{Design speed} \cdot \text{Deadweight}}$$

EQUATION 2

Annual Efficiency Ratio (AER)

$$AER(ME, v, t, fuel\ type) = \frac{\sum_{i=vmin}^{vmax} \alpha . v_i^{\beta} . t_i . f_{Co2}(fuel\ type)}{\sum_{i=vmin}^{vmax} v_i \ . t_i \ . dwt}$$

proportional to the conversion factor for fuel oil, allowing an AER reduction for the same operational profile of about 25% for LNG, which opens up flexibility for the LNG-fuelled ship and operational and cost advantages in future.

EEDI and conversion factors for less carbon-intense fuels are defining the essential preconditions for reaching a targeted Carbon Intensity Index (CII). An LNG-fuelled ship qualifies for a lower CII and more operational flexibility. During a ship's life cycle, fewer operational limitations, such as speed reductions or requirements on the use of biofuels or synthetic fuels, may be imposed on the LNG-fuelled ship.

Decision support

- Company carbon intensity targets, costs for compensation measures, and the vessel's and company's sensitivity to operational measures shall be considered when deciding between a conventional or LNG-fuelled ship.

3.7 Bunkering technology

3.7.1 General aspects of LNG bunkering

LNG bunkering operations differ from the conventional bunkering of oil fuels, which have flash points above 60°C. Bunkering of LNG requires compatibility of bunker suppliers and the vessel to be bunkered. In addition, dedicated processes and procedures have to be in place. Today, large bunker ships allow bunkering rates of about 1,600 m^3/h.

The LNG transfer system should be designed to carry out the LNG bunkering efficiently and safely. The basic criteria to establish or design such a system is to avoid any kind of release to the atmosphere. In case of a leakage of gas or LNG, the vapour shall be safely vented away from sources of ignition. Any leakage from supplying facilities or receiving vessels of natural gas or LNG should be efficiently detected.

Bunkering options

There are different options for how LNG is distributed to the receiving vessel to be bunkered. The LNG volume of the tanks on the receiving vessel, the available time for the bunkering operation, and the port infrastructure are only some of the factors influencing the choice of bunker solution. The following bunkering options have been established:

- Ship-to-ship LNG bunkering
- Truck-to-ship LNG bunkering
- Terminal-to-ship LNG bunkering
- Portable LNG tank-to-ship

Ship-to-ship LNG bunkering

This the most desirable solution, as LNG can be transferred in large volumes while at anchorage or berth. The maximum bunkering rate depends on the size of the hose and the limitation on transfer rate, which is recommended by the manufacturer to reduce the risk of cavitation. The capacity of the available bunker vessels is mainly in the range of 1,000m^3 to 10,000m^3. Most of the vessels can realize a bunkering rate of 1,000 to 2500m^3/h. Bunker vessels are equipped with systems to handle the boil-off gas as vapour return from the receiving vessel.

Truck-to-ship LNG bunkering

Transporting LNG by truck to the receiving vessels is a very flexible solution. But the amount of LNG that can be transported this way is limited to approximately 40 m^3. The quantity required to supply the ship may need more than one truck. The duration of bunkering depends on the transfer rate of the truck (which is in the range of 90 m^3/hour). Different arrangements on the shore side are possible so that multiple trucks can supply LNG simultaneously. This method is most suitable for vessels with a rather small quantity of LNG required. In Europe, the European Agreement concerning the International Carriage of Dangerous Goods by Road (ADR) regulates the construction, equipment and use of vehicles for the transport of hazardous material – in this case for the LNG truck. Similar requirements are in place elsewhere in the world.

TABLE 9

Summary of advantages and disadvantages of the different bunkering options

	Ship-to-ship	Truck-to-ship	Terminal-to-ship	Portable tanks
Advantages	• High flexibility • High bunkering rates • High bunkering volume • Bunkering directly at berth	• Bunkering directly at berth • Low investment	• High tank capacity • Fast bunkering	• Fast bunkering • Utilization of existing logistics
Disadvantages	• High investment	• Low bunkering rates • Low volumes	• Fixed location • High investment	• High costs of fuel storage • Low space utilization of fuel storage

Terminal-to-ship LNG bunkering

The ship is bunkered through a dedicated bunkering facility such as a terminal or jetty. The terminal is connected to the ship through rigid pipes via flexible hose, or using a loading arm. The bunkering rates are high, and large volumes can be transferred in a short time.

Portable LNG tank-to-ship

The ship is bunkered by the exchange of a portable tank system. This tank systems could be 40-foot ISO standard containers or standard trailers, or any other solution that can be safely handled by an efficient logistics. Bunkering will consist of the handling of the LNG tank container, and the connection procedure. As there is no LNG flow involved, the bunkering times depend on the handling of the tank and on the connection procedure.

