European Commission

JRC TECHNICAL REPORT

EU Gas Transmission Network Facilities Review

Inventory, operation and failure modes of the main components of the EU gas system. An information source to gas risk assessments.

Calisto, H.

Gandossi, L.

Rodríguez Gómez, N.

Bolado Lavín, R.

2020

Contact information
Name: Ricardo BOLADO LAVÍN
Address: European Commission, Joint Research Centre (JRC), Westerduinweg 3, NL 1755 LE, Petten, The Netherlands
Email: ricardo.bolado-lavin@ec.europa.eu
Tel.: +31 (0) 224565349

EU Science Hub
https://ec.europa.eu/jrc

JRC122592

EUR 30470 EN

PDF ISBN 978-92-76-25201-6 ISSN 1831-9424 doi:10.2760/338818

Luxembourg: Publications Office of the European Union, 2020

How to cite this report: Calisto, H., Gandossi, L., Rodríguez Gómez, N., Bolado Lavín, R., *EU Gas transmission network facilities review. Inventory, operation and failure modes of the main components of the EU gas system. An information source to gas risk assessments*, EUR 30470 EN, Luxembourg: Publications Office of the European Union, 2020, ISBN 978-92-76-25201-6, doi:10.2760/338818, JRC122592.

Contents

Acknowledgements

The authors of this report would like to thank our colleagues Per Loekkemyhr and Vytis Kopustinskas for reviewing it and contributing to improve its quality.

Authors

Calisto, Hugo. European Commission, Joint Research Centre (JRC), Petten, Netherlands.

Gandossi, Luca. European Commission, Joint Research Centre (JRC), Petten, Netherlands.

Rodríguez Gómez, Nuria. European Commission, Joint Research Centre (JRC), Petten, Netherlands.

Bolado Lavín, Ricardo. European Commission, Joint Research Centre (JRC), Petten, Netherlands.

Abstract

This report addresses a review of main EU natural gas transmission network facilities. A review of Liquefied Natural Gas (LNG) regasification terminals, Underground Gas Storage (UGS) facilities, Compressor Stations (CS) and pipelines has been done. Special attention has been paid to identify types, operation modes and main types of failures of these facilities. Reasonable ranges of failure frequencies have also been selected from the available literature. The contents of this report are expected to be relevant as data sources to national and regional Risk Assessments (RA) performed in line with Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply.

1 Introduction

Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply contains among its provisions the obligation to perform Risk Assessments of all national gas systems and of a number of regional Risk Groups formed by Member States that share a strong dependence on specific natural gas sources or on a specific route bringing large quantities of gas to the European Union. Performing these types of Risk Assessments (RA), either national or regional, needs a very good understanding of the gas system of each country and region, and in particular of their respective gas transmission networks.

Gas networks, together with Liquefied Natural Gas (LNG) cargoes, are the means to bring gas from production areas to regions of consumption. Gas networks are typically divided in gas transmission and gas distribution networks, attending to the operating pressure and mission. Gas transmission networks typically operate at high pressure and transport gas over long distances, while distribution networks operate a low pressure and bring gas to the gate of most of the consumers (only a very limited number of large consumers like some gas fired power plants and big factories are directly connected to the transmission network).

Gas transmission networks are the ones most frequently addressed in a RA in line with Regulation (EU) 2017/1938 because of the magnitude of the impact of events that may take place in their many different facilities and components; the impact of events occurring in distribution networks have much more limited consequences. Main elements (facilities and components) of transmission networks are pipelines, compressor stations (CS), LNG terminals, Underground Storage (UGS) facilities, metering stations, blending stations, valves, and regulators.

A RA typically analyses and combines scenarios, their probabilities and consequences. Thus, it is very important to understand what the most important elements of the network that may fail are, how they may fail, what are their immediate effect on the vicinity of the facility, and how likely this to happen is. Over the years, our group has reviewed many national and regional RAs, worked on different networks and collaborated with different gas experts from EU Member States. This work has taken us to consider that the facilities that demand more attention and whose failures have to be considered as much as possible in a RA are Underground Storage facilities, Liquefied Natural Gas regasification terminals, compressor stations and pipelines.

In this report we focus our attention on the following aspects: 1) identifying and collecting information about a significant number of facilities of the types mentioned in the previous paragraph, although not making a real inventory because of the unavailability of public information (in many cases even commercial information is scarce), 2) understanding the way each type of facility works, 3) understanding and categorising, as much as possible, the types of failures that they are subject to, and 4) whenever possible, identifying and selecting likely failure frequencies for the different facilities and failure modes. This last point has been particularly difficult because of the scarcity of open literature on the subject.

This report is structured as follows. Section 2 gives a very brief overview of the EU gas transmission network. Section 3 is dedicated to Underground Storage facilities, their types and operation, their components and characteristics, and their main failure modes. Section 4 is dedicated to Liquefied Natural Gas regasification terminals, their main types and operation. A short description is already done of each terminal in operation in the EU. In the last parts of this section failure modes and frequencies of incidents are also addressed. Section 5 addresses compressor stations, showing types and their operation. A sub-section is dedicated to reliability data of a number of types of compressor stations. Section 6 is dedicated to pipelines, stressing the data available on pipeline failures and related frequencies. Finally, section 7 contains the main conclusions of the study. Two annexes contain an inventory and some more detailed information about UGS and LNG facilities in the EU.

2 The European gas transmission network: past and future

The European gas network has been established gradually during the last 80 years. Initially, the European gas system was developed around national gas fields in Southern France, Northern Italy, Germany and Romania. In the 1960s the large gas field of Groningen was found in the Netherlands. . It was in the 1980s that the large scale gas import from Norway, Russia and Algeria took over as the main source of gas supply in Europe. In the 1990s gas was introduced and developed in Greece, Portugal and Ireland. After 2000 the focus has been on connecting the UK gas market to the continent and the Norwegian gas fields, connecting new Member States to the EU-integrated system, creating new import channels as pipelines from North Africa, the Caspian Sea and establishing new LNG import facilities.

In general, the European gas infrastructure is quite young and replacement is not considered a major issue in most Member States, while a key focus of the EU's Energy Union Strategy is ensuring gas can flow easily across borders within the Union. During the 1990s, when most national natural gas markets were still monopolised, the European Union and the Member States decided to open these markets gradually to competition. The first liberalisation directive (First Energy Package) for gas was adopted in 1998, to be transposed into Member States' legal systems by 2000. The Second Energy Package was adopted in 2003, its directives to be transposed into national law by Member States by 2004, with some provisions entering into force only in 2007. Industrial and domestic consumers were then free to choose their own gas suppliers from a wider range of competitors. In April 2009, a Third Energy Package seeking to further liberalise the internal electricity and gas markets was adopted, amending the second package and providing the cornerstone for the implementation of the internal energy market.

Currently the European internal market is functioning reasonably well. It is considered that around 75% of gas in the European Union is consumed within a competitive liquid market (IEA, 2018), in which gas can be flexibly redirected across borders to areas experiencing spikes in demand or shortages in supply. The bidirectional capacity, promoted for most EU cross-border points with the EU Regulation on security of gas supply, has contributed in this regard. There are a few areas where markets and physical interconnections need further development. For example, roughly 40%, of the EU's LNG regasification capacity cannot be accessed by neighbouring states (IEA, 2018), and some countries in central and southeast Europe still have limited access to alternative sources of supply.

However the debate on Europe's gas transmission system is shifting from traditional concerns around ensuring security of gas supply to questions over the role of gas infrastructure in a decarbonising European energy system. As the European Union anticipates pathways to reach carbon neutrality in the Commission's latest 2050 strategy, options to decarbonise the gas supply itself are gaining attention –with the use of low and neutral GHG gases. Natural gas infrastructure must evolve to fulfil additional functions beyond its traditional role of transporting fossil gas from the production site to the boiler. Europe's gas infrastructure will need to adapt to the demands of sustainable development.

2.1 The natural gas supply chain

There are abundant natural gas sources in the world and, in comparison to oil, they are better geographically spread which makes natural gas far more attractive from a geopolitical point of view. In any case, natural gas needs to be transported from the source to the point of consumption. There are two common means of transport: pipelines and liquefied natural gas, both of them requiring large investments. The major build-up of LNG facilities throughout the world in recent years is due to the fact that gas transportation in pipelines is not practical in most cases of long sea distances (more than 800 km). Apart from pipelines and LNG terminals there are other components that are key to the transport and operation of the gas system and that are part of the natural gas supply chain.

