CHAPTER 2

Economics of Gas Transportation by Pipeline and LNG

Gergely Molnar

The relatively low energy density of natural gas on a volumetric basis—almost 1000 times lower compared to crude oil—makes it one of the most challenging and expensive primary fuels to transport from the wellhead to the burner tip of end-consumers. Internationally traded natural gas is typically transported either in gaseous form via long-distance pipeline systems or in the form of liquefied natural gas on ships (LNG carriers).

The transport segment alone can account for over 50% of the costs occurring through the value chain of internationally traded natural gas. As a consequence, natural gas remained for a long time a local commodity, consumed relatively close to its production centres. Inter-regional natural gas trade emerged gradually with the start-up of the first commercial LNG export facilities and the construction of long-distance pipelines through the 1960s and 1970s.

The share of inter-regionally traded gas in total consumption rose gradually from below 5% in 1975 to 15% in the early 2000s and reached 21% in 2018. In comparison, around half of crude oil produced has been traded in 2018.

Whilst pipelines have dominated international gas trade for a long time, LNG exports more than tripled since the beginning of the century and accounted for just over half of international gas trade in 2018. This has been driven by a particularly strong gas demand growth in the markets of the Asia Pacific region, which have no or limited alternative supply options to LNG (such as Japan and Korea) (Fig. 2.1).

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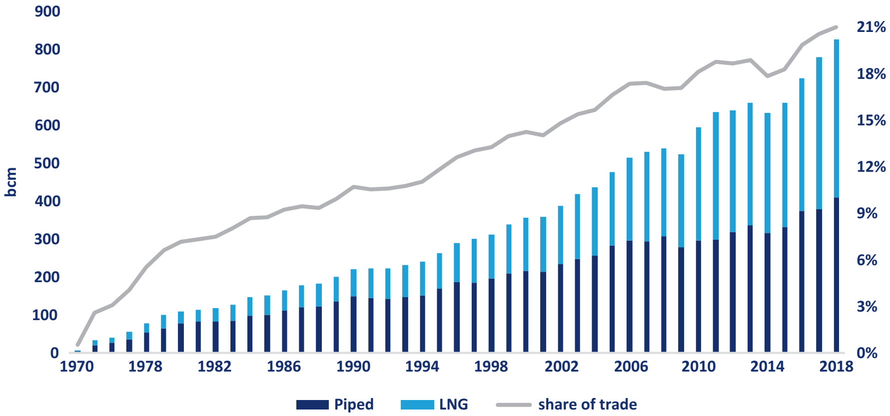

Fig. 2.1 International trade of natural gas (1970–2018). Total LNG exports and intercontinental pipeline trade, including Norway to the rest of Europe. (Source: International Energy Agency)

Besides pipelines and LNG, a number of alternative technologies and methods have been developed to monetize and transport natural gas; however, their utilization remains marginal and is typically serving local markets (see Box 2.1).

This chapter will focus of the economics of large infrastructure projects underpinning the international trade of natural gas, that is, long-distance pipelines and large-scale LNG.

Box 2.1 Alternative Gas-to-Market Transport Options

A number of methods have been developed to transport and monetize the energy value of methane.

This includes the transportation of compressed natural gas (**CNG**) containers and **small-scale LNG** ISO tanks via trucks and rail. These **"virtual pipelines"** can play a crucial role in meeting local natural gas demand in emerging markets with strong consumption growth and a still developing pipeline network. In China, LNG delivered via trucks accounted for over 10% of the national gas consumption in 2017.

Natural gas can also be **transformed into other forms of energy carriers** (gas-to-power, gas-to-liquids, gas-to-solids) close to the upstream source and transported as such to the end-consumers.

Gas-to-wire attracted considerable attention in emerging markets where natural gas is primarily used to meet rapidly growing electricity needs. The largest gas-to-wire project is currently developed in Brazil in the Açu port of Rio de Janeiro. The project consists of a 1.3GW combined cycle plant integrated to an LNG regasification terminal, a transmission line and a substation connected to the national grid.

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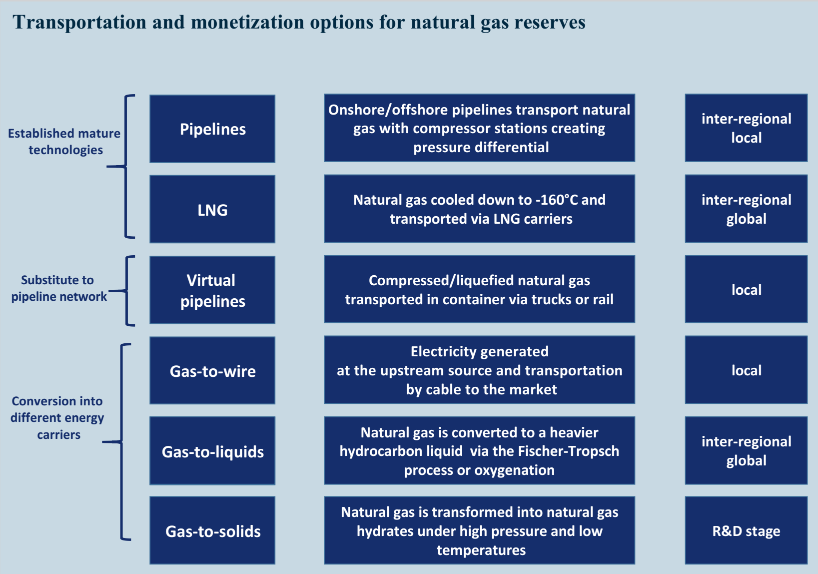
Gas-to-liquids (GTL) is a refinery process transforming methane into a heavier hydrocarbon liquid (such as diesel or gasoline) most commonly using the Fischer-Tropsch (F-T) synthesis. First, methane is converted to syngas (a mixture of hydrogen, carbon dioxide and carbon monoxide). After impurities (such as sulphur, water and carbon dioxide) are removed, syngas is reacted in the presence of an iron catalyst in an environment of high pressure (40 atmospheres) and extremely high temperatures ranging from 260 to 450 °C. Whilst GTL is a technologically proven process, its commercial viability at a large still needs to be proven. There are currently five large GTL projects operating globally, with a total production capacity of close to 250,000 barrels per day (equating to ~0.2% of global liquids production).

Gas-to-solids (GTS) technology processes consist of transforming methane into a solid form called natural gas hydrates (NGH) by mixing natural gas with water at 80–100 bar and 2–10 °C. It is created when certain small molecules, particularly methane ethane and propane, stabilize the hydrogen bonds within water to form a three-dimensional structure able to trap the methane molecule. GTS technologies are still in the state of research and development and no project reached the state of commercial phase.



Transportation and monetization options for natural gas reserves

1 Long-Distance Pipelines

Pipelines have been the natural choice to transport methane in its gaseous form. First historical records of practical usage of natural gas date back to 500 BCE in China, where natural gas was transported via "bamboo pipes" and used to boil ocean water to separate salt and create drinkable water (effectively desalination).

Modern pipeline systems—most often built from steel—can transport natural gas through several thousands of kilometres from the wellhead to the burner tip of end-consumers. Four major types of pipelines can be distinguished along the transportation route:

- Gathering (or upstream) pipelines are typically low-pressure, small-diameter pipelines (4–12 inches) that transport raw natural gas from the wellhead to the processing plan.
- Transmission pipelines are large-diameter pipelines (16–56 inches) operating under high pressure (15–120 bar) and transporting cleaned, dry natural gas through long distances from the processing plant either directly to large end-consumers (such as power plants or industrial sites) or to the city gate where it connects to the distribution system.
- Distribution pipelines are small- to medium-size pipelines (2–28 inches) carrying odorized natural gas under a relatively low pressure (up to 14 bars) from the city gate to its connection with service lines.
- Service lines are small-diameter pipelines (below 2 inches), operating under very low pressure (around 0.5 bars) and delivering natural gas directly to the end users (such as commercial entities and residential consumers).

From an operational point of view, in all cases natural gas flows in the pipelines from one point to another due to the pressure differential existing between those two points. Pressure differential is created and maintained by compressor stations located along the pipeline system (typically located at every 100–200 km of the transmission pipelines).

Compressor stations (containing one or more compressor units) squeeze the incoming natural gas to push it out a higher pressure, allowing pressure to be increased within the pipeline, which is effectively needed to keep natural gas flowing. With the travelled distance increasing, the gas pressure falls due to friction and thus requires further compression. Friction loss (or major loss) results by the movement of molecules against each other and the wall of the pipe.

Other non-linear parts of a pipeline system include metering stations, which measure the flow of gas along the pipeline and enable the operator of the pipeline system to monitor natural gas flow along the pipeline. Operational information (such as flow rate, pressure, temperature and operational quality) from the compressor and metering stations is transmitted to a centralized control station via Supervisory Control and Data Acquisition (SCADA) systems. This allows a permanent monitoring of the pipeline system, ensuring its stable and safe functioning.

This chapter will focus on the large-diameter, long-distance transmission pipelines which enable international trade of natural gas by transiting methane through several countries and borders. The first part of the chapter will provide an overview of the underlying economics of pipeline projects (including CAPEX and OPEX), whilst the second part will focus on the commercial aspects (including contract structuring and tariff regimes).

1.1 Economics of Pipeline Projects

Natural gas pipeline projects are capital intensive by nature. High upfront investment costs typically account for over 90% of total costs occurring through the lifespan of a gas pipeline (~40 years), whilst operating expenses (e.g. fuel costs associated with gas compression, maintenance and repairs, staff, etc.) usually account for up to 5–10% of total costs. Consequently, the initial design of the project and the optimization of capital expenditures needs careful consideration as it has a disproportionate impact on the overall economics of the project.

1.1.1 CAPEX

The investment cost of a natural gas pipeline is ultimately determined by its (1) length, (2) capacity (diameter × operating pressure) and (3) unit investment costs.

The linear part of a pipeline system—commonly called the "line pipe"—accounts for the majority of the CAPEX, whilst the share of the investments into compressor and metering stations typically accounts between 15 and 30%.

Unit investment costs of international pipelines can vary in a wide range from $30k to over $200,000/km/inch, depending on a number of factors, including external conditions such as terrain and climatological context, labour and material costs, project management as well as the stringency of the regulatory framework(s) (primarily environmental and safety standards). The unit cost of compressor stations is typically in the range of $2–$4 million per MW of installed power.

Figure 2.2 shows the breakdown of the average unit investment costs for the line pipe and the compressor stations, respectively.