Loading arms and hose arrangements

Loading arms or transfer hoses can be used for transferring LNG. Depending on the bunkering option, transfer hoses are currently the preferred solution. Hoses and loading arms are designed to withstand the cryogenic temperatures occurring during the bunkering process. Different loads have to be taken into consideration for the design of hoses and loading arms. These result from relative motions of the vessel, from the weight, including the weight of the liquid and pipe, and ice which arises during the bunkering operations. LNG hoses comply with industry standards such as EN1474-02, EN 1474-3 and EN 12434.

The following types of couplings have been established for transfer operations of LNG-fuelled vessels:

- Dry Disconnect Coupling (DDC)
- Emergency Release Coupling (ERC)
- Powered Emergency Release Coupling (PERC)

DDC is also known as dry connect/disconnect coupling used as a hose connection device. The DDC coupling automatically seals off both hose and fixed pipe end when the hose is disconnected. The DCC is designed as per ISO standards (ISO 2159:2019) and consists of tank unit and hose unit. The design may differ as per different original equipment manufacturer (OEM), hence couplings from two different OEMs may not fit together even if they are designed as per ISO standards.

In order to safeguard the bunkering operation, an **ERC** activates its safety feature when pulling forces are applied on the hose. The coupling has an adjustable breaking point which can be aligned with the desired pulling force. The valves inside the coupling automatically close on both sides and stop the LNG supply if the breakaway coupling separates due to pulling forces, such as a departing bunker vessel.

The **PERC** is integrated into the ESD (Emergency Shut Down) systems and disconnects automatically with activation of the ESD. The internal valves of the coupling close automatically and hence stop the LNG supply. The coupling also acts as breakaway coupling providing dual functions and increased safety. The PERC can be operated hydraulically or pneumatically.

In addition to the transfer system, the bunker supply facility and the receiving vessel shall be equipped with an ESD system. The bunker source and the receiving vessel are connected by an SSL (Ship Shore Link) system that connects both systems with each other. Triggering of the ESD system from either the supplying or receiving side activates the ESD measures on both sides. This relates mainly to valves, pumps, and other equipment used for the bunkering operations. The ESD is activated manually or automatically in case of gas detection, fire risk or any other hazardous situation.

Relationship with other specifications, guidelines and standards:

- ISO/TS 18683 Guidelines for systems and installations for supply of LNG as fuel to ships: this is a technical specification that provides guidance on the planning, design and operation of LNG bunkering facilities, along with applicable industry standards for system design to ensure a high level of safety, integrity and reliability. Note: The standard is reviewed every five years and was published in January 2015. It will be replaced by ISO/AWI TS 18683, which is currently under development.
- Recommended Practice DNVGL-RP-G105 – Edition October 2015, Development and operation of liquefied natural gas bunkering facilities: this provides guidance to the industry on development, organizational, technical, functional and operational issues in order to ensure global compatibility and secure a high level of safety, integrity and reliability for LNG bunkering facilities.
- ISO/TS 16901 Guidance on performing risk assessment in the design of onshore LNG installations including the ship/shore interface: this provides recommendations for risk assessments of the planning, design and operation of LNG facilities onshore and at the shoreline, using risk-based methods and standards.
- ISO 20519 Ships and marine technology – Specification for bunkering of LNG-fuelled vessels. This is a standard initiated by the IMO and sets requirements for LNG bunkering systems and equipment that are not covered by the IGF Code.
- The SGMF (Society for Gas as a Marine Fuel) safety guidelines for the bunkering of gas as marine fuel: these aim to give the different parties involved a common understanding of the LNG bunkering operations through recommended procedures, checklists, and technical and organizational guidance.
- SGMF LNG Bunkering Guidelines Version 2: this publication provides guidance to all the parties directly involved in the bunkering of ships with LNG. It aims to ensure that natural-gas-fuelled ships are re-fuelled with the highest levels of safety, integrity and reliability. These guidelines recognize that there are potential differences in cultures and understanding between suppliers and users of natural gas as marine fuel that do not exist in the wider LNG transportation industry.
- ISO 28460:2010 Petroleum and Natural gas Industries – Installation and Equipment for liquefied natural gas–ship-to-shore interface and port operations: this specifies the requirements for ship, terminal and port service providers to ensure the safe transit of an LNG carrier (LNGC) through the port area and the safe and efficient transfer of its cargo. Note: ISO 28460:2010 applies only to conventional onshore LNG terminals and to the handling of LNGCs in international trade. However, it can provide guidance for offshore and coastal operations.
- IACS REC 142 LNG Bunkering Guidelines: this guideline provides recommendations for the responsibilities, procedures and equipment required for LNG bunkering operations, and sets harmonized minimum baseline recommendations for bunkering risk assessment, equipment and operations.