The gas supply chain comprises several phases (see Figure 1) that allows bringing gas from the wells to the burn pit of a boiler. The main steps of the natural gas supply chain are summarised in:

<u>Gas exploration and production</u>. It includes drilling, extraction, and recovery of the fuel from underground, either onshore or subsea.

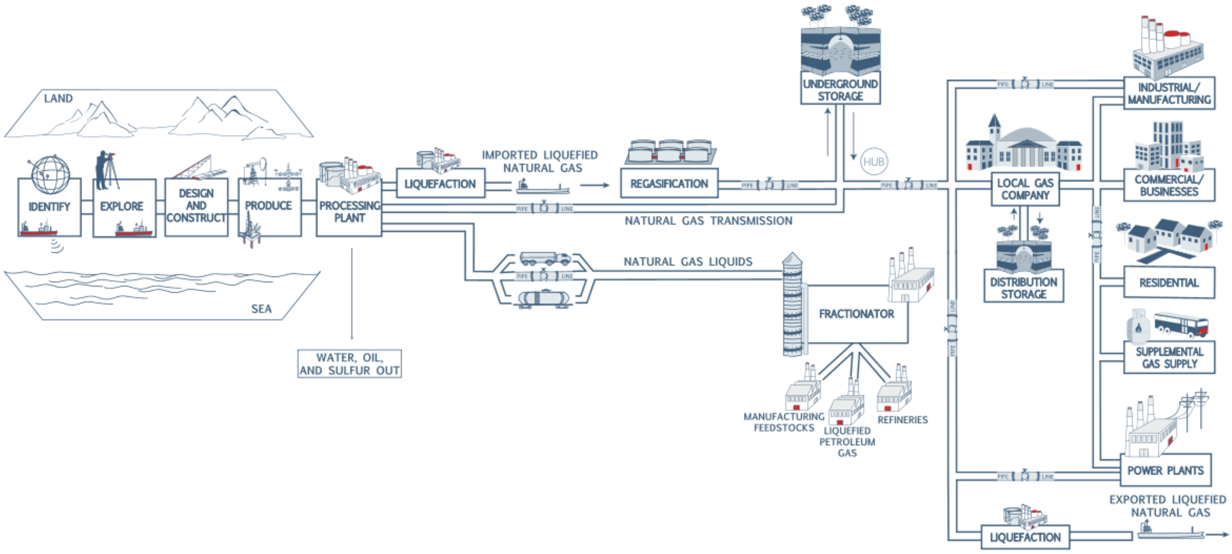
<u>Processing plant</u>. Cleaning raw natural gas by separating impurities and the various hydrocarbons and fluids. Processing plants produce dry natural gas with an adequate pipeline quality that can be used as fuel by residential, commercial, and industrial consumers.

Delivery to connected transmission pipelines or liquefaction. Liquefaction occurs at normal atmospheric pressure by super-cooling the natural gas to -160°C, creating liquefied natural gas for ease and safety non-pressurized storage or transport. The reversed process occurs at regasification plants, where the temperature of LNG is increased, typically through seawater vaporizers, transforming it into gas prepared for use.

Transmission, storage and bulk supply to large consumers directly connected to the transmission system and to distribution companies.

Distribution, storage and retailing of gas to residential, commercial and industrial consumers.

Figure 1. The gas supply chain



Source: American Petroleum Institute (API).

Due to the structure of the gas supply chain, natural gas transmission has traditionally been a monopolistic industry. Today it is regulated by specific EU legislation on Third Party Access (EC Regulation 715/2009) and open access to the infrastructure. Gas transmission system operators (TSOs) as well as operators of storage or LNG facilities are required to grant energy companies non-discriminatory access to their infrastructure. They must offer the same service to different users under identical contractual conditions. A number of other specific rules ensuring competition in natural gas apply to the sector and its pipeline systems, such as the existence of independent regulators who ensure the application of the rules or the right to choose or change suppliers without extra charges.

In the following sections the types and main characteristics of the most relevant components of the gas supply chain will be examined with a closer view to the facilities that comprise the European gas system. Underground storage facilities, LNG terminals, compressor stations and pipelines are key elements to transport and make use of natural gas in all demand points. The operation mode of these facilities and the manner in which they can fail are analysed with the aim of understanding better the technical factors that could compromise the security of gas supply.

3 Underground Storage Facilities

The exploration, production, and transportation of natural gas takes time, and the natural gas that reaches its destination is not always needed right away, so it is injected into unique warehouses underground. Traditionally, natural gas has been a seasonal fuel. That is, demand for natural gas is usually higher during the winter, partly because it is used for heating in residential and commercial settings. UGS facilities are developed to supply gas in times of peak demand, playing a vital role in ensuring that any excess supply delivered during the summer months is available to meet the increased demand of the winter months. However, in some Member States where natural gas is used for fired electric generation, demand for natural gas during the summer months can also increase (due to the demand for electricity to power air conditioners). Strategically, underground gas storage provides security of supply in case there are disruptions to production and transmission.

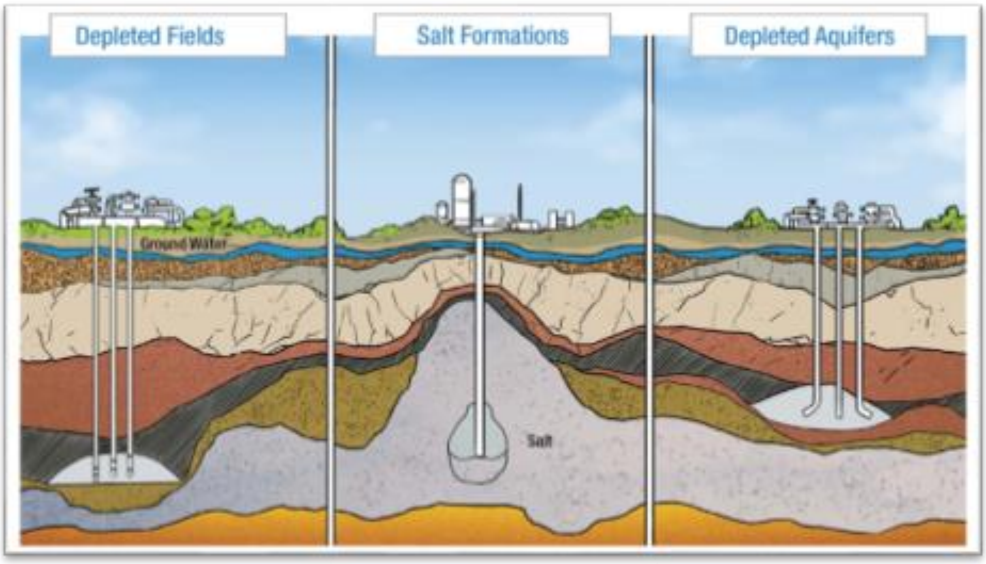
As mentioned, natural gas storage is required for two reasons: meeting seasonal demand requirements, and as insurance against unforeseen supply disruptions. Now, in addition to serving those purposes, natural gas storage is also used by industry participants for commercial reasons; storing gas when prices are low, and withdrawing and selling it when prices are high, for instance.

Natural gas is usually stored underground, in large storage reservoirs. There are three main types of underground storage: depleted gas reservoirs, aquifers, and salt caverns. In addition to underground storage, however, natural gas can be stored as liquefied natural gas. LNG allows natural gas to be shipped and stored in liquid form, meaning it takes up much less space than gaseous natural gas. This sort of storage will be analysed in Section 4, p. 16.

3.1 Types and operation of UGS facilities

Natural gas is most commonly stored underground under pressure in three types of facilities: depleted reservoirs in oil and/or natural gas fields, aquifers, and salt cavern formations (see Figure 2). Each storage type has its own physical characteristics of porosity, permeability and retention capability. And each type has intrinsic costs of maintenance, deliverability rates and cycling capability. All these govern the appropriateness of one or other type for particular applications.

Figure 2. Main types of natural gas UGS facilities



Source: American Petroleum Institute (API).