Unit investment costs can be broken down into four main categories:

- Material costs:
  - for the linear part of the pipeline system, it includes pipe sections (made usually from high carbon steel and fabricated in steel rolling mills), pipe coating and cathodic protection. It typically accounts for around one-third of total investments costs and is highly dependent of the evolution of steel prices;

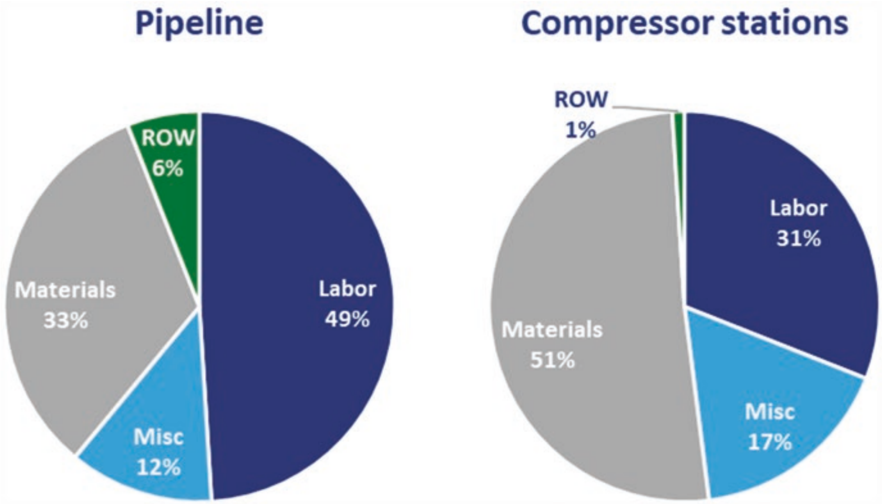


Fig. 2.2 Breakdown of average unit investment costs into pipelines and compressor stations. (Source: based on ACER (2015))

- for compressor stations, material costs are the most important cost component, accounting for about half of total investment. This includes the pre-fabricated modular functional units of a compressor station (such as gas scrubbing and liquid removal, compressor and driver units, gas coolers, pipes and valves).

- Labour costs:
  - are typically the most important cost component of the line pipe, accounting for over 40% of the unit investment cost. This includes the salaries and wages related to the preparation of the terrain (clearing, grading and trenching) and the construction of the pipeline (stringing, welding, coating pipeline segments, depositing the pipeline and backfilling);
  - the construction of compressor stations includes site preparation, construction of the compressor building(s) and assembling compressor units. It is a somewhat less labour-intensive process compared to pipe laying, with labour costs accounting to around one-quarter of unit investment costs of compressor stations.

- Miscellaneous costs generally cover surveying, engineering, supervision, contingencies, telecommunications equipment, administration and overheads, freight, regulatory filing fees as well as taxes. They typically account for over 10% of total unit investment costs in the case of both the pipelines and compressor stations.
- Right-of-way (ROW) costs include obtaining rights-of-way and allowing for damages.

It is important to highlight that the breakdown of average unit investment costs presented above is purely indicative.

Each pipeline system is unique and hence the cost breakdown will vary by pipeline. For instance, pipes built in more challenging external environments (such as mountainous terrain, rocky soil, wetlands or ultra-deep offshore) will usually have a higher proportion of costs associated with labour and logistics and will depend less on material expenditures. Pipelines crossing high population density areas have in general higher miscellaneous and right-of-way costs and need to abide to more stringent safety standards. Construction of offshore pipeline systems requires both specific line design (wall thickness up to 2 inches to support water pressure, insulation against low-temperature environment and ballasting to provide stability) and a specific set of logistics (including pipelaying vessels with day rates often at several $100k/day), which can increase significantly investment unit costs.

Figure 2.3 provides indicative additions to pipeline construction costs, depending on their respective external environment.

Worth to note that international pipelines—crossing several borders and countries—have to comply with various jurisdictions and regulatory frameworks—which can substantially increase their miscellaneous costs related to administration and regulatory filing fees.

In addition to the cost components related to technical CAPEX, the financial structure and the cost of capital can alter significantly the economics and the profitability of pipeline projects. External financing can account for up to 70% of financing in major international gas pipeline projects. Investors/lenders typically look for LIBOR +3–4% for pipeline investments, depending on the location, the project promoters and their risk appetite. Based on those assumptions, financial expenditures (FIEX) can add 10–15% to the initial technical CAPEX.

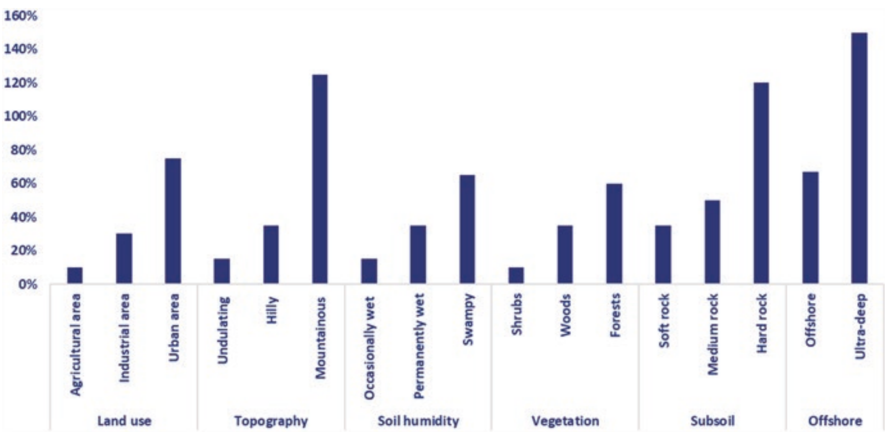


Fig. 2.3 Indicative additions to pipeline construction costs, per difficulty factor. (Sources: based on CEER (2019), Yamasaki (1980) and Author's estimates)

1.1.1.1 Economies of Scale

Natural gas transportation via pipelines naturally results in economies of scale. Whilst the throughput capacity of a pipeline is increasing following the $\pi r^2 L$ formula—where r stands for the radius (half of the diameter) and L for the length of the pipeline—the material costs required for the construction of the line pipe is increasing in line with the $2\pi rL$ formula. Consequently, unit transport costs for the same level of utilization are usually lower for pipelines with larger diameters and built in similar external environment.

Moreover, some of the costs associated with pipeline construction are fixed (design, permits) or increase insignificantly compared to a higher design and working capacity of the pipeline system.

Further, it should be noted that several smaller compressor units will have a higher cost per MW compared to a larger unit with same compressing power due to economies of scale (Fig. 2.4).

1.1.2 OPEX

Operating expenses represent a fraction of the overall costs occurring through the lifespan of a pipeline project, typically accounting for 5–10% of the total costs of natural gas transportation.

Figure 2.5 provides a purely illustrative example of the breakdown of operating expenses, based on the financial reporting of a major European gas transmission company.

Operating costs of a pipeline system can be broken down into four main categories:

- Fuel costs: primarily associated with the energy requirements of compressor stations running either on natural gas or on electricity (see Box 2.2). "Fuel gas" is either provided by the shippers themselves as "fuel gas in kind" or procured by the operator of the transmission system operator via

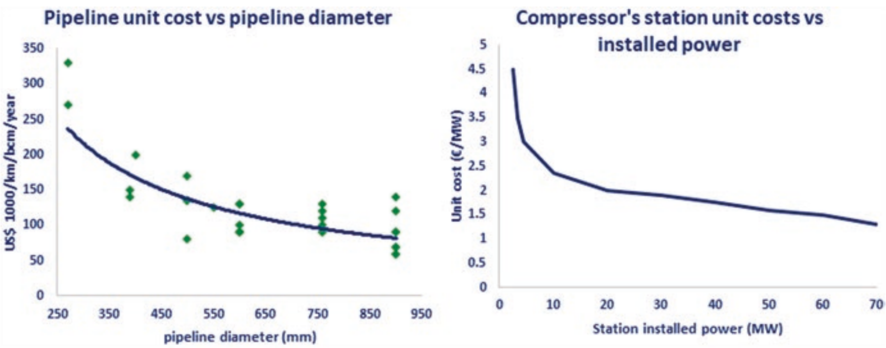


Fig. 2.4 Economies of scale in natural gas pipeline systems. Green dots indicating individual gas pipeline projects. (Sources: International Energy Agency (1994) and CEER (2019))

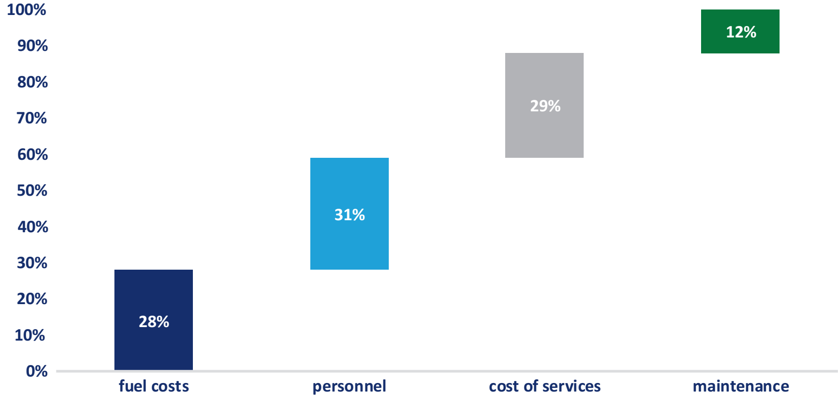


Fig. 2.5 OPEX of gas transmission company

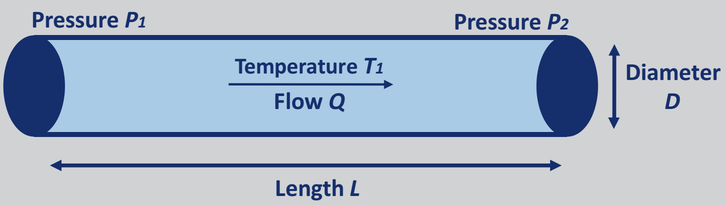
Box 2.2 Compressor Stations

Compressor stations are at the heart of natural gas pipeline systems. The necessary operational pressure needed to transport ("make flow") natural gas is ensured at the starting point of the pipeline system by a **head compressor**.