3.7.2 Tank loading limits

Tank filling is limited to a lower and an upper value to ensure that a minimum amount of liquid phase or, respectively, a minimum of the gaseous phase, remain in the tank. Depending on the tank construction, these tank utilization limits mean the tank volume needs to be 2–5% larger than the required capacity. The loading limit of LNG fuel tanks is typically between 85% and 95% of the tank volume. It depends on the tank type, pressure relief valve setting, and other factors.

FIGURE 30

Tank loading limits

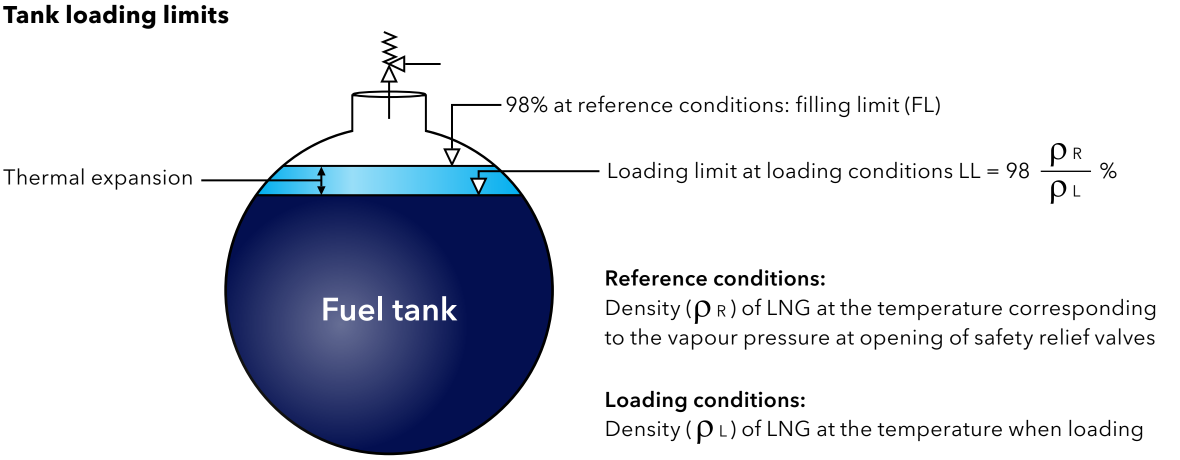
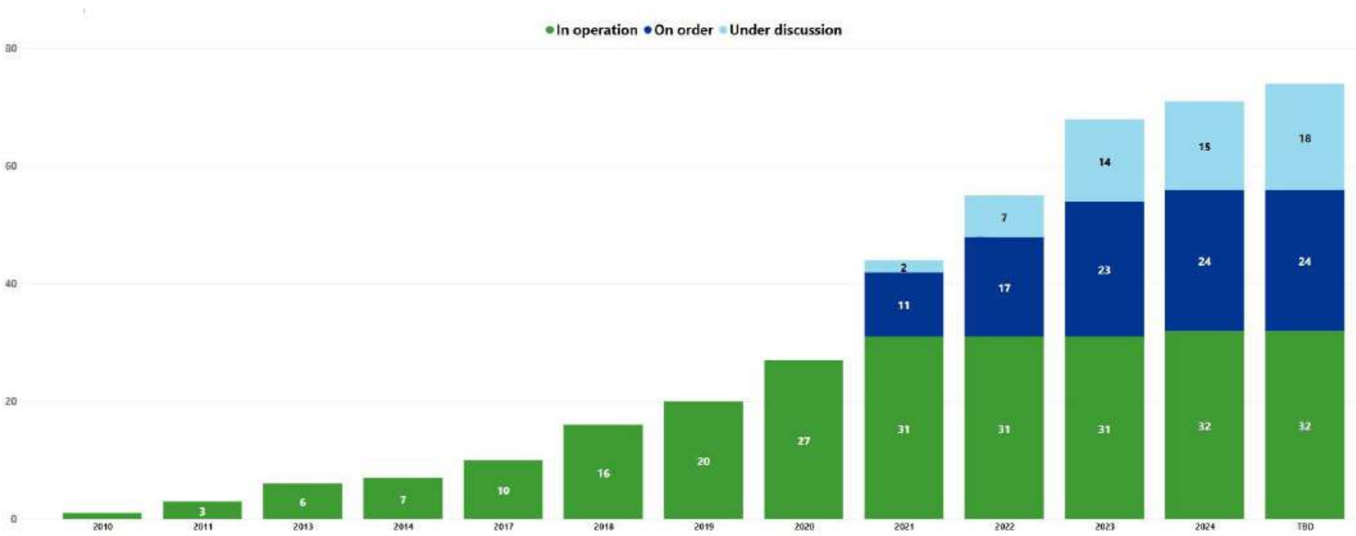