Specific characteristics of depleted reservoirs, aquifers, and salt caverns can be found below. But in general, it is common for any underground storage facility the reconditioned before injection, to create a sort of storage vessel underground. Natural gas is injected into the formation, building up pressure as more natural gas is added. In this sense, the underground formation becomes a sort of pressurized natural gas container. The higher the pressure in the storage facility, the more readily gas may be extracted. Once the pressure drops to below that of the wellhead, there is no pressure differential left to push the natural gas out of the storage facility. This means that, in any underground storage facility, there is a certain amount of gas that may never be extracted. This is known as physically unrecoverable gas that it is permanently embedded in the formation. In addition to this physically unrecoverable gas, underground storage facilities contain what is known as "cushion gas". This is the volume of gas that must remain in the storage facility to provide the required pressurization to extract the remaining gas. In the normal operation of the storage facility, this cushion gas remains underground; however a portion of it may be extracted using specialized compression equipment at the wellhead.

3.1.1 Depleted Fields

Gas storage in depleted oil or gas fields is the most widespread and generally the least expensive method of storing natural gas in large quantities. They are also the quickest to develop, operate and maintain. They are formations that have already been exhausted of most of their recoverable oil and natural gas. This leaves an underground formation, geologically capable of holding natural gas. In addition, using an already developed reservoir for storage purposes allows the use of the extraction and distribution equipment left over from when the field was productive. Having this extraction network in place reduces the cost of converting a depleted reservoir into a storage facility. Depleted reservoirs are also attractive because their geological characteristics are already well known.

The factors that determine whether or not a depleted reservoir will make a suitable storage facility are both geographic and geologic. Geographically, depleted reservoirs must be relatively close to consuming regions. They must also be close to transportation infrastructure, including trunk pipelines and distribution systems. Geologically, depleted reservoir formations must have high permeability and porosity. The porosity of the formation determines the amount of natural gas that it may hold, while its permeability determines the rate at which natural gas flows through the formation, which in turn determines the rate of injection and withdrawal of working gas. In the majority of oil/gas fields, the gas is held in a porous rock which has spaces between the grains, forming an interconnecting, permeable network. The porosity and permeability enables the gas to move through the rock mass. Gas can be injected into the reservoir rock to be stored in the connected pore spaces. As gas is removed from the oil/gas field, the pressure in the reservoir depletes and water invasion occurs.

Depleted fields are ideal UGS facilities to meet the increases of seasonal demand, known as base load storage capacity. Base load facilities are capable of holding enough natural gas to satisfy long term seasonal demand requirements. Typically, the operation rate for natural gas in these facilities is a year; natural gas is generally injected during the summer (non-heating season), which usually runs from April through October, and withdrawn during the winter (heating season), usually from November to March. These reservoirs are larger, but their delivery rates are relatively low, meaning the natural gas that can be extracted each day is limited. Instead, these facilities provide a prolonged, steady supply of natural gas. Depleted gas reservoirs are the most common type of base load storage facility.

3.1.2 Aquifers

Aquifers are underground porous, permeable rock formations that act as natural water reservoirs. However, in certain situations, these water containing formations may be reconditioned and used as natural gas storage facilities. An aquifer is suitable for natural gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. Aquifers are based upon the same concepts as depleted oil/gas fields, but are a more costly option as they require conditioning and more preliminary work to prove their capability to hold and contain gas under pressure. Their use for natural gas storage usually requires more cushion gas and allows less flexibility in injecting and withdrawing. Aquifer storage is usually only used in areas where no nearby depleted hydrocarbon reservoirs exist.

There are multiple reasons for which aquifers are the most expensive type of natural gas storage facility:

- The geological characteristics of aquifer formations are not as thoroughly known as with depleted reservoirs. Discovering the geological characteristics of an aquifer, and determining its suitability as a natural gas storage facility is needed prior to development of the formation. On the same grounds seismic testing must be performed and the area of the formation, the capacity of the reservoir, the composition and porosity, and the existing formation pressure must all be investigated.
- The associated infrastructure (installation of wells, extraction equipment, pipelines, dehydration facilities, and possibly compression equipment) must be developed.

- Since aquifers are naturally full of water, in some cases powerful injection equipment must be used, to allow sufficient injection pressure to push down the resident water and replace it with natural gas.
- Upon extraction from a water bearing aquifer formation the gas typically requires further dehydration prior to transportation, which requires specialized equipment near the wellhead.
- Aquifer formations do not have the same natural gas retention capabilities as depleted reservoirs. This means that some of the natural gas that is injected escapes from the formation, and must be gathered and extracted by "collector" wells, specifically designed to pick up gas that may escape from the primary aquifer formation.

All of these factors mean that developing an aquifer formation as a storage facility can be time consuming and expensive.

3.1.3 Salt Caverns

Salt caverns are formed out of existing salt bed deposits. They can be abandoned salt mines (salt beds), with generally shallow depth (few hundreds of metres) and not originally constructed with gas storage in mind, or solution mined caverns (salt domes), created by solution mining during the production of brine and chlorine products. The walls of a salt cavern also have the structural strength of steel, which makes it very resilient against reservoir degradation over the life of the storage facility.

Once a suitable salt dome or salt bed deposit is discovered, and deemed suitable for natural gas storage, it is necessary to develop a "salt cavern" within the formation. Essentially, this consists of using water to dissolve and extract a certain amount of salt from the deposit, leaving a large empty space in the formation. This is done by drilling a well down into the formation, and cycling large amounts of water through the completed well. This water will dissolve some of the salt in the deposit, and be cycled back up the well, leaving a large empty space that the salt used to occupy. This process is known as "salt cavern leaching".

Salt cavern leaching is used to create caverns in both types of salt deposits, and can be quite expensive. However, once created, a salt cavern offers an underground natural gas storage vessel with very high deliverability. In addition, cushion gas requirements are the lowest of all three storage types.

These storage facilities, as they are open vessels, offer high deliverability and are ideal to meet the requirements as peak load facilities. These are intended to have high-deliverability for short periods of time. These facilities cannot hold as much natural gas as base load facilities; however, they can deliver smaller amounts of gas more quickly, and can also be refilled in a shorter amount of time than base load facilities. While base load facilities have long term injection and withdrawal seasons, turning over the natural gas in the facility about once per year, peak load facilities can have turnover rates as short as a few days or weeks. Salt caverns are the most common type of peak load storage facility, although aquifers may be used to meet these demands as well.

3.2 The components of a gas storage facility

As it has been discussed in the previous section, there are different types of UGS facilities designed to meet different requirements. However, the following components are usually common to any UGS facility intended to stock natural gas:

Underground reservoir

Underground reservoirs are geological structures in a porous medium with certain degree of permeability that allows natural gas to be contained. Overlying the porous medium there is an impermeable layer, usually curved or dome-shaped, that prevents the gas from rising to the surface. The bottom part of the porous medium may be sealed by impermeable rock or by water.

Injection and withdrawal wells

Wells are used to transfer gas into and out of the storage reservoir. The most common type of wells are the combined injection-withdrawal which are used to either inject or withdraw gas. However, due to particular reservoir characteristics, it may not be feasible or desirable to inject or withdraw in a particular portion of the reservoir. In those cases there may be separated wells used for injection and withdrawal. There are also the so called observation wells that are used to monitor water migration in the reservoir and determine if gas could escape if it reached there.

Gathering system

The gathering system connects the system of wells with the central point facilities. The most common arrangement is the tree configuration where wells are connected to pipes. Usually, a meter is installed at the wellhead to measure the flow rate of gas to and from an individual well.

Compressor facility

The compressor facility is usually located at some central point near the wells and may be used to compress the gas for injection, for withdrawal or both. The compressors are generally used for injection because the reservoir operating pressure is usually higher than the transmission system pressures. Since the compressors are available, they are often used for withdrawal also in order to increase deliverability. There are cases where a shallow, low pressure field is used for gas storage and the injection is done at pipeline pressure and compressors are used to withdraw the gas.

Central point metering facility

Accurate metering at the central point is essential for good inventory control. Due to the widely different characteristics of the injection and withdrawal flow streams, it is often impractical to measure both streams with a single meter facility.

Central Point Separators

These should be used for both the injection and withdrawal streams. The injection separator prevents any dust and particle matter (also liquids) brought in from the pipeline from contaminating and clogging the wells. The withdrawal separators keeps any sand from the reservoir from entering the pipeline. Both separators protect the compressors.