Natural gas flow in the pipeline can be described with the **general flow equation**:

$$Q = \frac{7.574 \times 10^{-4}}{\sqrt{f}} \times \frac{Ts}{Ps} \times \sqrt{\frac{\left(P_1^2 - P_2^2\right) D^5}{SLZT}}$$

where Q stands for the gas flow rate (m^3/h), f is a general friction factor for gas (determined from the Moody Diagram), T is the temperature in Kelvin, Ps is the standard pressure (in bar), P1 is the inlet pressure, P2 is the outlet pressure, D is the diameter of the pipeline in mm, S is the relative density (air/gas), L is the length of the pipeline (in m) and Z is the compressibility factor of gas (Nasr, Connor 2014).



Steady gas flow in a pipeline

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The initial **pressure drops** with the travelled distance due to the friction occurring between the molecules of methane and against the wall of the pipe. Pressure drop can be described from the **Darcy-Weisbach equation** as the following (Menon 2011):

$$H_f = f\frac{L}{D} \times \frac{V^2}{2g}$$

where H_f stands for the head loss due to friction, f is a general friction factor for gas, L is the length of the pipeline (m), D is the internal diameter of the pipeline (in mm), V is the velocity (in m/s) and g stands for the gravitational acceleration constant (9.81 m/s^2).

The loss of pressure requires the installation of so-called **intermediary compressor stations**, typically located at every 100–200 kms of the pipeline system.

The required **compression power** is given by the following equation (Menon 2011):

$$Power\left(kW\right) = 4.0639\left(\frac{y}{y-1}\right)QT_1\left(\frac{Z_1+Z_2}{2}\right)\left(\frac{1}{n_a}\right)\left[\left(\frac{P_2}{P_1}\right)^{\frac{y-1}{y}}-1\right]$$

where y stands for ratio of heat of gas (1.4), Q for gas flow rate (million m^3/d), T for temperature (in Kelvin), Z_1 compressibility of gas at suction conditions (when entering the compressor station), Z_2 compressibility of gas at discharge conditions (when leaving the compressor station), P_1 suction pressure of gas (kPa), P_2 discharge pressure of gas (kPa) and n_a is the compressor's isentropic efficiency (typically between 0.75 and 0.85).

A compressor station typically consists of the following facilities:

- **Inlet scrubber**: to clean up the entering natural gas stream from any impurities that may have formed during its voyage in the pipeline;
- One or several **compressor units**: each of which includes drivers and compressors;
- **Gas cooler**: necessary to reduce the temperature of the gas after compression to a level which is tolerable for the pipelines;
- **Outlet scrubber**: to clean the exiting natural gas stream from impurities which might have formed during compression;
- **Control systems**: station control monitors inflow and outflow of natural gas and unit control systems monitor the compression process. All data and information are reported to the central control station via SCADA.

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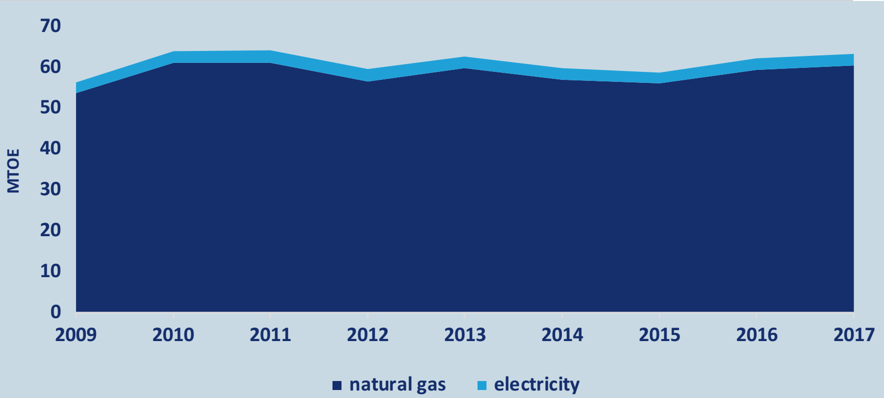
Depending on the network configuration and throughput capacity of the pipeline system, aggregate capacity of compressor stations can range from less than 10 MW to several hundreds of MW. The world's largest compressor station is located in Portovaya, Russia, with an aggregate capacity of 366 MW.

Two main types of compressors can be distinguished:

- **Reciprocating compressors**: usually driven by either electric motors or gas engines with a reciprocating moving piston compressing natural gas;
- **Centrifugal compressors** are driven by gas turbines or electric motors, increasing the pressure of natural gas with mechanical rotating vanes.

Compressor stations are using either natural gas (typically taken from the transmission system) or electricity. Data from the International Energy Agency indicate that natural gas accounts for ~95% of energy consumed by natural gas pipelines.



Energy consumption of pipelines per fuel (2009–2017). (Source: International Energy Agency)

Whilst the fuel efficiency of pipeline systems varies depending on their design and external environment, typically, fuel gas usage equates to less than 0.5% of the volume transported per 100 km, that is, less than 5000 cubic metre per 1 million cubic metre transported over 100 km. Pipelines with larger diameters tend to have a lower fuel requirement for the transportation of the same quantity of gas due to lower friction loss.

a competitive tendering process. In the case of vertically integrated companies, where the shipper and the transmission system operator are not separated, fuel costs are part of the company's internal costs.

- Personnel costs include salaries and wages of the employees of the company operating the transmission system, as well as social security contributions and other employee benefits.

- Services costs include all expenses related to services required to manage the pipeline system (such as information technology systems, telecommunication services) and the operating company itself (technical, legal, administrative, personnel-related services) as well as miscellaneous expenses (such as insurance, marketing and consulting).
- Maintenance costs are associated with the inspection, maintenance and repairs of the pipeline system in order to maintain its operational status without necessarily expanding its lifespan.

The breakdown of OPEX cost components can show a high degree of variation depending on technical features and general state of the pipeline system. For instance, an ageing pipeline system running through a challenging environment will naturally have higher maintenance and repair costs. Fuel costs will vary depending on the fuel procurement process, that is, inhouse, "gas in kind" or open tendering process.

1.1.3 Optimal Pipeline Design

Each project developer strives for the most cost-efficient pipeline system design, in terms of both CAPEX and OPEX.

Considering that length and terrain are external and fixed factors, the following considerations are usually taken into account for pipeline system design:

- Quantities to be transported: based on actual market demand and/or expectations, including seasonal variations and modelled peak;
- Internal pipeline diameter: larger diameters reduce pressure drop and hence lower the need for compression power, but necessarily increase the initial CAPEX of the project;
- MAOP (maximum allowable operational pressure): the highest pressure allowed at any point along a pipeline. It is typically between 80 and 100 bar for large transmission systems. There is generally a trade-off between MAOP and pipeline wall thickness. Generally, pipelines running through densely populated areas have a lower MAOP;
- Flow velocity: shall be kept below maximum allowable velocity to prevent pipe erosion (a maximum velocity of ~72 km/h is typically recommended);
- Compressor stations' capacity and spacing, which ultimately influence their fuel consumption (variable OPEX) and performance: a large pressure drop between stations results in a large compression ratio, typically leading to poor compressor station performance.

The techno-economic optimization of the pipeline system design should be based on the hydraulic calculation of the pipeline and followed by a series of NPV calculations (taking into consideration the cost of capital). Typically a software computer program is used for modelling purposes and cost computations before determining the optimal configuration of the pipeline

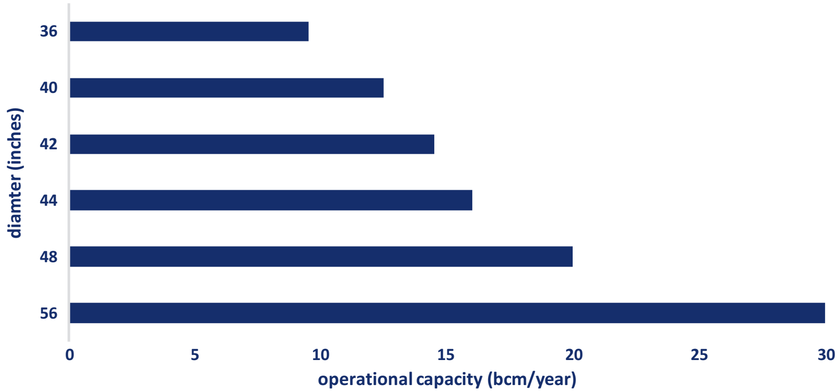


Fig. 2.6 Rule of thumb for optimal pipeline capacity in relation to internal pipe diameter. (Source: based on Brauer (2016))

system in relation to its throughput, diameter and operating pressure. Figure 2.6 provides typical throughput capacities associated with respective internal pipe diameters and assuming an operational pressure of 100 bar.

1.2 Commercial Implications: Contract Design and Tariff Structuring

Natural gas pipeline systems have high upfront investment costs, which become sunk as soon as the pipeline is laid down—due to the inflexible and durable nature of this infrastructure.

Consequently, project developers seek long-term and firm commitments from customers, in order to (1) mitigate investment risk (and hence lower the cost of capital) and (2) ensure a stable revenue flow to recoup capital investment.

Moreover, pipeline system owners have a strong incentive to maximize the utilization of the infrastructure, as it leads to a shorter payback period on capital and allows for a better optimization of fixed operating costs.

These basic considerations are typically reflected in the design and tariff structure of the Gas Transportation Agreements (GTA) concluded between the transporter (the operator of the pipeline system) and the shipper (the customer of the transporter—typically the owner of the natural gas being transported or an agent acting on its behalf).

In the case of the development of new, large gas pipeline systems, GTAs are usually signed before a final investment decision is taken, as they are seen as crucial to address the "capacity risk" of the pipeline project.

GTAs are often underpinned by Gas Sales Agreements (GSAs), between the seller (whose agent is the shipper) and its client(s) (located on the other end of the prospective pipeline). In these cases, GTAs often mimic the contractual arrangements of GSAs. For a detailed review of GSAs, please refer to Chap. 20 of the Handbook (*The trading and price discovery for natural gas*).