FIGURE 31

LNG bunker vessels in operation, on order and under discussion



3.7.3 Supplier

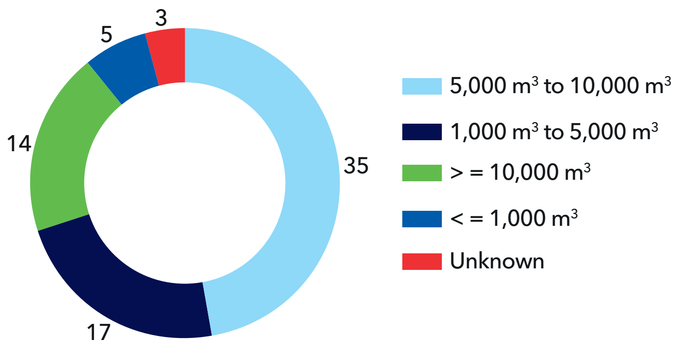
In response to the growing fleet of vessels using LNG as fuel, the LNG bunker fleet is also increasing to serve such ships all around the world. Figure 34 gives an overview of bunker vessels in service and an outlook on potential newbuildings.

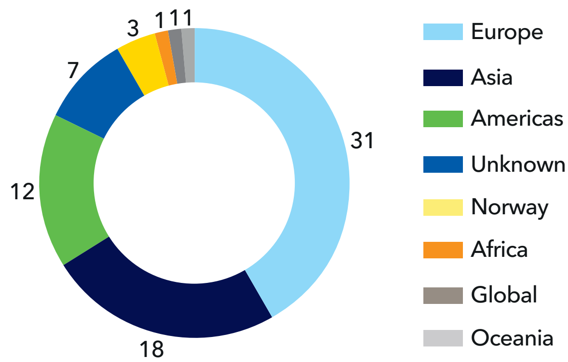
Bunker vessels by tank capacity and area of operation

Figure 35 gives an overview of bunker vessels with different tank capacities, and the number of vessels operating in different areas. Asia and Europe are the main areas of operation. The fleet of LNG bunker vessels is growing rapidly, and these vessels cover most major shipping hubs today. Further developments are expected in the next few years, quickly bridging the gap between supply and demand. Approximately half of the LNG bunker vessels have a capacity of 5,000–10,000 m^3, while the rest are smaller.

FIGURE 32

Bunker vessels by tank capacity and area of operation





3.7.4 Receiving containership

The IGF Code covers equipment required for bunkering operations. The IGF Code covers the requirements for the bunker station, considering the equipment up to the presentation flange. Transfer equipment such as the transfer hose is not covered. The transfer equipment is usually provided by the bunkering facilities.

Depending on port and terminal regulations, during the LNG bunkering process restrictions are imposed on operations of the receiving vessel. In general, the position of bunker stations or bunker ships determine the cargo operations that are possible during the bunkering process. The implications of simultaneous operations are normally evaluated within a risk assessment.

The main objective of this risk assessment is to verify the safe operation of the LNG bunkering system by a systematic identification of any hazards having the potential to cause harm. This is followed by a review to determine whether adequate safety measures exist, or if additional measures are required to mitigate the risk. The scope of the risk assessment covers all safety hazards related to all operations running in parallel to the LNG bunkering process either on land, on water or on the vessels.

At least the following operations will be considered for the simultaneous operations (SIMOPS):

- Loading and unloading of cargo, provisions, and other goods
- Activities on the terminal adjacent to the LNG bunkering operations
- Maintenance and repair / hot works (on board and on shore)
- Parallel oil fuel / lubrication oil bunkering
- Embarking / disembarking of passengers

3.7.5 Bunkering operations

The bunkering operations are normally divided into three stages:

- Pre-bunkering
- Bunkering
- Post-bunkering

The bunkering operation should be performed as per checklists in the LNG bunker management plan to safely complete the bunkering operation.