Dehydrator

A storage reservoir almost always contains some water and may have an active water drive. When dry gas from the pipeline is injected into the storage reservoir, liquid water from the formation will evaporate into the injected gas. The gas will then have too much water to be pipeline quality gas. The gas must be dehydrated on the withdrawal cycle. Commonly, the dehydrators in storage facilities are glycol units.

Transmission line to the pipeline

The transmission line connects the UGS facility central point to the pipeline system.

3.3 Characteristics of the underground storage

There are several features that are used to quantify the fundamental characteristics of an underground storage facility:

- Total gas storage capacity: this is the maximum volume of natural gas that can be stored in an underground storage facility in accordance with its design.
- Total gas in storage: it is the volume of natural gas in the underground facility at a particular time.
- Cushion gas: it is the volume of natural gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season.
- Working gas capacity: it refers to total gas storage capacity minus cushion gas.
- Working gas: it is the volume of gas in the reservoir above the level of cushion gas. Working gas is the volume of gas in the storage reservoir that can be extracted during the normal operation of the storage facility and that it is available to the market. This is the natural gas that is being stored and withdrawn; the capacity of storage facilities normally refers to their working gas capacity. At the beginning of a withdrawal cycle, the pressure inside the storage facility is at its highest; meaning working gas can be withdrawn at a high rate. As the volume of gas inside the storage facility drops, pressure (and thus deliverability) in the storage facility also decreases.
- Deliverability or withdrawal capacity: it is a measure of the amount of gas that can be delivered (withdrawn) from a storage facility on a daily basis. It is usually expressed in terms of million cubic meters per day (Mcm/d), although energy units are also common (GWh/d). The deliverability of a given storage facility is variable, and it depends on factors such as the amount of natural gas in the reservoir at any particular time, the pressure within the reservoir, the compression capability

available to the reservoir, the configuration and capabilities of surface facilities associated with the reservoir, and other factors. In general, a facility's deliverability rate varies directly with the total amount of natural gas in the reservoir: it is at its highest when the reservoir is most full and declines as working gas is withdrawn.

- Injection capacity (or rate): it is the complement of the deliverability or withdrawal capacity. This is the amount of natural gas that can be injected into a storage facility on a daily basis. As with deliverability, injection capacity is usually expressed in Mcm/d, although GWh/day is also used. The injection capacity of a storage facility is also variable, and it is dependent on factors comparable to those that determine deliverability. By contrast, the injection rate varies inversely with the total amount of gas in storage: it is at its lowest when the reservoir is most full and increases as working gas is withdrawn.

None of these measures for any given storage facility are fixed or absolute. The rates of injection and withdrawal change as the level of natural gas varies within the facility. In practice, a storage facility may be able to exceed certificated total capacity in some circumstances by exceeding certain operational parameters. The facility's total capacity can also vary, temporarily or permanently, as its defining parameters vary. Measures of cushion gas, working gas, and working gas capacity can also change from time to time. Finally, storage facilities can withdraw cushion gas for supply to market during times of particularly heavy demand, although by definition, this gas is not intended for that use.

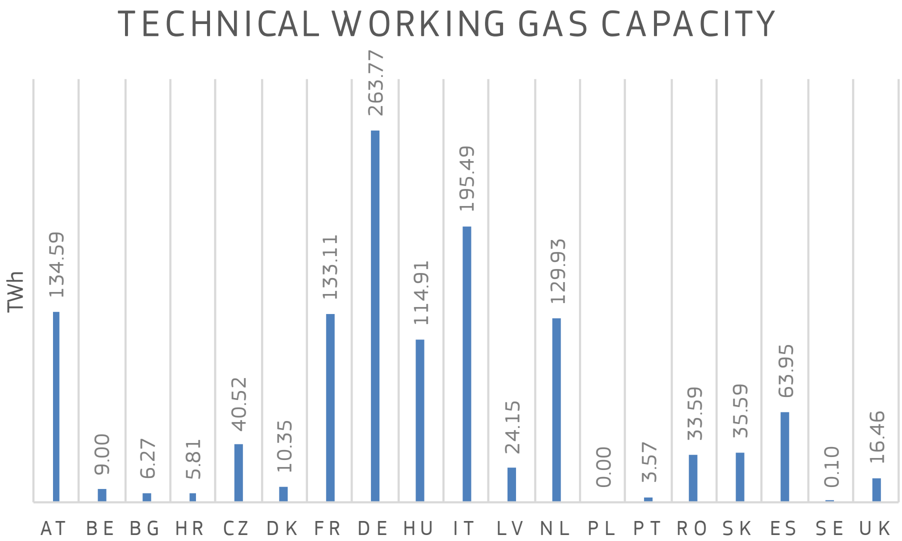
3.4 The European UGS facilities

The storage gas sector in Europe has grown fast since 2006 pushed by the need to address the decrease of European gas production, the increasing consumption and flexibility requirements, and the opportunity to exploit price volatility of the new liberalised markets (European Commission, 2015). Gas storage can play an important role in providing flexibility and security of gas supplies. Depending on their design and characteristics, UGS can secure supplies in times of high demand and high prices by providing seasonal flexibility and cheaper gas. It can also facilitate the proper functioning of the gas market by providing short term flexibility. In the future, as shares of renewables in the electricity generation mix increase the role of gas as flexible back-up fuel in promoting the security of gas supply may be further enhanced with the help of flexible storage facilities.

In this section an overview of the UGS facilities in the EU is provided. The full list and main characteristics of the EU UGS facilities are compiled in Table A1 of Annex 1. There are 19 European Member States that hold underground storage capacity. From Figure 3 it is possible to infer that the total storage capacity of UGS facilities in the European Union is currently 1277 TWh and that the largest capacities belong to Germany, Italy, Austria and France, with around 50% of total capacity concentrated in Germany, Italy and France. The same three countries have the highest concentration of storage sites, and together account for 57% of the total number of underground storage facilities in Europe (see Table A1 of Annex 1).

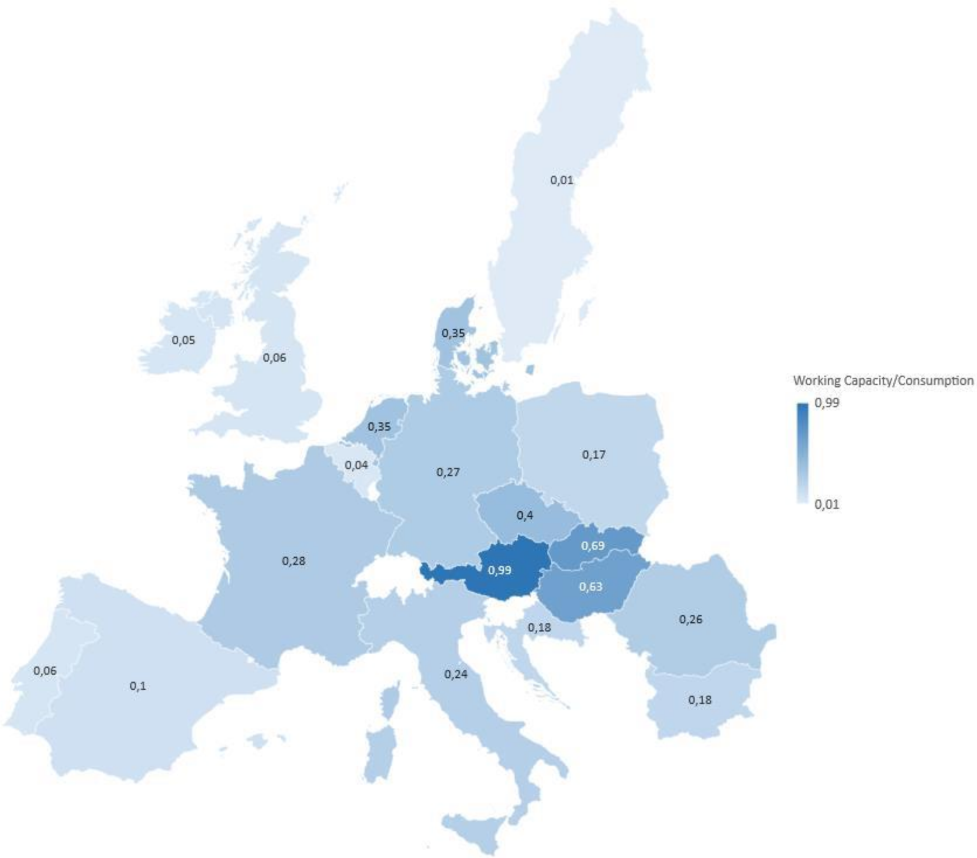
Figure 4 shows the ratio between the working capacity of underground gas storage facilities and the gas consumption in European countries. The undoubted leader in this case is Austria, which can store almost all its annual consumption. A significant part of the annual consumption can also be stored in Hungary and Slovakia. In the opposite site they are found Finland, the Netherlands, Ireland, UK and Portugal, which ration working capacity/consumption is close to zero.