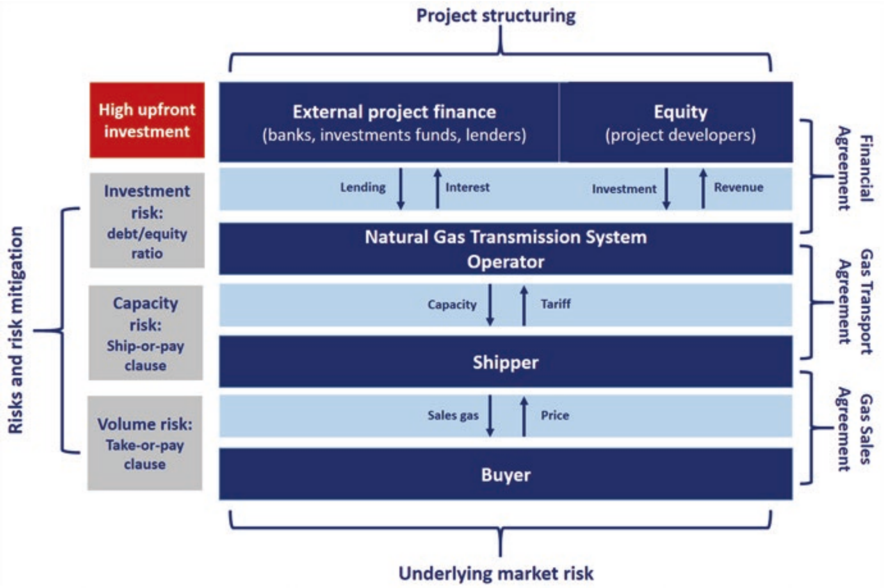


Fig. 2.7 Risk mitigation along the gas value chain. (Source: Author)

Figure 2.7 provides a simplified schematic representation of the interplay between financial arrangements, GTAs and GSAs in mitigating the investment risks associated with natural gas projects.

1.2.1 Characteristics of Gas Transportation Agreements

Under a Gas Transportation Agreement (GTA), the transporter provides a transportation service to the shipper between an input or entry point and one or multiple delivery points, in exchange for a payment made by the shipper and determined by the tariff structure (fixed in the GTA) and the volume transported and/or capacity contracted.

Capacities can be expressed either in volumetric terms (volume/time) or in reference to the energy value of the gas (energy/time).[1]

GTAs underpinning the development of new, large, international gas pipeline systems have typically the following characteristics:

1. Term commitment: GTAs are typically long-term contracts, with a duration of often over 20 years, necessary to recover the initial investment through the revenue from the transportation tariff paid by the shipper(s). The duration of the GTA is commonly aligned with the GSAs of the

[1] In SI units, volumetric capacity would be expressed as mcm/d and energy (thermal) capacity as MWh/d. In USCS, volumetric capacity can be expressed as mcf/d and energy capacity as mmbtu/d.

seller. Term commitments are usually shorter when concluded/renewed in relation to an existing gas transmission system.

2. Tariff commitment: the payments of the shipper for the used and/or reserved capacity will depend on the tariff fixed in the GTA. Tariffs should be non-discriminatory, cost-based and include a reasonable rate of return.
3. Capacity commitment: GTAs typically include a ship-or-pay commitment (often covering the entire firm technical capacity of the pipeline) from the shipper, in order to provide the transporter with a stable revenue stream through the lifespan of the contract. Two main types of GTAs can be distinguished in respect of capacity commitment:

   - Quantity-based: the transporter and shipper agree on the volumes of natural gas to be transported in the pipeline system under the fixed tariff structure. The shipper will typically take a ship-or-pay commitment in relation to the annual quantity (annual ship-or-pay quantity);
   - Capacity-based: the transporter and shipper agree on the capacity the transporter reserves for the shipper in the pipeline system (annual reserved capacity) and for which the shipper is obliged to pay irrespective of the volumes actually being transported. As such, capacity-based transportation agreements inherently have a ship-or-pay component.

In both cases, the shipper shall make a ship-or-pay payment, equating to: (ship-or-pay quantity—unused quantity) × tariff. Make-up provisions (for instance, allowing for a higher capacity usage during the next contract year in order to compensate for the previously unused capacity) might exist, but their occurrence in GTAs compared to GSAs is rare. Worth to mention, in liberalized gas markets the use-it-or-lose-it principle is prevailing: shippers are not allowed to hoard capacity, all unused capacity shall be made available to other, potentially interested shippers via auctions.

1.2.2 Tariff Structures

Alongside the duration of the contract and ship-or-pay commitments, the tariff structure fixed in the GTA is the most important factor underpinning the economic viability of a gas transmission system.

In essence, tariffs shall be structured in way to allow the recovery of the following three components:

- Capital costs related to the initial investment into the gas pipeline system;
- Operating costs occurring during the transportation services provided for the shipper (including fuel gas, personnel, etc.);
- Expected return: the profit element the owner of the transport system is expected to make on its investment.

The different cost elements can appear in a bundled way or separately, including a capacity component (fixed, reflecting the capacity booked) and a commodity charge (variable, reflecting the volumes actually transported). Similarly to capacities, tariffs can be either volume based (payment in relation to volume/time) or energy based (payment in relation to energy/time).

In liberalized gas markets, transport tariffs (1) have to be approved by the regulatory authorities; (2) have to be transparent; (3) should reflect actual costs incurred while including an appropriate return on investments and (4) should be applied in a non-discriminatory manner.

Two main types of tariff structures can be distinguished:

- Distance-based (point-to-point model): the transport tariff is set in relation to the distance between the input and delivery points.

$$C = TDV$$

where C stands for transport cost, T for tariff (€/100 km/1000 cubic metres), D for distance (km) and V for volume (cubic metres).

- Entry-exit system: the total transport costs for the shipper results from the addition of the entry and exit capacity charges it pays when entering and exiting the given transmission network.

$$C = E_n + E_x$$

where C stands for transport cost, E_n for entry fee (€/(m^3/h)/a) and E_x for exit fee (€/(m^3/h)/a).

In an entry-exit system, tariff setting can be based on a uniform approach where tariffs for different network points are set equally (postage stamp) or based on locational differentiation where the tariffs differ for every entry and exit point or zone (locational tariffs).

The tariff formula usually includes an inflation index to protect the investment value of the project (Fig. 2.8).

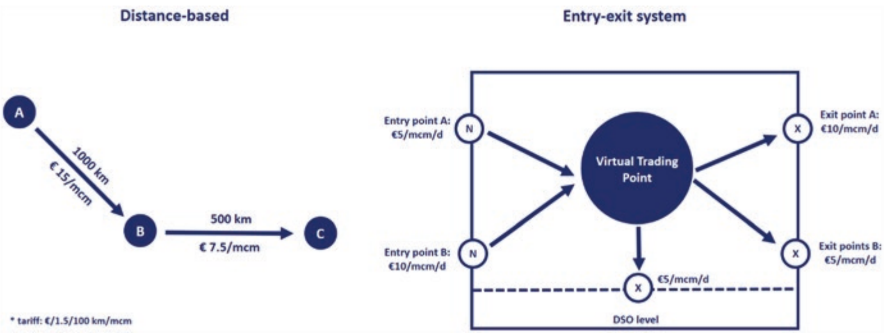


Fig. 2.8 Simplified scheme of tariff structures. (Source: Author)

Distance-based tariffs are typically used in the case of long-distance, intercontinental pipelines with a relatively simple point-to-point structure. Entry-exit models are commonly applied to more complex pipeline systems with multiple branches and interconnections.

The actual level of the pipeline tariff will ultimately depend on (1) initial unit investment cost; (2) expected rate of return and (3) additional transit payments in the case of transit.

Given that capital expenditure accounts usually for over 90% of total costs incurred through the lifespan of a gas pipeline system, tariff rates are intimately linked to the initial unit investment costs. Figure 2.9 illustrates this close interplay. Pipeline systems built in challenging environment (such as mountainous terrain or ultra-deep offshore) and/or with a suboptimal pipeline design will usually have high unit investment costs (over $80,000/km/inch), which in turn requires higher tariff rates to make the project financially viable. Pipelines with a relatively low unit investment cost (below $50/km/inch) can offer more competitive transport tariffs.

The transportation tariff is typically reflective of the expected return by the project developers (and lenders). This usually translates to the target return, used to calculate the target revenue. The target revenue will in turn determine the tariff, equating to total annual revenue/annual contracted capacity.

The transit fees paid by the operators of international pipelines crossing third-party countries will depend greatly on the bargaining power between the two countries, their (geo) political relationship and the potential (economic and political) benefits the transit country might receive from the transit pipeline. Transit fee payments can be paid either in cash or in kind. The Draft

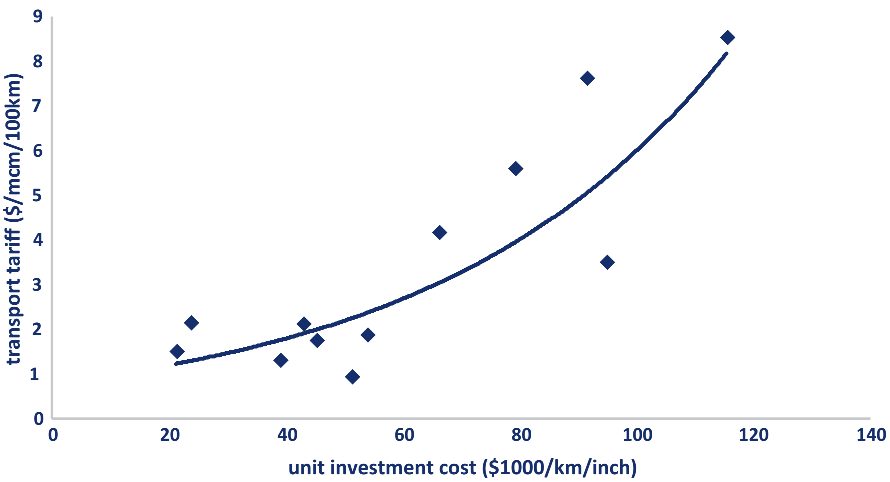


Fig. 2.9 Unit investment costs and transport tariffs of major international pipelines (2000–2020). (Source: Author based on publicly available information and industry estimates)

Transit Protocol of the Energy Charter requires that transit tariffs should be objective, reasonable, transparent and cost-based, “including a reasonable rate of return” (Energy Charter 2003).

Given the high variance of unit investment costs, transportation tariffs of international pipelines will vary in a wide range, from ~$1/mcm/100 km to over $10/mcm/100 km, translating into $0.5/mmbtu/1000 km at the lower end to over $2.5/mmbtu/1000 km for the most expensive pipeline routes.

2 LNG

Liquefied natural gas (LNG) is produced by cooling down methane to -162 °C. This effectively reduces its volume by ~600 times and as such allows for a more flexible way of transportation than through pipelines which have a fixed route by definition. Internationally traded LNG is transported via LNG carriers (LNGCs); however, smaller volumes of liquefied natural gas are also transported via trucks or railroad, typically serving local market as “virtual pipelines” (see Box 2.1).