Pre-bunkering

The pre-bunkering phase normally starts with communication between supply facility and receiving vessel. The risk assessment, compatibility assessment, emergency response plan and training are performed in the pre-bunkering phase. The LNG bunker management plan is established during the pre-bunkering phase

Bunkering

The bunkering phase begins when the supply facility is connected to the receiving ship. The process includes the opening of bunker valves, the initial cool-down, transfer at maximum rate after cool-down, and topping up the tank at a low transfer rate.

Post-bunkering

The post-bunkering phase starts with the shutting down of the bunkering valves. After the shutdown of valves, the draining, purging and inerting sequence is performed before disconnecting the supplying facility and the receiving ship. The post-bunkering documentation is completed and the bunker delivery note (BDN) is issued.

The whole bunkering process has to be documented via bunkering checklists. The IAPH (International Associ-

ation of Ports and Harbors) World Ports Climate Initiative (WPCI) LNG working group has developed harmonized LNG bunkering checklists for different methods of LNG bunkering: ship-to-ship, shore-to-ship and truck-to-ship. These checklists reflect extra requirements of ports with regard to LNG bunkering operations in or near their port environment. The bunkering checklists ensure high safety standards of bunkering operations.

The IAPH checklists are highly relevant references in establishing a quality structure, defining a procedural framework that can be used by all stakeholders involved in the LNG bunkering process.

3.7.6 Risk assessment

Some ports require a quantitative risk analysis (QRA) for bunkering operations in their facilities. The purpose of a QRA is to generate numeric values for the risk caused by the installation. Many countries have developed their own methodologies for performing such an analysis, as well as specific criteria to assess acceptability of the calculated risk.

The following steps of a QRA have to be performed:

- Hazard identification
- Consequence analysis
- Frequency analysis
- Risk calculation
- Location Specific Individual Risk
- Societal risk
- Acceptance criteria

A more detailed explanation of the steps listed is given on the following pages.

Hazard identification

The first stage in any risk analysis is to identify the potential accidents that could result in loss of containment and subsequent release of the hazardous substance. All relevant hazards will form a set of failure scenarios. Failure scenarios specify possibilities for how a dangerous substance can be released to the atmosphere (leak, rupture, etc.).

Consequence analysis

For each failure scenario, consequences have to be determined. These can be for flammable products:

- Explosion
- Fireball
- Boiling Liquid Expanding Vapour Explosion (BLEVE)
- Flash fire
- Jet fire
- Pool fire

The particular outcome(s) modelled depend on source terms and release phenomenology. A current understanding of the important mechanisms occurring during and after the release are included in state of-the-art models in the PHAST (Phylogenetic Analysis with Space/Time) models package. All DNV models have been validated against observations during both experiments and real-life incidents. It furthermore utilizes the Unified Dispersion Model (UDM) for the dispersion modelling, as approved by the US Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) for modelling of LNG dispersion and use in LNG siting applications. The software is used by hundreds of companies worldwide, for instance governments in Australia, Hong Kong, Malaysia and the Netherlands.

Frequency analysis
Failure frequencies must be determined for each failure scenario to conduct a probabilistic risk assessment. In Flanders (Belgium), the UK and the Netherlands, authorities provide the set of failure frequencies to be used. In France and Germany, it is the responsibility of the modeller to select a good data set.

Examples of failure frequency databases are:

- UK Hydrocarbon Release Database (HCRD)
- Flanders Handbook Failure Frequencies 2009
- France Handbook Failure Frequencies 2009 (Flemish data set is allowed by French authorities)
- Germany Handbook Failure Frequencies 2009 (Flemish data set is allowed by ISO/TS 18683:2015)
- Netherlands RIVM Reference Manual Bevi Risk Assessments v3.3 (2015)

Risk calculation
This part of the risk analysis consists of a combination of previous parts. Together with the relevant background data (populations, meteorological data, impact criteria, etc.), risks will be calculated for people both on and off site.

Location Specific Individual Risk
The Location Specific Individual Risk (LSIR) is the risk for an individual who is present at a particular location, 24 hours per day and 365 days per year, without wearing protective clothes. The definition of individual risk is the frequency at which an individual may be expected to encounter a given level of harm (resulting in lethality) as a consequence of specific hazard occurrence. It is often considered as the risk of death and is expressed as risk per year. In most countries, an individual risk of 10–6 per year (once in a million years) is taken as the threshold criterion to assess the acceptability of an accident.

Societal risk
Societal risk is defined as the (cumulative) frequency per year that a particular group of people dies in the same period of time as a result of an accident (i.e. loss of containment). Societal risk is represented in an FN curve, which is a log-log graph: the X-axis represents the number of deaths and the Y-axis the cumulative frequency of the accidents, with the number of deaths equal to N or more. Societal risk is a more meaningful visualization of the risk, as it allows to account for the actual population exposed to the effects of accidents.