Figure 3. Distribution of the volume of working gas in EU UGS facilities by country



Source: JRC figure based on data from Gas Storage Europe, 2018.

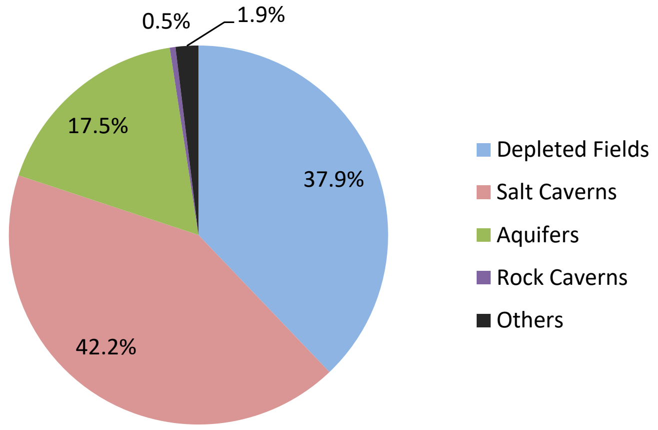
Figure 4. Working capacity/consumption ratio in Europe.



Source: Gas Storage Europe data, Eurostat data (Stopa, J., 2018).

Underground storage sites can be categorised in three main types: salt caverns, depleted fields and aquifers. Salt caverns are the most common UGS facilities in EU, followed by depleted fields (see Figure 5). As it was explained in section 3.1, salt caverns have the highest injection and withdrawal rates, and these are concentrated in Germany, France, UK, Netherlands, Poland and Portugal.

Figure 5. Breakdown of operational UGS facilities in Europe by type



Source: JRC figure based on data from Gas Storage Europe, 2018.

3.5 Main Failure Modes

Underground storage is the safest way to store large quantities of hydrocarbons. Deep formations are almost perfectly impermeable and underground, hydrocarbons are separated from the oxygen in the air by several hundred meters of rock. This same natural barrier protects them from fire, wilful damage and aircraft impact. The fact that gas is stored underground at high pressure does not present any problem insofar as high pressure is the natural state of the fluids underground. However, hydrocarbons are valuable because they release large quantities of energy when they burn or explode, making them hazardous to transport or store.

A thorough review of incidents relating to UGS has been carried out by British Geological Survey (Evans, 2007). The report encounters overall 64 examples of problems at UGS facilities (82% of them have occurred in America). Of these, 27 have been at salt cavern facilities, 16 at aquifers and 16 at depleted oil/gas fields. The 64 incidents have been of varying cause, severity and nature, with some involving only minor problems that were quickly rectified and at not stage threatened failure of the facility or release of product. However, in four of these incidents a total of 8 deaths have been found reported in the literature as a result of the release of the stored product, all involving storage in salt cavern facilities. Incidents have been categorised according to their cause.

Incidents resulting from failure of the storage cavity in depleted oil/gas fields are a type of failure considered as a geological failure and involve the migration of the gas out of the original cavity through either rock mass discontinuities or faults. The majority of the documented problems in depleted oil and gas fields have been reported in the USA, specifically in California, which it has particular geological factors that would not necessarily be applicable or relevant to assessment of UGS in the Europe situation.

Incidents resulting from failure of the storage cavity in salt caverns involve the migration of gas away from the original storage area or no release of gas at all. However, the consequence in both cases implies that the capacity of the cavity changes and there is the potential for an incident to occur if the problem is not detected, for instance overfilling if the reduced capacity is not identified.

Incidents resulting from well failure involve releases through failed or leaky boreholes, casing failure and well valve failure. Usually this failure leads to failure of the pipework connecting the storage cavity to the surface.

Table 1. Summary of overall incidents in UGS reported by type of facility.

Cause	Depleted oil/gas incidents	Salt cavern incidents	Aquifer incidents	Others
Failure of the storage cavity	6	7		
Well failures	5	11		
Above ground infrastructure	3	7		
Unknown	2	2	16	5
TOTAL number of incidents	16	27	16	5

Source: British Geological Survey report (Evans, 2007).

Although many of the incidents have occurred in the US and very few failures have been reported in Europe, a working group was set up in 1998 by Marcogaz[1] to exchange information on European UGS operations. Eight European companies participated and an accident database was established. The eight companies taking part in the study owned 42 sites in total which corresponds to 845 wells. The study concluded that:

- 6 accidents occurred due to surface processes over a cumulative period of 970 years and the calculated probability for major accidents on surface facilities of UGS sites was 6x10-3 accident/year/site.
- 5 accidents occurred due to faulty wells over a cumulative period of 100 155 years and the calculated probability for major accidents on wells of UGS sites was 5x10-5 accident/year/site.
- 1 accident occurred that resulted in severe injury due to well problems over a cumulative period of 100 155 years and the calculated probability of major accidents resulting in severe injury on wells was $1x10^{-5}$ accident/year/site.

From the Marcogaz study, HSE (HSE, 2008) used different methodologies to estimate operating experience for different UGS types in order to estimate failure rates according not only to the cause of the failure but also to its type. The different types of failure of the UGS system were calculated using the incidents described in Table 1 and the operating experience estimated in the HSE report (HSE 2008). Calculated failure rates are compiled in Table 2 according to facility types and failure causes. The HSE report states that these failure rates are likely to be pessimistic since they try to extrapolate accident data from the US, where higher numbers of incidents associated to geological factors are not necessarily applicable or relevant to the situation in Europe.

Table 2. Summary of calculated failure rates by type of facility and failure scenario.

Failure Rate	Depleted oil/gas fields (Europe)	Salt caverns (Europe)	Depleted oil/gas fields (worldwide)	Salt caverns (worldwide)
Failure of the storage cavity (per well year)	1.2×10^{-5}	4.1×10^{-5}	9.9×10^{-6}	3.4×10^{-5}
Well failures (per well year)	1.2×10^{-5}	4.1×10^{-5}	8.3×10^{-6}	1.7×10^{-4}

Source: Failure rates for underground gas storage, (HSE report, 2008).

[1] Technical Association of the European Natural Gas Industry

4 LNG terminals

4.1 Types of LNG terminals

One of the main steps in the LNG process chain involves the import terminals. These are marine or waterfront facilities where the LNG is delivered by sea vessels, regasified and sometimes stored before being injected into the distribution system. LNG regasification terminal layouts can be classified under four categories (iNTeg-Risk project 2011a):

- On-shore
- Off-shore gravity based structure (GBS)
- Off-shore floating storage and regasification unit (FSRU)
- Off-shore transport and regasification vessel (TRV)

The most common and developed layout type is currently the **on-shore** LNG facility. This layout consists of a plant build nearby the sea, usually within a harbour area. It typically consists of a docking area, provided with a jetty and loading/unloading arms and a standard boil-off gas (BOG) handling and recovery section. This concept of regasification terminal has been developed decades ago. Some of the facilities in this category have been built as early as the 60s (for instance, the Panigaglia terminal in Italy was built in 1967).

From a structural point of view, offshore LNG terminals can be fixed (e.g. sea island jetty or jacket) or floating (e.g. floating wharf and weather vanning). The selected support technology is crucial since it has a large impact on investment and operating costs, flexibility, safety, availability and reliability, time for completion, etc. While offshore LNG regasification systems may appear to offer many advantages over onshore systems, they also introduce new challenges, risks, and uncertainties into the LNG supply chain. Whereas offshore oil platforms have a long track record, the concept of offshore LNG regasification is quite new and thus has new considerations in terms of environmental issues, floating operations and floating LNG offloading. There are many considerations for siting offshore LNG regasification terminals, including shallow water or deep-water locations, coastal or deep offshore locations. Final designs depend on distance from shore, marine environment, type of soil, pipeline availability, and market area (Bulte 2017).