First experiments with methane liquefaction date back to the beginning of the nineteenth century, when the British chemist Michael Faraday successfully chilled methane into liquefied form. The world’s first liquefaction plant was built in 1912 in the United States in West Virginia for peak shaving.[2] An LNG facility was built in Cleveland, Ohio, in 1941. International LNG trade started in October 1964, with the first commercial shipment delivered by the LNG carrier Methane Princess from Algeria’s Arzew GL4-Z liquefaction plant to Canvey Island in the United Kingdom (GIIGNL & SIGTTO 2014).

Global LNG trade grew from less than 50 bcm/year in 1970s to an average of 200 bcm/year through the 2000s and overpassed the 500 bcm mark in 2020, accounting for over 10% of global gas consumption and for over half of internationally traded gas.

The LNG value chain—not including upstream development—consists of three main components:

1. the liquefaction terminal: including pre-treatment and liquefaction units, storage tanks and an LNG loading jetty to load the LNG carrier via cryogenic pipes;
2. transportation via large LNG carries either by the buyer (free-on-board) or by the seller (delivery ex-ship);
3. a regasification terminal: including LNG unloading arms, storage tanks, vaporizers, odorization and metering stations and send-out to the transmission system.

[2] LNG peak shaving facilities store liquefied natural gas to meet short-term demand fluctuations.

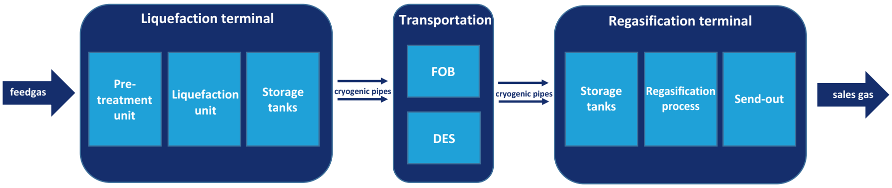


Fig. 2.10 Simplified scheme of the LNG value chain. (Source: Author)

Similarly to long-distance gas pipeline systems, the LNG value chain is characterized by high upfront investment costs and relatively small operating expenses. Consequently, the commercial contracts underpinning the development of LNG projects will show similar traits to the contractual arrangements necessary to mitigate the investment risks associated with pipeline systems (volume, term and tariff commitment) (Fig. 2.10).

Whilst this chapter will focus on the economics of the LNG value chain as described above, it is important to highlight that the costs associated with the upstream development of the reserve base supplying the liquefaction terminal (the cost of the feedgas) can significantly alter the overall economics of a project. The breakeven price of the feedgas can vary in a wide range, from below zero[3] to above \$5/mmbtu in the case of difficult-to-develop reserves (such as coal seam gas). Moreover, the distance between the upstream production facilities and the liquefaction terminal can contribute to the overall costs, in particular if it necessitates the build-up of an additional gas pipeline system.

2.1 Liquefaction Terminals

Liquefaction terminals are arguably the most complex and most costly components of the LNG value chain accounting for over half of total investment costs and operating expenses (when excluding upstream development). The following section provides an overview of their CAPEX structure, recent evolution of unit investment costs and description of typical operating expenses. This will be followed by the presentation of project structures and their contractual features.

2.1.1 CAPEX Structure

The CAPEX of an LNG project will ultimately depend on the liquefaction plant's production capacity (usually expressed in million ton per year, mtpa) and the unit investment cost (expressed in \$/ton per year, \$/tpa).

A liquefaction terminal typically consists of the following facilities, defining its CAPEX structure:

[3] A typical case is when the resource base is sufficiently rich in natural gas liquids (such as ethane, propane, butane, isobutene and pentane) to cover development costs of field.

1. Gas treatment unit: the incoming feedgas needs to be cleaned and purified to obtain pipeline-compatible gas. This includes the removal of CO_2 and sulphur (referred to as “sweetening” of gas), dehydration (to make it water free and hence avoid any icing during the liquefaction process) and the removal of mercury.
2. NGL and fractionation units: natural gas liquids (such as propane and butane) are separated from gas stream to obtain lean gas. Higher value NGLs (such as propane and butane) are separated into individual products for sale, generating additional revenue streams and hence improving project economics. The gas treatment and fractionation units usually account for 10–15% of the CAPEX.
3. Liquefaction unit: the lean, clean and dried gas is cooled down to -162°C through the application of a refrigeration technology, typically consisting of several consecutive cooling cycles (called an “LNG train”). The refrigeration and liquefaction units can account for 30–40% of the liquefaction plant’s CAPEX.
4. Storage: liquefied natural gas is stored in large storage tanks before being unloaded via the product jetty through cryogenic pipelines. Besides optimizing production of the liquefaction unit, storage allows for enhanced LNG tanker scheduling flexibility and can serve as a back-up in the case of planned or unplanned maintenance. Most of LNG storage tanks are above ground with a double-walled design and insulated. Storage and unloading facilities account approximately for one-quarter of the CAPEX.
5. Utilities and offsites: due to their remoteness, liquefaction terminals usually rely on their own utilities for power generation, water supply, transport logistics and so on. These additional cost elements typically account for 20–25% of the project CAPEX.

Figure 2.11 provides an illustrative CAPEX breakdown, which could vary substantially depending on a number of factors, including external conditions, such as quality of feedgas, or remoteness of the terminal.

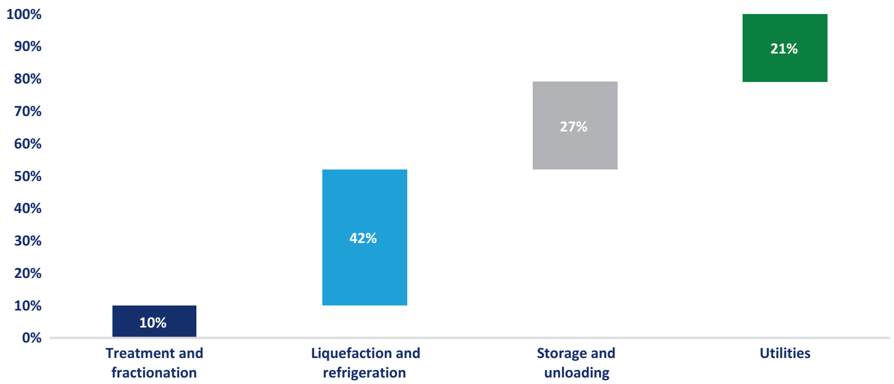


Fig. 2.11 Liquefaction terminal CAPEX breakdown. (Source: based on Songhurst (2018))

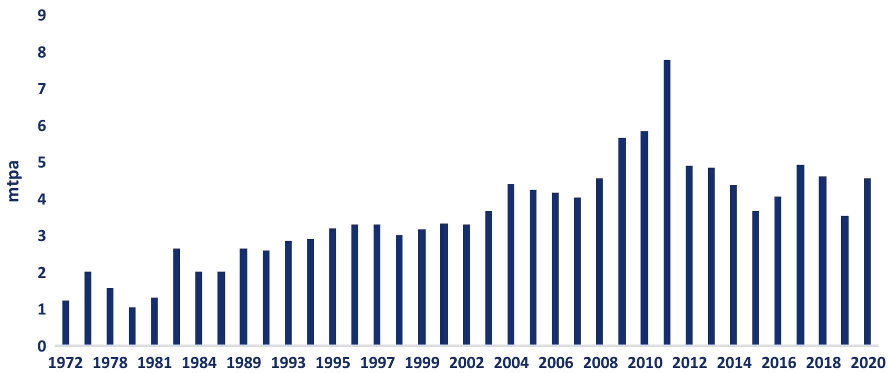


Fig. 2.12 Average nameplate capacity of liquefaction trains by commissioning year. (Source: based on ICIS LNG Edge)

2.1.2 Unit Investment Costs

The evolution of unit investment costs has been cyclical through the last couple of decades. Historical data suggest that the metric cost of liquefaction plants decreased from an average of \$600/tpa during the 1970s and 1980s to below \$400/tpa through the first half of 2000s. This has been partly driven by economies of scale: the average train size more than doubled over that period, from below 2 mtpa in the 1970–1980s to almost 4 mtpa in the first half of 2000s—and eventually reaching their peak of 7.8 mtpa with the commissioning of Qatar's mega-trains in 2009–2011 (Fig. 2.12).

However, liquefaction costs increased significantly over the last decade. According to the International Gas Union (IGU), the average unit cost of liquefaction plants more than doubled from \$404/tonne in 2000–2008 to over \$1000/tonne between 2009 and 2017 (IGU 2018).

This has been partly driven by the fact that a relatively high number of projects have been developed simultaneously, driving up demand for engineering, procurement and construction (EPC) services and the cost of labour. The cost inflation has been particularly felt by the developers of greenfield projects, for which unit cost practically tripled from \$527/tonne to \$1501/tonne over the same period. Projects in Australia (where unit costs went above \$2000/tpa) have been confronted with availability of skilled labour, high logistic costs, exchange rate shifts and construction delays (IGU 2018).

In the case of brownfield projects, which usually benefit from existing infrastructure, unit costs have been increasing less significantly, by just over 40% from \$320/tpa in 2000–2008 up to \$458/tpa in 2019–2017. This includes LNG terminals in the United States (such as Cameron, Freeport or Sabine Pass), which have been originally developed as LNG regasification terminals. The addition of liquefaction plants on those sites required less important terrain preparation works, whilst further savings could be made on utilities and storage tanks development (IGU 2018).

The average metric cost of projects currently under construction is ~$850/tpa. This is certainly lower than the highs experienced through the 2010s (mainly due to locational factors), but still considerably higher when compared to the unit investment costs of the early 2000s.

The efforts of project developers to reduce investment costs include:

- Modularization: an increasing number of project developers is choosing to use pre-fabricated modular units to offset some of the onsite construction expenses (where labour costs tend to be higher). Whilst the use of modular units has its own logistical challenges, it has been estimated by various consultancies that modularization can reduce the CAPEX of liquefaction plants built in remote areas by 5–10% (McKinsey 2019).
- **The return of large trains**: whilst mega-trains clearly demonstrated economies of scale through improved capital and process efficiency, they naturally require a larger reserve base and more capital at risk, which hindered their development since the commissioning of Qatar's mega-trains in the late 2000s. The average train size of projects under construction is about 25% higher compared to the ones commissioned between 2012 and 2018, mainly due to projects in Canada, Mozambique and Russia—which all have train sizes over 6.5 mtpa. Moreover, Qatar's announced expansion project (which would increase the country's liquefaction capacity from 77 mtpa in 2020 to 126 mtpa by 2027) will be based on mega-trains with a capacity of ~8 mtpa.
- **Floating liquefaction (FLNG) facilities** allow for a more cost-optimal development of stranded gas reserves. The first FLNG started operations in 2017 in Indonesia (Petronas' PFLNG Satu with a capacity of 1.2 mtpa), followed by Cameroon FLNG in 2018 (2.4 mtpa), Prelude FLNG in Australia (3.6 mtpa) and Tango FLNG in Argentina (0.5 mtpa) both in 2019. Whilst FLNG certainly can optimize upstream development costs, the average unit cost per liquefaction is relatively high (~$1400/tpa) when compared to onshore liquefaction facilities. One should note that FLNG projects **based on vessel conversions** (such as Cameroon FLNG) can have substantially lower costs (~$500–700/tpa) than greenfield, purpose-built FLNG vessels, further improving the overall project economics.