Acceptance criteria
Acceptance criteria are country-specific maximum values that local authorities place on the calculated risk picture. In Flanders in Belgium for example, criteria for individual and societal risk are prescribed for companies ranked high tier (ie. higher risk) under the Seveso III Directive (2012/18/EU). In France, a matrix is used to assess the acceptability of the installation in terms of consequence and frequency.

7 Rules and Regulations

7.1 IGF Code (International Code of Safety for Ships Using Gases or Other Low-flashpoint Fuels)
The era of gas-fuelled ships and vessels using low-flashpoint fuels started with the first LNG-fuelled vessel, GLUTRA, which came into operation in 2000. The approval of GLUTRA was based on an exemption by the Norwegian Maritime Authority. SOLAS's requirement for fuels to have a flashpoint above 60°C enabled this national exemption to bring the vessel into service.

In 2004, Norway proposed the development of an international code for gas-fuelled ships at the IMO. In response to this proposal and the growing market for LNG-fuelled vessels, interim guidelines on safety for natural gas-fuelled engine installations in ships were introduced and adopted on 1 June 2009 as an intermediate step. After 2009, the IMO proceeded to develop the IGF Code, which it adopted in 2015 at its 95th MSC Session and which came into force on 1 January 2017.

The purpose of the IGF Code is to provide an international standard for ships operating with gas or low-flashpoint liquids as fuel; vessels other than those covered by the International Code of the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code). The IGF Code provides mandatory requirements for the arrangement and installation of machinery, equipment and systems for vessels operating with gas or low-flashpoint liquids as fuel. The IGF Code was developed using goal-based standards and functional requirements in order to form the basis for the design, construction and operation of such vessels.

Application of IGF Code

- Ships for which the building contract was placed on or after 1 January 2017
- Ships without a building contract, the keels of which were laid, or which were at similar construction stage, on or after 1 July 2017
- Ships which were delivered on or after 1 January 2021
- Ships, irrespective of the date of construction, which converted to using low-flashpoint fuels on or after 1 January 2017

7.2 Crew Training (IGF / STCW Code)
The IGF Code provides the goal and the functional requirements for training of seafarers. Companies shall ensure that seafarers on board ships to which the IGF Code applies have completed training to attain the competencies to perform duties and responsibilities on board ships considering the provisions given in the STCW Code (Seafarers' Training, Certification and Watchkeeping Code), as amended. The STCW Code states mandatory training requirements and is divided into two parts: basic training and advanced training.

Basic training

Basic training is required for seafarers responsible for designated safety duties.

The following competencies are achieved after successful completion of basic training:

- Contribute to the safe operation of the ship
- Precautions to prevent hazards on a ship and to prevent pollution of the environment from the release of fuels found on ships
- Carry out firefighting operations on a ship

Advanced training

Advanced training is required for masters, engineer officers, and all personnel with immediate responsibility for the care and use of fuels and fuel systems on board.

The following competencies are achieved after successful completion of advanced training:

- Familiarization with the physical and chemical properties of fuels on board
- Competence to safely perform and monitor all operations related to fuel on board
- Operate controls of fuel related to propulsion plant and engineering systems and services and safety devices
- Plan and monitor safe bunkering, stowage and securing of the fuel
- Precautions to prevent hazards on a ship and to prevent pollution of the environment from the release of fuels found on ships
- Gain knowledge of the prevention, control, and firefighting and extinguishing systems.

7.3 DNV service documents

7.3.1 General

DNV is an organization with the objective of safeguarding life, property and the environment. DNV carries out classification, certification and other verification services related to ships, facilities, systems, materials and components, and performs research in connection with these functions.

DNV prepares various types of service documents to support the maritime community:

- DNV rules for classification
- DNV class guidelines
- DNV standards
- DNV recommended practices

7.3.2 DNV rules for classification of ships

The DNV rules, standards and guidelines are developed and based on the competence and experience of the engineers' extensive research and development programmes in close cooperation with customers worldwide. The DNV rules for the classification of ships are divided into seven parts:

- Part 1 – General Regulations
- Part 2 – Material and Welding
- Part 3 – Hull
- Part 4 – Systems and Components
- Part 5 – Ship Types
- Part 6 – Additional Class Notations
- Part 7 – Fleet in Service

The requirements for ships operating on gas or low-flashpoint liquids as fuel are covered by "Part 6 – Additional Class Notations". The following three sections are related to the use of low-flashpoint fuels:

- Section 5 – Gas-fuelled ship installations – Gas Fuelled LNG
- Section 6 – Low-flashpoint liquid-fuelled engines – LFL Fuelled
- Section 8 – Gas-ready ships – Gas Ready

7.3.3 Class notations

Gas Fuelled LNG

The additional Gas Fuelled LNG class notation provides criteria for the safe and environmentally friendly arrangement and installation of machinery for propulsion and auxiliary purposes, using natural gas as fuel.