An innovative layout for LNG regasification purposes is the **off-shore gravity based structure (GBS)** regasification terminal. The design is typically developed around a large concrete structure, which houses modular self-supporting storage tanks, specifically designed for this layout type. Offshore concrete structures for the production of oil and gas are well established and proven in the North Sea and other areas, with developments started more than 40 years ago. Such structures have demonstrated excellent performance in a hostile marine environment with an absolute minimum of maintenance (Haug, Eie et al. 2003). In 2009 the offshore terminal of Porto Viro, in Porto Levante near Rovigo in Italy, was the first LNG regasification facility of this type in the world to be inaugurated.

A **floating storage and regasification unit (FSRU)** is a solution consisting of a vessel, new or reconverted from a carrier, equipped with tanks for LNG storage and with all the required vaporization process equipment (Bulte 2017). The FRSU's main components are: LNG transfer system (offloading system); Storage tanks, (in ship); Boil-off gas handling system; LNG pumping system; Vaporization equipment; Delivery facility; and Auxiliary systems. In the FSRU, the LNG delivered by LNG carriers is received by the FSRU offloading system, stored in tanks, pumped, regasified into natural gas and delivered to consumers through a flexible or rigid riser, connected to the subsea pipeline or via high-pressure loading arms fixed on a jetty. Prior to its delivery, the natural gas flow rate is measured and the gas is odorized. (Songhurst 2017) outlines the development of this type of structure over the past 16 years, describing the physical processes involved, the capital and operating cost parameters and the key benefits of using an FSRU vessel. This author also describes the main players in the industry, the contractual models that have been developed and reports a full listing of all the current vessels in operation, as well as those under construction, thus providing a comprehensive overview of the state of the market as of mid-2017.

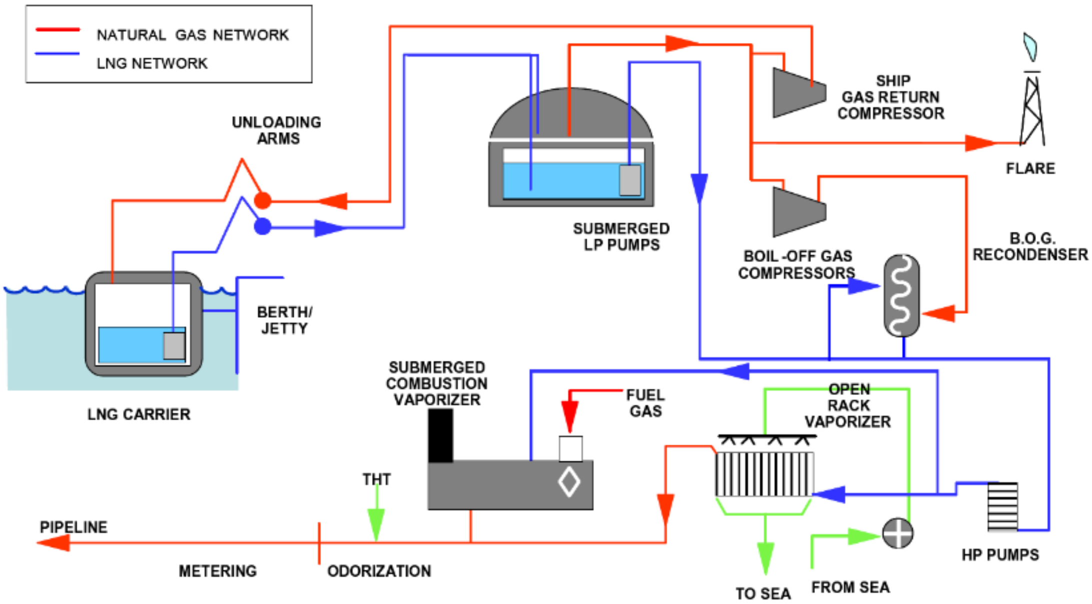
Off-shore TRV regasification terminals are similar to the FSRU typology in many features. They make us of an LNG carrier (and are hence not affected by sea depth) but are not permanently moored to the seabed, thus maintaining their own capability to transport LNG).

4.2 Operation of LNG terminals

A typical on-shore LNG import terminal process flow diagram is shown in Figure 6, whereas Figure 7 depicts the flow diagram for a FSRU. The major equipment components of an LNG import and regasification terminal are:

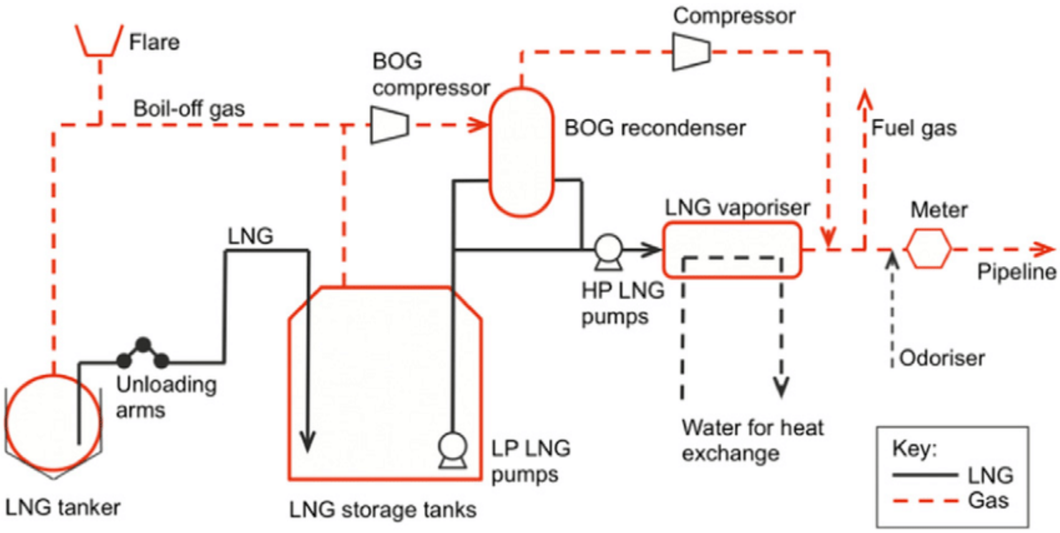
- Unloading arms;
- Cryogenic pipelines;
- Storage tank(s);
- Low pressure pumps;
- Boil-Off Gas (BOG) compressors and re-condensers;
- High pressure (HP) pumps;
- Vaporisers.

Figure 6. Example of an onshore LNG import terminal flow scheme.



Source: International Group of Liquified Natural Gas Importers, 2014.

Figure 7. Example of a FSRU flow scheme



Source: Khan, 2018.

LNG unloading operations use articulated arms which are specifically designed to transfer cargo safely from the ship's manifold system to the terminal. Once the LNG carrier is moored, loading arms are gradually chilled to -162°C (-259°F) prior to the beginning of LNG unloading operations. The unloading arms are able to endure the expansion and contraction resulting from changes in temperature. A risk during unloading is the potential extension and rupture of unloading arms due to ship movements. Consequently, these arms are equipped with emergency disconnect systems. To protect both the ship's manifold connection and the terminal's arms, a Power Emergency Release Coupler is typically fitted into most arm installations. This system, comprised of two ball valves and an emergency release coupler, allows the rapid disconnection of the LNG carrier from the terminal while limiting the amount of LNG released. Position detectors check that the ship is not shifting too quickly in a manner likely to damage the connecting arms. These detectors can activate the emergency disconnection system. If the vessel moves outside the normal operating range for the connecting arms, an emergency shutdown device is automatically activated and LNG transfer is halted. Further movement of the vessel outside of the operating range will activate the emergency release system. The ball valves will close and the emergency release coupler will operate. One ball valve remains attached to the ship and the other stays attached to the hard arm. The release system may also be manually activated by an operator.