As presented in Fig. 2.13, LNG liquefaction costs can vary from ~$200/tpa to well above $2000/tpa, which naturally translates into a wide range of break-even costs (usually expressed in $/mmbtu). On average, liquefaction break-even costs are in the range of $2–3/mmbtu.

2.1.3 OPEX

As a thumb of rule, operating expenses of a liquefaction plant account between 3 and 5% per year of the initial capital investment. This is significantly higher when compared to the operating expenses of gas pipeline systems and is

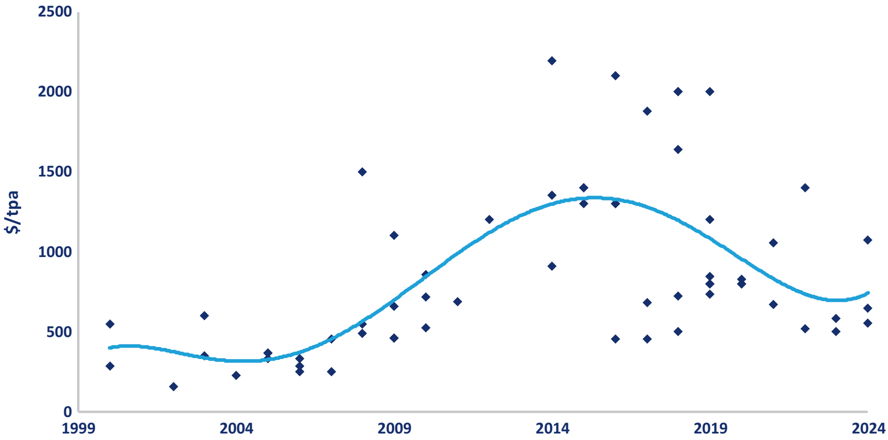


Fig. 2.13 Unit investment costs of LNG liquefaction projects (2000–2024). (Source: Author based on Songhurst (2018), publicly available information and various industry estimates)

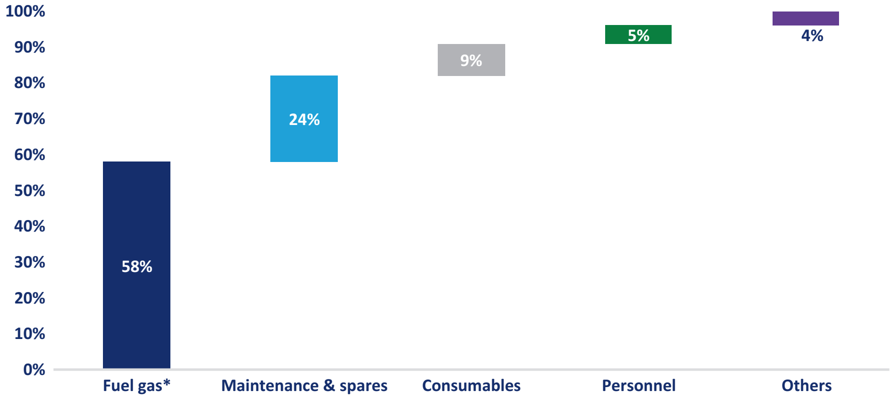


Fig. 2.14 Liquefaction plant OPEX breakdown. Assuming cost of fuel gas at $5/mmbtu. (Source: based on Songhurst (2018))

primarily due to the energy-intensive nature of the liquefaction process (Fig. 2.14).

Depending on the liquefaction process used, plant design and ambient temperatures, between 8 and 12% of the feedgas entering the liquefaction terminal is used to meet the energy requirements of the liquefaction plant (primarily to run the steam or gas turbine drivers powering refrigerant compressors). As such, fuel gas expenses can alone account for over half of the OPEX of a plant.

Other cost elements include expenses related to maintenance works, purchase of consumables (chemical products used for the refrigeration process), salaries of the personnel and insurance.

2.1.4 *Project Structuring and Contract Design*

Considering the high upfront investment costs of LNG liquefaction plants, project developers will seek to mitigate investment risks through risk sharing mechanisms incorporated in the project structure itself and the design of commercial contracts underpinning the procurement of feedgas on one hand and the market of sales gas/liquefaction capacity on the other hand.

Three basic types of commercial structures can be distinguished:

1. Vertical integration: the production of the feedgas, the ownership and operation of the liquefaction plant and the sale/export of the produced LNG are concentrated in one single commercial entity. The project revenues are derived from the sale of LNG via long-term sale and purchase agreements (SPAs).
2. Merchant model: the owner and operator of the liquefaction plant is a different commercial entity from the developer(s) of the upstream assets and supplier(s) of feedgas. This necessitates the conclusion of a gas sales agreement (GSA) between one or multiple upstream companies and the LNG project company. In essence, the GSA ensures the financial revenue stream of the upstream company on one hand and the supply of feedgas to the LNG project company on the other hand. The revenue stream of the LNG project company is derived from the sale of LNG via SPAs.
3. Tolling structure: the owner and operator of the liquefaction plant provides liquefaction services to its customers. The revenue stream of the LNG project is ensured by the tariff payments received from its customers under (typically) long-term liquefaction capacity agreements. The revenue stream of the customers of the LNG project company are usually ensured through long-term LNG SPAs (Fig. 2.15).

Furthermore, hybrid models can emerge. For instance, an LNG project company might offer in a bundled manner liquefaction capacity (for a fixed fee

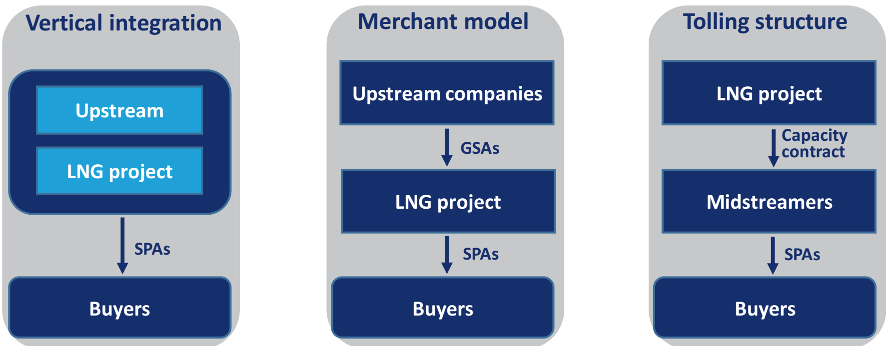


Fig. 2.15 LNG project structuring—basic models. (Source: Author)

indexed to inflation) and sourced feedgas supply (indexed to a given hub) to its customers (e.g. Cheniere's Sabine Pass or Corpus Christi projects)

Both LNG liquefaction capacity contracts and LNG SPAs have similar traits to gas transportation agreements:

- Term commitment: whilst the duration of SPAs went down, from an historical average of over 20 years to below 15 years for the contracts concluded between 2015 and 2019, liquefaction capacity agreements are typically signed for a duration of ~20 years;
- Volume/capacity commitment: both liquefaction capacity contracts and LNG SPAs underpinned by take-or-pay commitments (please refer to Chap. 20 of the Handbook) with limited volume flexibility;
- Price/tariff commitment: SPAs include a negotiated price formula applicable for the entire duration of the contract with eventual revision clauses (please refer to Chap. 20 of the Handbook). Liquefaction contracts are typically based on a fixed tariff (reflective of the breakeven cost of the project and expected margin of the developers) indexed to inflation;
- Destination commitment: historically LNG SPAs typically included destination restrictions (providing market segmentation influence to the seller). Whilst those clauses still exist in legacy contracts, they are becoming increasingly rare in new SPAs due to the resistance of buyers amidst an increasingly liquid and interconnected global gas market. The International Energy Agency's Global Gas Security Review 2019 shows that almost 90% of long-term contracts signed in 2019 had no fixed destination (Fig. 2.16).

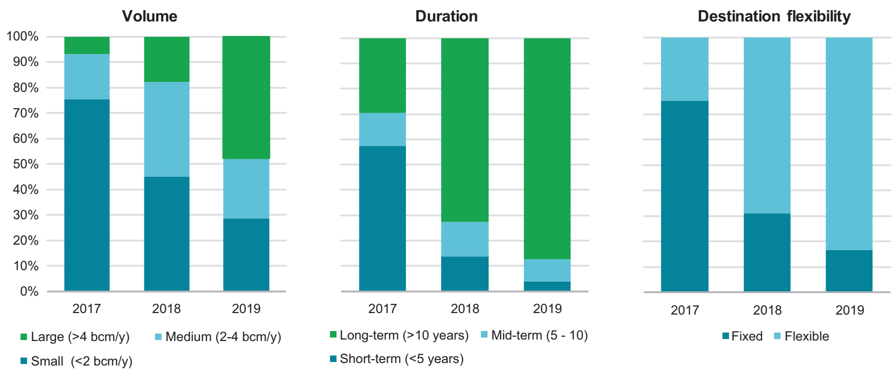


Fig. 2.16 Recent LNG contracting dynamics. (Source: International Energy Agency (2019))

2.2 LNG Shipping

Internationally traded LNG is transported via large, double-hulled vessels, with specifically designed cargo containment systems able to keep LNG at atmospheric pressure and at temperatures close to -162 °C.

The obligation of shipping LNG will depend on the contractual terms fixed between the seller and the buyer in the LNG SPAs and can take the following forms:

- Free-on-board (FOB): delivery takes place at the loading port and the buyer carries the obligation and costs of transportation;
- Delivery ex ship (DES): delivery takes place at the unloading port and the seller carries the obligation and costs of transportation;
- Costs, Insurance and Freight (CIF): the buyer takes title and risk of the LNG at the loading port, but the seller carries the obligation and costs of transportation.

The current section provides an overview of the recent trends in the LNG carriers' fleet, the contractual arrangement underpinning its development and the factors determining the unit cost of LNG transportation by vessels.