This notation includes requirements for the ship's gas fuel system, covering all aspects of the installation – from the ship's gas fuel bunkering connection up to and including the gas consumers. This section has requirements for the arrangement and location of gas fuel tanks and all spaces with fuel gas piping and installations, including requirements for the entrances to such spaces. Hazardous areas and spaces, due to the fuel gas installations, are defined. Requirements for control, monitoring and safety systems for the fuel gas installations are included.

The Gas Fuelled LNG class notation applies to installations using gas as fuel in ships. This includes internal combustion engines, boilers, and gas turbines. The installations may run on gas only or be dual-fuel installations. Gas may be stored in a gaseous or liquefied state. The rules are applicable for installations where natural gas is used as fuel. If other gases are used as fuel, then special consideration will need to be taken.

LFL Fuelled (low-flashpoint fuelled engines)

The additional LFL Fuelled class notation provides criteria for the arrangement and installation of machinery for propulsion and auxiliary purposes, using low-flashpoint liquids (LFLs) as fuel, which will have an equivalent level of integrity in terms of safety and availability as that which can be achieved with new and comparable conventional oil-fuelled main and auxiliary machinery.

This notation is applicable for installations where methyl alcohol or ethyl alcohol is used as fuel. Other liquid fuels with low flashpoints may be accepted for use after special consideration. The use of low-flashpoint liquid fuel is not currently covered by international conventions, and such installations will need additional acceptance by flag authorities.

Gas Ready

The additional Gas Ready class notation has supplementary levels and corresponding requirements. The minimum mandatory levels include verification of compliance with Gas Fuelled LNG class rules for a future LNG-fuelled ship design, and the main engine(s) installed can be converted to gas or dual-fuel operation (or are of dual-fuel type from the newbuild stage).

This notation provides the basis for compliance with the rules in force at the time of contract for the construction of the newbuilding. The rules in force at the time of a later ship conversion to LNG fuel shall be complied with regardless of the Gas Ready notation. The Gas Ready class notation does not include survey requirements for follow-up of the ship when in operation. At the time of the conversion, a survey and evaluation of the condition of the equipment or systems installed from the newbuild stage will be performed. The rules are applicable for installations where natural gas, stored as LNG, is intended to be used as fuel. If the rules are applied to designs with other gas fuels, special considerations will have to be made.

7.3.4 DNV recommended practices

DNVGL-RP-G105 Development and operation of liquified natural gas bunkering facilities

The objective of this recommended practice (RP) is to establish the guidelines required to protect the safety of people, property and the environment when developing and operating LNG bunkering facilities. Furthermore, this document is intended to increase the overall understanding of the risks associated with LNG bunkering and demonstrate how to best manage the associated risks. DNVGL-RP-G105 provides guidance to the industry on development, organizational, technical, functional and operational issues in order to ensure global compatibility and secure a high level of safety, integrity and reliability for LNG bunkering facilities, throughout its life cycle. The functional requirements provided in this RP are in line with, but elaborate on, "ISO/TS 18683 Guideline for systems and installations for supply of LNG as fuel to ships". LNG bunkering facilities in the context of this document is the ship/facility interface where LNG bunkering is intended to take place or is taking place. The term may be used for any of the bunkering scenarios terminal-to-ship, truck-to-ship or ship-to-ship.

The main topics covered by this RP are as follows:

- Development of LNG bunkering facilities
- Risk assessments for LNG bunkering facilities
- Safety management system (SMS) requirements
- Operation of LNG bunkering facilities
- Determination of the quantity and properties of the supplied LNG

7.3.5 Tank guideline

DNVGL-CG-055 Gas-fuelled containerships with independent Type A and Type B prismatic tanks

This guideline provides supplementary technical and procedural requirements and general information on the rules. The following aspects are covered:

- Material selection for the tank and supporting structure
- Material selection of the ship hull structures adjacent to the tank
- Finite element assessment of the ship structure containing the gas fuel tanks
- Strength of the gas fuel tank structure:
  - Yield strength
  - Fatigue strength
  - Crack propagation
- Strength of tank supporting structure
- Vibration analysis