After unloading, LNG is transferred via cryogenic pipelines to insulated storage tanks specifically built to hold LNG. LNG storage tanks are designed to withstand cryogenic temperatures, maintain the liquid at low temperature, and minimize the amount of LNG escaping. The small part of LNG that evaporates is called boil-off gas (BOG). Boil-off gas is the vapour produced above the surface of a boiling cargo due to evaporation, typically caused by heat or a pressure drop. The temperature within the tank will remain constant if the pressure is kept constant by allowing the boil-off gas to escape from the tank. This gas is captured and is either re-condensed or re-injected into the LNG carrier to maintain positive pressure during the unloading of the ship. In abnormal or accidental situations, the BOG can be sent to the flare to be safely dispersed.

The storage facility is designed with a venting feature as an ultimate protection against risk of overpressure due to a "roll-over" condition in the LNG tank. LNG "rollover" refers to the rapid release of LNG vapours from a storage tank, resulting from stratification. The potential for rollover arises when two stratified layers of different densities (due to different LNG compositions) exist in a tank. To prevent rollover, special instruments (densitometers) are used to monitor the development of the layers within the tank, thereby allowing the operator to mix the LNG (either within the tank or with LNG from a different tank) to dissolve the stratification. An import terminal usually has two or more LNG storage tanks. The types of tank types are as follows:

- Single containment tanks;
- Double containment tanks;
- Full containment tanks;

- Membrane tanks;
- In-ground tanks.

The LNG stored in the tanks is eventually sent to vaporisers, which warm and regasify the liquefied gas. The main types of vaporisers used in the LNG industry are:

- Open Rack Vaporisers;
- Submerged Combustion Vaporisers;
- Intermediate Fluid Vaporisers;
- Ambient Air Vaporisers.

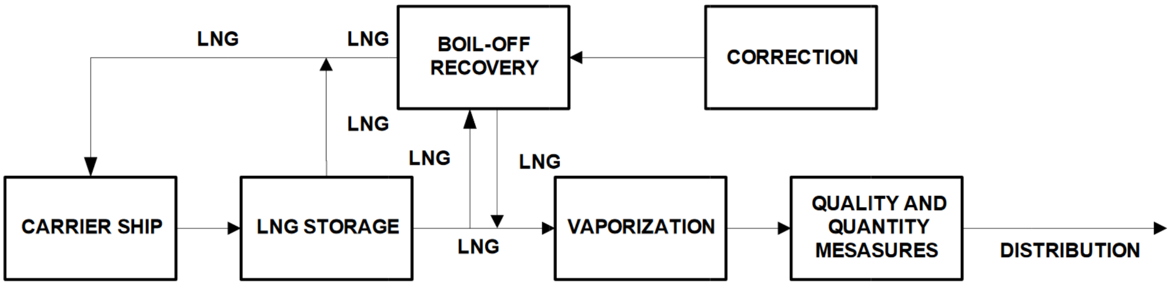
Open Rack Vaporisers derive the heat necessary to vaporise LNG from seawater. The water is first filtered to avoid the presence of small solid particles in the ORV. It then falls onto panels of tubes containing LNG and then gathers in a trough underneath before being discharged back into the sea. The LNG passing through the tubes is heated and vaporises. The tubes are specifically designed to optimise heat exchange. *Submerged Combustion Vaporisers* burn natural gas produced by the terminal and pass the hot gases into a water bath containing a tubular heat exchanger where LNG flows. The froth produced by the combustion gas increases the efficiency of heat transfer between the water and the LNG, and prevents ice from forming on the tube bundle. This type of vaporisers typically uses 1.2 to 1.5 % of the natural gas processed. *Intermediate Fluid Vaporisers* rely upon two levels of thermal exchange: the first is between LNG and an intermediate fluid such as propane, and the second is between the intermediate fluid and a heat source, usually seawater. The surface area of the exchangers is designed to optimise the heat exchange. Intermediate fluid vaporisers prevent freeze-up and reduce fouling risks. This particular operational benefit can justify the increased cost that arises from the use of an intermediate fluid. *Ambient Air Vaporisers* use the heat from the air. It is a proven technology and has generally been used for smaller installations such as LNG satellite terminals fed with LNG by road truck. The units may have natural convection of fan-assisted airflow. Some larger units have recently been installed at LNG import terminals where seawater systems are considered unsuitable.

Before natural gas is distributed to consumers, a slightly unpleasant-smelling odour is added. A typical odorant is THT (tetrahydrothiophene) or mercaptan. Because natural gas is colourless and odourless, a leak is impossible to detect without appropriate instruments. To make the detection of a gas leak easier, whether it is in our kitchen or in a pipeline, an odorant is normally added to natural gas. The odorisation station can be in the LNG terminal itself before the send-out of natural gas, or just a few kilometres beyond the terminal. The point at which odorants are added depends on the country. Many terminals that export to a high-pressure transmission line do not odorise. Metering, the last step at the terminal, measures the quantity of gas which is being sent out. Natural gas is then delivered by pipeline directly to customers for industrial or residential use.

In conclusion, Figure 8 reports the typical schematic of the LNG regasification process.

1) At the terminal, LNG is offloaded from the carrier and is transferred to storage tanks.
2) In some configurations (e.g. TRV terminals) there is no LNG storage and LNG is vaporized on-board and offloaded as compressed natural gas by a sea line. In the other cases, LNG is transferred via the unloading arms from the moored carrier to the LNG storage tanks by cryogenic pipelines.
3) The pressure in the LNG storages of the carrier during unloading operations is maintained constant by a back flow of NG vapour from the storage tanks to the carrier.
4) In the vaporization stage, LNG is compressed to the desired final delivery pressure and vaporized by dedicated heat exchangers (vaporizers). Alternative configurations use different heat sources (hot combustion gases, seawater, ambient air, waste heat, etc.) and different heating media (propane, water, water/glycol mixtures, air, etc.).
5) In the correction and measurement sections of the process, the quality of the gas is brought to the specification of the national grid. The correction usually consists in introducing dosed quantities of air or nitrogen-enriched air in the natural gas.

Figure 8. Scheme of the LNG regasification process



Source: Vianello and Maschio, 2014.

4.3 An overview of LNG regasification terminals in EU

The following account is largely based on the thorough report by (King & Spalding 2018) and by information reported by Gas Infrastructure Europe, see for instance (Gas Infrastructure Europe 2019a) and (Gas Infrastructure Europe 2019b). Annex 2 reports tables that summarise the most essential information for large and small LNG terminals, including operational as well as planned facilities. Table 3 below summarises the annual regasification capacity of LNG large scale import terminal of EU countries.

Table 3. Annual regasification capacity of LNG large scale import terminal per country (bcm/year).

COUNTRY	Operational	Under construction	Suspended	Planned
Belgium	9			
Croatia		3		
Cyprus				2
Estonia				7
France	34			11
Germany				26
Greece	7			6
Ireland				14
Italy	15			8
Latvia				5
Lithuania	4			
Malta	1			
Netherlands	12			4
Poland	5	3		8
Portugal	8			
Spain	69	3		4
United Kingdom	48		4	13
EU 28	**212**	**9**	**4**	**108**

Source: (Gas Infrastructure Europe 2019b).

4.3.1 Belgium

Belgium is a major hub for gas supply in Europe, with some 80 bcm transiting the country each year, compared with domestic consumption of just over 17 bcm/year. It has a robust transport network that is well integrated with other countries through 18 entry points. Belgium does not produce any natural gas and relies entirely on imports to supply its gas needs. In 2017 Belgium imported 1.11 bcm of LNG (net of re-exports) – an increase of 11.7% from 2016 – and was Europe's ninth largest importer of LNG. Gas imports into Belgium are fairly diversified by origin and type of supply: the Netherlands and Norway are the principal pipeline suppliers, each providing about a third of total gas imports. The Zeepipe, which brings piped gas from Norway, and the Interconnector gas pipeline between Belgium and the UK, both land at Zeebrugge. LNG is imported into Belgium through a single LNG terminal, Zeebrugge.