2.2.1 LNG Carriers

With a cost averaging at $200 million through the last decade, LNG carriers are fairly considered being amongst the most expensive vessels, second only to the large cruise ships.

By the end of 2019, there were just over 600 LNGCs in operation, including 37 FSRUs (Floating Storage and Regasification Units) and 46 vessels with a transportation capacity of less than 50,000 m^3 (Fig. 2.17).

Two main types of cargo containment systems can be distinguished:

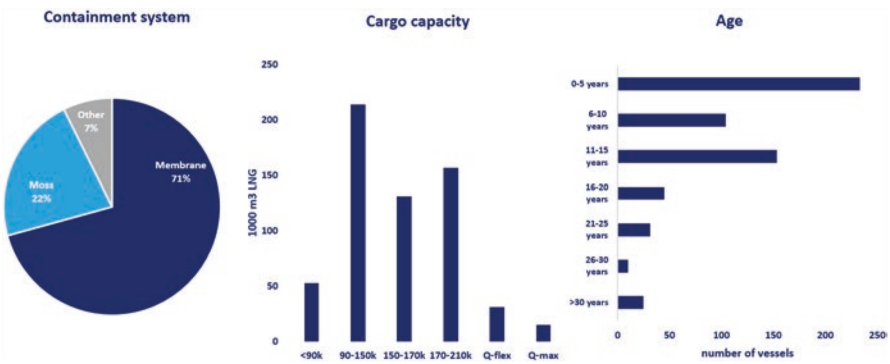


Fig. 2.17 The global LNG fleet. (Sources: based on GIIGNL (2020) and IGU (2020))

- Membrane are practically box-shaped tanks put into the vessel's holds. To cope with the cargo, holds are coated with a cryogenic lining that can withstand the load. Envelopes, known as membranes, contain the LNG at a temperature of -163 °C, sealing it with a totally impermeable layer between the liquid cargo and the vessel's hull, while also limiting cargo loss through evaporation. Membrane-type systems account today for over 70% of containment systems;
- Moss type consists of insulated independent spherical tanks constructed from aluminium alloy and designed to carry LNG at cryogenic temperatures and at a pressure close to atmospheric pressure. The tanks are encased within void spaces and situated in-line from forward to aft within the hull.

Both containment systems aim to minimize the evaporation of LNG (boil off gas, BOG). Typically, between 0.1 and 0.15% of the cargo evaporates per day during the voyage. Newer vessels are designed with lower BOG rates, with the best-in-class purporting rates as low as 0.08% (IGU 2018).

There has been a general trend towards larger cargo capacity, increasing by almost 30% from an average of 125,000 m^3 through the 1970s and 1980s to over 160,000 m^3 since the mid-2000s. The largest LNGCs (Q-max, with a capacity of over 260,000 m^3) were commissioned between 2008 and 2011 in line with the start-up of Qatar's mega-trains. According to the International Maritime Organization (IMO) safety requirements, the tanks can be filled up to maximum 98% of their capacity.

The relatively young age of the LNG fleet—with over half of the LNGCs under 10 years of age—is primarily the reflection of the strong growth LNG trade underwent through the last decade, increasing by almost twofold. LNGCs are typically retired/reconverted after reaching an age of 30–35 years.

In terms of propulsion systems, the following main types can be distinguished (IGU 2020):

- Steam turbines: boilers generate steam to run the propulsion turbines and auxiliary engines. The boilers typically use boil-off-gas and can be partially (or in some cases fully) fuelled with heavy fuel oil. They have been the dominating type of propulsion systems in the past, however are gradually losing their market share due to their relatively low thermal efficiency (resulting in high variable operating expenses). They still account for over 40% of propulsion systems under use in 2020.
- DFDE (Dual-Fuel Diesel Electric) are electric propulsion systems powered by dual-fuel, medium-speed diesel engines, which can run both on diesel and on BOG. They are typically 25–30% more efficient than steam turbines.
- TFDE (Tri-Fuel Diesel Electric) are electric propulsion systems which can be powered by diesel, heavy-oil and BOG. Altogether with DFDE, they represent one-third of propulsion systems in use.

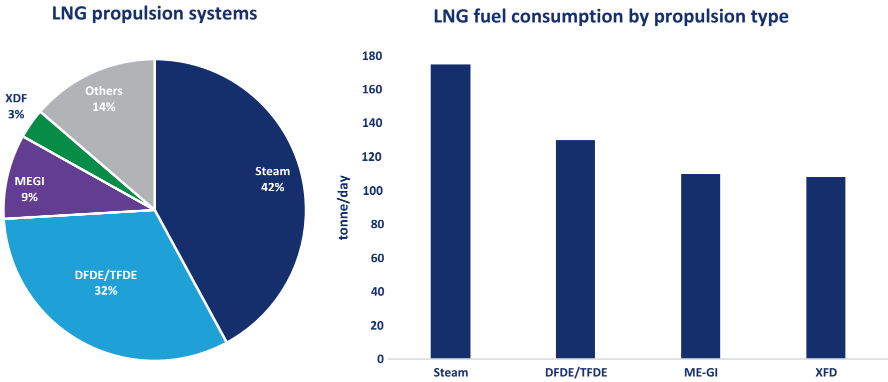


Fig. 2.18 Propulsion systems in use by market share and respective fuel efficiency. (Sources: based on ICIS LNG Edge and IGU (2018))

- ME-GI (Electronically Controlled, Gas Injection) propulsion systems pressurize boil-off gas and burn it with a small amount of injected diesel fuel. They can reach an efficiency 15–20% higher compared to DFDE and currently account for ~10% of propulsion systems in use.
- XDF (Low-Pressure Slow-Speed Dual-Fuel) represents the latest generation of propulsion systems. It burns fuel and air, mixed at a high air-to-fuel ratio, injected at a low pressure. When burning gas, a small amount of fuel oil is used as a pilot fuel. It has a fuel efficiency comparable to ME-GI propulsion systems. Currently, XDF systems account for only a fraction of propulsion systems in use, however they represent almost two-thirds of the vessel orderbook beginning in 2020 (Fig. 2.18).

2.2.2 LNG Chartering

The majority is LNGCs are owned by independent shipowners (with a share of ~70%), who charter LNGCs to market players (including sellers, buyers, aggregators, traders) typically under long-term lease agreements.

The average length of term charter contracts has significantly decreased in recent years, from over 20 years to below 10 years for the contracts concluded between 2008 and 2017. This partly reflects the changing flexibility requirements of LNG players and the shorter duration of LNG SPAs (Fig. 2.19).

Two basic types of long-term charter agreements can be distinguished:

- Time charter: the shipowner provides the LNG carrier and operating services (including the crew, management, maintenance, insurance, etc.). The tariff ("hire rate") hence has two components: a fixed CAPEX-based and a variable OPEX-based. The charterer pays for the voyage-related expenses, including fuel and port costs;
- Bareboat charter: the shipowner simply provides the LNG carrier for which it receives a usually fixed CAPEX-based tariff.

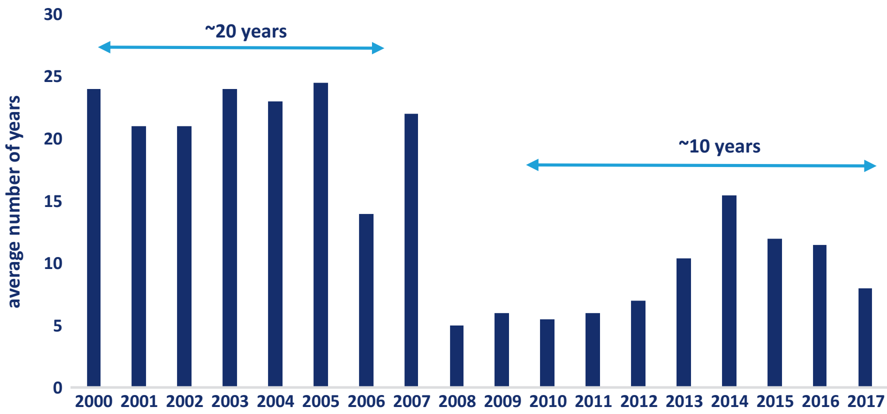


Fig. 2.19 Average length of term charter contracts, per year of contract signing. (Source: based on Adede (2019))

Long-term charter rates remain opaque. Based on the estimates of various price reporting agencies, long-term rates for LNGCs with steam turbine propulsion systems averaged at ~\$50,000/day and ~80,000/day for TFDE LNGCs between 2018 and 2019.

Besides long-term charters, there is an increasing number of LNG vessels available (~10% of the global fleet) for short and spot charter deals, supporting further the development of short-term LNG trading. It should be noted that spot charter rates naturally display greater volatility, with charter rates fluctuating between \$30,000/day and \$200,000/day in 2018.

2.2.3 Unit Cost of LNG Transportation

The unit cost of LNG transportation between a given liquefaction and regasification terminal will depend on a number of factors, including:

- Distance and voyage time: the distance (expressed in nautical miles) typically refers to the length of the entire roundtrip. The voyage time is important given that charter rates are paid per diem and will depend on the speed (expressed in knots=nautical miles[4]/hour) of the vessel. Typically the vessel spends one day at the export terminal and one day at the import terminal with loading and unloading operations, respectively;
- Charter rates typically account for over half of the total transport unit cost. They will vary accordingly to the vessel's size, age, propulsion system and BOG rate, and in the case of spot charters will be largely determined by the prevailing market conditions;
- BOG: will depend on the vessel's BOG rate, the distance and the speed of the vessel;

[4] Nautical miles equate to 1.15 miles and to 1.852 kms.

- Fuel cost is directly proportional to the distance and speed of the vessel. Higher speeds (~19 knots) will naturally translate into higher fuel and/or BOG consumption (vs a vessel running at 14–15 knots can rely purely on natural BOG), whilst lowering the voyage time could reduce chartering costs. The fuel price will depend on market prices for bunker fuel (typically HFO/MDO) and the charterer's procurement strategy. Inclusive of BOG, fuel costs are usually the second most important component of total unit transport costs (over 25% for ST vessels);
- Heel gas requirements of the LNG vessel refer to the minimum inventory level to keep the tanks cool after unloading and potentially necessary for unladen voyages if running on boil-off. It is typically assumed to be ~2–4% of the initial cargo;
- Canal costs has to be paid when transiting through the Suez and Panama canals. They are set by Canal Authorities and are typically in the range of \$300–500,000/transit;
- Port costs: paid per diem during the loading and unloading operations and are usually assumed ~\$100,000/day;
- Brokerage fee: spot charters are typically arranged through specialist brokers, usually attracting 1–2% of the total charter cost;
- Insurance: typically covers the vessel and the cargo, either separately or bundled.