8 Terminology

AER	Annual Efficiency Ratio
ATEX	EU directive for equipment intended for use in explosive atmospheres
BDN	Bunker delivery note
BEVI	Decree on safety of devices (Netherlands)
BLEVE	Boiling Liquid Expanding Vapour Explosion
BOG	Boil-off gas
CAPEX	Capital expenditure
CG	Class Guideline (document type published by DNV)
CH_4	Methane
CII	Carbon Intensity Index
CNG	Compressed natural gas
CO_2	Carbon Dioxide
CV	Container vessel
DDC	Dry Disconnect Coupling
DNV	DNV AS, headquartered in Norway
ECA	Emission Control Area
EEDI	Energy Efficiency Design Index
EEXI	Energy Efficiency Existing ship Index
EGR	Exhaust gas recirculation
ERC	Emergency Release Coupling
ESD	Emergency Shut Down
FEA	Finite element analysis
FLS	Fatigue Limit State
FPR	Fuel preparation room
GCU	Gas combustion unit
GHG	Greenhouse gas
GVU	Gas valve unit
GWP	Global Warming Potential
HCRD	Hydrocarbon Release Database (UK)
HFO	Heavy Fuel Oil
HP	High-pressure
IACS	International Association of Classification Societies
IAPH	International Association of Ports and Harbors
IEC	International Electrotechnical Commission
IFO	Intermediate Fuel Oils
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
LFL	Lower flammability limit
LNG	Liquified natural gas
LP	Low-pressure
LPG	Liquified petroleum gas
LSFO	Low Sulphur Fuel Oil
MARPOL	The International Convention for the Prevention of Pollution from Ships
MEPC	Marine Environment Protection Committee
MGO	Marine Gas Oil
NB	Newbuilding
NG	Natural gas
Ni	Nickel
NOX	Nitrogen oxides
OEM	Original Equipment Manufacturer
OPEX	Operating expenditure
PBU	Pressure Build-up Unit
PERC	Powered Emergency Release Coupling
PHAST	Phylogenetic Analysis with Space/Time
PHMSA	Pipeline and Hazardous Materials Safety Administration
PM	Particulate matter
PTO	Power take-off
QRA	Quantitative risk analysis
SCR	Selective Catalytic Reactor
SEEMP	Ship Energy Efficiency Management Plan
SGMF	Society for Gas as a Marine Fuel
SIMOPS	Simultaneous operations
SOLAS	Safety of Life At Sea
SOX	Sulphur oxides
STCW	International Convention on Standards of Training, Certification and Watchkeeping
TCS	Tank connection space
TEU	Twenty-foot Equivalent Unit
TTF	Title transfer facility
UDM	Unified Dispersion Model
ULCV	Ultra large container vessel
ULS	Ultimate Limit State
ULSFO	Ultra Low Sulphur Fuel Oil
UNFCC	United Nations Framework Convention on Climate Change
VLSFO	Very Low Sulphur Fuel Oil
VOC	Volatile Organic Components
WPCI	World Ports Climate Initiative

ABOUT DNV

We are the independent expert in risk management and quality assurance. Driven by our purpose, to safeguard life, property and the environment, we empower our customers and their stakeholders with facts and reliable insights so that critical decisions can be made with confidence. As a trusted voice for many of the world's most successful organizations, we use our knowledge to advance safety and performance, set industry benchmarks, and inspire and invent solutions to tackle global transformations.

Regional Maritime Offices

Americas
1400 Ravello Drive
Katy, TX 77449
USA
Phone +1 281 3961000
houston.maritime@dnv.com

Greater China
1591 Hong Qiao Road
House No. 9
200336 Shanghai, China
Phone +86 21 32799000
marketing.rgc@dnv.com

North Europe
Johan Berentsens vei 109-111
Postbox 7400
5020 Bergen, Norway
Phone +47 55943600
bergen.maritime@dnv.com

South East Europe,
Middle East & Africa
5, Aitolikou Street
18545 Piraeus, Greece
Phone +30 210 4100200
piraeus@dnv.com

West Europe
Brooktorkai 18
20457 Hamburg
Germany
Phone +49 40 361495609
region.west-europe@dnv.com

Korea & Japan
7th/8th Floor, Haeundae I-Park C1 Unit,
38, Marine city 2-ro, Haeundae-Gu
48120 Busan, Republic of Korea
Phone +82 51 6107700
busan.maritime.region@dnv.com

South East Asia, Pacific & &India
16 Science Park Drive
118227 Singapore
Singapore
Phone +65 65 083750
singapore.maritime.fis@dnv.com

DNV
Brooktorkai 18
20457 Hamburg, Germany
Phone +49 40 361400
www.dnv.com

DNV AS
NO-1322 HØvik,
Norway
Phone +47 675700
www.dnv.com