Illustrative LNG shipping costs are provided in Fig. 2.20, for major transport routes. Altogether, the approximative unit transport cost in the case of a DFDE vessel with a cargo capacity of 160,000 m^3, chartered for \$80,000/day and sailing at 18 knots, without the need to transit via canals, would be \$0.04/mmbtu/1000—significantly cheaper than transportation via pipelines (with tariffs ranging between \$0.5 and 2/mmbtu/1000).

2.3 Regasification Terminals

Regasification terminals can be located onshore (representing almost 90% of global regasification capacity in the beginning of 2020) or offshore on Floating

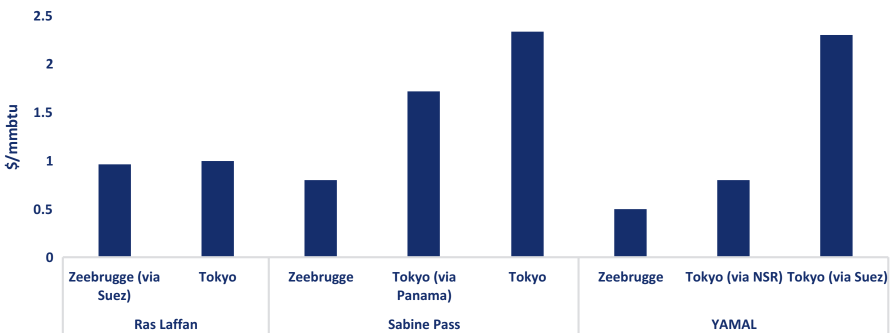


Fig. 2.20 LNG shipping costs for major transport routes for a DFDE vessel. (Source: based on ICIS LNG Edge)

Storage and Regasification Units (FRSUs or FRUs—in the absence of storage capabilities).

A regasification terminal consists typically of the following facilities:

- Unloading arms: LNG is delivered from the LNG carrier via unloading arms, establishing the connection between the vessel's manifold system (piping connection) and the terminal. There are usually several unloading arms and one vapour return arm. It is necessary to send back vapour to the LNG carrier to avoid vacuum conditions. Unloading typically takes 12–16 hours, and the carrier stays about one day in the port.
- Storage: once unloaded, LNG is transported via cryogenic pipelines to storage tanks. Storage tanks allow for tanker scheduling flexibility and optimization of send-out to the downstream market. They have similar design to the ones located at liquefaction terminals and primarily serve tanker scheduling flexibility and optimization of send-out (and hence sales). It is worth to note that in markets with no significant underground storage capacities, LNG storage can enhance security of supply.
- Vaporizers: the LNG sent from the storage tanks is regasified with vaporizers. Four basic types can be distinguished: (1) open rack vaporizers using seawater for the heat necessary to vaporize LNG; (2) submerged combustion vaporizers using natural gas produced by the terminal and pass the hot gases into a water bath containing a tubular heat exchanger where LNG flows; (3) intermediate fluid vaporizer has two levels of thermal heat exchange, first between LNG and an intermediate fluid such as propane and between the intermediate and a heat source (typically seawater); (4) ambient air vaporizers using the heat from the air (usually applied at smaller regasification terminals).
- Send-out: once regasified, natural gas flows to the pressure-regulating and metering station, before being sent-out to the national gas transmission system. Depending on the configuration of the LNG regasification terminal, natural gas can be odorized in an odorizing station before leaving the terminal.

Onshore regasification terminals have significantly lower unit investments costs compared to liquefaction terminals, averaging at ~\$250/tpa between 2013 and 2017. However, one should note that this represents a significant cost-escalation compared to the projects commissioned between 2006 and 2012, with an average unit investment cost of \$115/tpa. The rise in unit costs has been driven by higher expenses associated with EPC contracts and by the general trend towards larger storage tanks.

Offshore regasification terminals have usually lower metric costs (~\$100/tpa), as they require less terrain preparation and ground work. FSRUs are often reconverted LNG carriers, which tend to lower their unit costs as well. They typically have shorter lead times (e.g. Egypt's second FSRU project has been implemented in a record time of 5 months) compared to conventional onshore

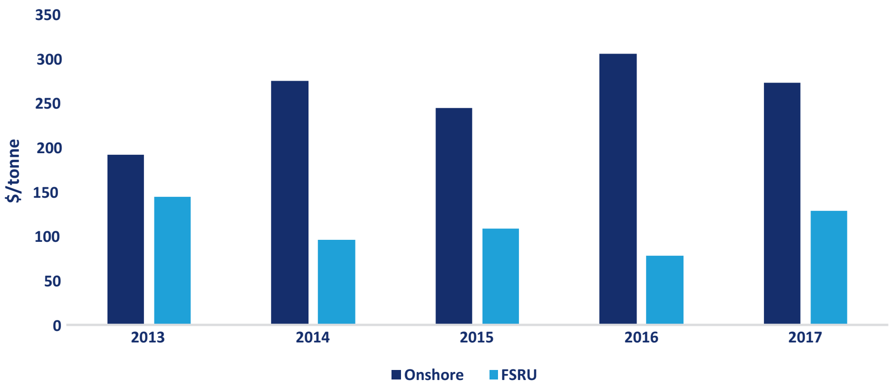


Fig. 2.21 Regasification unit investment costs (2013–2017). (Source: based on IGU (2013–18))

regasification terminals. This can be of particular interest in markets which experience near-term gas demand growth or potential supply-demand imbalances. On the flipside, they tend to have higher operating expenses (as the vessel is most commonly leased), lower storage capability and no option for future expansions. Since the first FSRU has been commissioned in 2005, offshore regasification has been growing considerably to over 100 mtpa by the beginning of 2020 (Fig. 2.21).

Regasification capacity is usually booked under long-term capacity contracts. In liberalized markets, under the principle of use-it-or-lose it, unused capacity has to be offered on the secondary market, for instance, via auctions. Regasification fees typically range between \$0.3 and \$1/mmbtu.

3 Conclusion

Transportation typically accounts for over half of total costs occurring through the value chain of internationally traded natural gas and hence greatly influences its cost competitiveness.

Both long-distance pipeline systems and LNG have high upfront investment costs, requiring risk sharing mechanisms being incorporated either in the project structure itself (primarily via vertical integration) and/or into the design of commercial contracts between the project developers and their customers.

Risk sharing typically translates by the buyers' long-term commitment to pay a fixed tariff (reflective of the breakeven cost of the project and expected margin of the project developers) for the liquefaction/transportation capacity purchased on a firm basis and underpinned with ship-or-pay clause. Whilst gas sales contract structuring has been evolving towards a greater commercial flexibility (allowing for shorter term deals with less firm commitments and more diverse price formulae), transportation contracts—especially when underpinning the development of new infrastructure—have largely retained their conservative design, allowing project developers (and their lenders) to recover the initial high upfront investment cost through a stable revenue stream.

When comparing transportation costs via LNG vs long-distance pipeline systems, one should note that in the case of LNG the majority of costs—both initial investment and operational expenses—occur upfront, at the stage of liquefaction and then increase relatively slowly (less than \$0.05/mmbtu/1000 km) during the transportation phase via LNGCs. In contrast, in pipeline systems transportation costs increase more swiftly (\$0.5–2.5/mmbtu/1000 km) with the travelled distance.

Consequently, LNG becomes cost competitive with pipeline transportation only on long distances, typically beyond several thousand kms. This is illustrated in Fig. 2.22, comparing the delivery costs of LNG (assuming an average ~\$2.4/mmbtu liquefaction and 0.4/mmbtu regasification fee) transported via an LNGC with a typical long-term hire of \$80,000/day versus pipelines operating under a relatively low tariff rate of \$0.5/mmbtu/1000 km and a higher tariff of \$1/mmbtu/1000 km.

Considering the above-described assumptions, LNG becomes cost competitive with pipeline transportation for distances above 3000–7000 kms. However, as discussed through the chapter each pipeline and each LNG project is unique and unit investment costs vary in a wide range for both type of infrastructure, which can significantly alter the "breakeven distance" between LNG and long-distance pipeline systems.

The high transportation costs of natural gas compared to other primary fuels (such as coal or crude oil) is severely weighing on the cost competitiveness of methane molecules. The gas industry will need to continue to work on optimizing transportation costs.

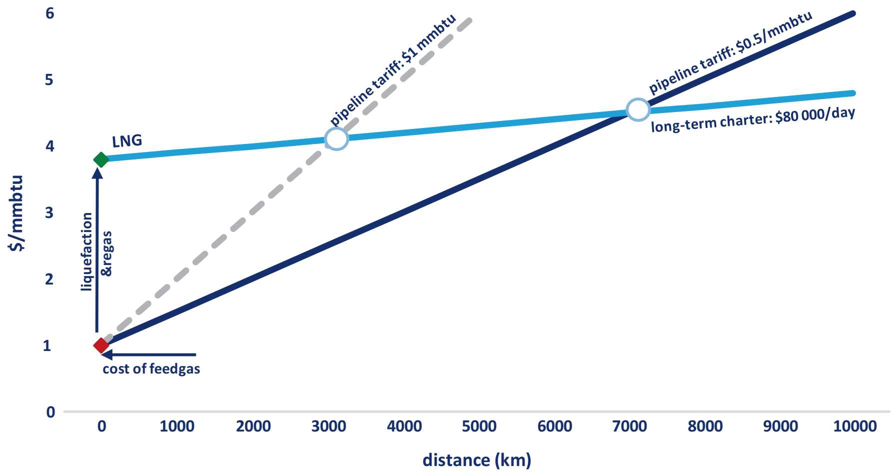


Fig. 2.22 LNG versus pipeline transportation costs. (Source: Author)

The unit investment cost of liquefaction plants has been decreasing since the highs (over $2000/tpa) reached in the early 2010s. However, the average metric cost of projects currently under construction (~$850/tpa) is still approximately twice the unit investment cost of projects commissioned between 2000 and 2008. This highlights the potential cost reductions which might be reached through improved project management, plant design optimization and usage of innovative construction approaches (e.g. modularization, vessel conversions to FLNG).

Given the maturity of technology, the cost reduction potential in gas pipeline systems is considered to be rather limited. The design of newly built pipelines will increasingly need to take into account the requirement of improved compatibility with low-carbon gases, including hydrogen (see Chap. 4 of the Handbook, *Economics of hydrogen*), biomethane and synthetic gas.

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