Zeebrugge Terminal. The Zeebrugge LNG terminal is located along the northern part of the Belgian coastline and is built on a man-made island. It is owned and operated by Fluxys LNG SA. The terminal came into operation in 1987, initially having a single jetty, three storage tanks and send-out facilities. Between 2004 and 2007 the terminal was expanded to include a fourth storage tank and increased send-out capacity. Testing and commissioning of a second jetty were completed at Zeebrugge at the end of 2016. LNG unloaded at the terminal can be regasified to be traded or consumed as natural gas within Belgium, or supplied to other end consumer markets in any direction (the UK, the Netherlands, Germany, Luxembourg, France and Southern Europe), or traded on the Zeebrugge hub. The Zeebrugge LNG terminal is increasingly active in small-scale LNG. LNG loading services started at the terminal in 2008 and LNG truck loading in 2010. Since January 2015, smaller ships have been loaded to supply remote industrial end users and to supply LNG as a fuel for ships and trucks. At present, the majority of LNG used as a fuel for shipping and road haulage in northwestern Europe is loaded at Zeebrugge.

4.3.2 Croatia

Krk LNG Terminal. The floating LNG terminal is located in Omišalj municipality on the island of Krk, in the Republic of Croatia It is a 2.6 billion cubic metres per year (bcm/y) floating LNG regasification and import terminal project near completion. The terminal was developed and will be operated by LNG Croatia, a joint venture of two Croatian state-owned companies. Hrvatska Elektroprivreda, the state-owned gas and electricity utility, holds 85% interest in LNG Croatia, while the remaining 15% is held by Croatia's gas transmission system operator Plinacro. The final investment decision on the €233.6 million project was reached in January 2019, while construction works were started in April 2019. The terminal will start operations in 1 January 2021 and all free terminal capacity has already been booked for the next 3 years (2021-2023).

4.3.3 France

France produces about 1% of the gas it consumes, and almost all gas consumed in France is imported. In 2017, France imported 9.3 bcm of LNG and was Europe's third largest importer of LNG after Spain and Turkey). France's total natural gas imports are relatively well diversified, with significant imports from Norway, the Netherlands, Russia and Algeria. About 72% of the entry capacity to the French gas network is for cross-border gas pipelines, and the remaining entry capacity (about 28%) is for gas from France's four existing LNG import terminals. Algeria is the main source of supply of LNG to France. France has four operational large-scale onshore LNG import terminals: Fos Cavaou and Fos Tonkin near Marseille, Montoir-de-Bretagne on the Atlantic coast, and Dunkerque in north-west France.

Fos Cavaou Terminal. The Fos Cavaou LNG terminal opened in 2010 and is located on France's south coast along the main LNG transport routes, where it can easily receive gas from countries such as Egypt, Algeria and the Middle East. Its regasification capacity of 8.25 bcm/year is equivalent to about one-sixth of France's annual gas consumption. 90% of the terminal's capacity is subscribed for on a long-term basis, and the remaining 10% of capacity is available for subscription on the basis of short-term contracts. The terminal offers truck loading services and plans to increase the load to up to 20 trucks by 2019. The terminal will offer LNG bunkering from 2019. The Fos Cavaou terminal has offered reloading services since 2012. It has also offered a transshipment service since December 2015.

Fos Tonkin Terminal. The Fos Tonkin terminal, located 50 km west of Marseille, started operations in 1972, and was one of the first LNG terminals in Europe. The terminal has send-out capacity of 3.4 bcm/year – which has been reduced to 3 bcm/year since April 2015. Since June 2015 the Fos Tonkin terminal has offered LNG truck loading services for up to 4 trucks a day, increased to 8 trucks per day from July 2016 and 11 trucks per day from 2017.

Montoir-De-Bretagne Terminal. The Montoir-de-Bretagne LNG terminal is located on France's Atlantic coast and was commissioned in 1980. Until 2005 it was the largest import terminal in Europe with a regasification capacity of 10 bcm/year. It has a storage capacity of 360,000 m3 and handles around 100 tanker shipments a year. Since 2013 the terminal has been active in ship-to-ship transfers. The terminal has provided LNG truck loading services, and since September 2017 the terminal has been able to load 18 LNG trucks each day. Like Fos Tonkin, the Montoir-de-Bretagne terminal is considering the introduction of rail loading services as a railway is available.

Dunkerque Terminal. The Dunkerque LNG terminal came into commercial operation at the end of September 2016. The terminal has a jetty large enough to enable the unloading/reloading of the largest LNG carriers and three storage tanks, each capable of storing 190,000 m3 of LNG. The terminal is connected to both the French and Belgian gas distribution networks, and is capable of meeting about 20% of the two countries' annual gas demand. This link between Dunkerque and the Zeebrugge area contributes to the diversification of supply sources in North West Europe. The terminal offers regasification, reloading, loading of bunkering ships and truck loading services.

4.3.4 Greece

Greece produces only a small amount of gas, and demand for natural gas is steadily increasing. In 2017 Greece imported 1.62 bcm of LNG and was Europe's seventh largest importer of LNG. Between 2014 and 2017 there was a 68% increase in gas consumption in Greece, with a 21% increase in 2017 compared with 2016. Natural gas accounts for approximately 14% of Greece's total primary energy supply, of which approximately one-quarter is LNG which is imported into Greece's only LNG terminal at Revithoussa. The remaining part is imported from Russia by pipeline.

Revithoussa Terminal. The Revithoussa LNG terminal is located on the islet of Revithoussa, west of Athens. It came into operation in 2000 and today has a capacity of 7 bcm/year. The combined storage capacity of its two LNG tanks is 130,000 m3. The second expansion project at Revithoussa – the construction of a third tank of 95,000 m3, and facilities for reloading small and medium-sized ships – commenced in May 2014 and was expected to be completed in 2017; however, the expansion project is ongoing. The terminal currently offers regasification and truck loading services. Reloading services are being considered, with a target date of end 2018, and loading of bunkering ships is also under consideration for vessels as small as 1,000 m3.

4.3.5 Italy

Although Italy produces significant volumes of indigenous gas, it is one of Europe's largest gas consumers at around 78 bcm/year and imports about 90% of the gas it consumes. In 2017 Italy imported 7.55 bcm of LNG and was Europe's fourth largest importer of LNG. 60% of Italy's imported natural gas is made up by just two countries: Algeria and Russia. Significant sources of imports are also Libya, Qatar, the Netherlands and Norway. Most of the country's gas is imported by pipeline. LNG, which is imported into Italy's three existing operational LNG import terminals at La Spezia (Panigaglia), Porto Levante and Toscana (offshore), until 2014 accounted for only around 11% of the total volume of gas imported into the country. In 2015, however, LNG imports to Italy increased by almost 32% to around 4.3 bcm, largely due to supply from Qatar to the Adriatic LNG terminal (at Porto Levante). 2017 saw a further increase of 32% of LNG imports to Italy, representing 15% of the EU's total LNG imports that year. Italy is planning three additional LNG import terminals: the Falconara Marittima (an FSRU), and two large-scale onshore terminals – Porto Empedocle in Sicily and Gioia Tauro LNG in Calabria.

Panigaglia Terminal. The Panigaglia LNG import terminal, located in the municipality of Porto Venere in the western part of the Gulf of La Spezia, started operations in 1971 and is one of the oldest LNG import terminals in Europe. It currently has a capacity of 3.4 bcm/year, although an expansion is planned which includes increasing the terminal's send-out capacity to 8 bcm/year, storage capacity to 240,000 m3, the capability to unload ships of up to 140,000 m3, an update to the terminal's storage tanks and equipment, and installation of a 32 MW cogeneration plant for the production of gas-fired electricity.

Isola Di Porto Levante LNG Terminal. The Isola di Porto Levante (Rovigo) LNG terminal (also known as "Adriatic LNG") is located in the northern Adriatic, 14 km offshore of Porto Viro, in Porto Levante, near Rovigo. The terminal received its first cargo of LNG in August 2009 and was officially inaugurated in October 2009. The Porto Levante terminal is the first ever offshore Gravity Based structure (GBS) for the unloading, storage and regasification of LNG. The terminal has a regasification capacity of 8 bcm/year, which accounts for approximately 10% of Italy's natural gas requirements.

FSRU OLT Offshore LNG Toscana. The OLT Offshore LNG Toscana project converted the Golar Frost LNG carrier into a floating storage and regasification unit, which is permanently anchored about 22 km off the Italian coast between Livorno and Pisa. The terminal became fully operational on 20 December 2013. The Toscana LNG terminal's regasification capacity is 3.75 bcm/year, which is around 4% of Italy's gas requirements. Its storage capacity is 135,000 m3.

4.3.6 Lithuania

Lithuania has no domestic gas production, and has historically relied on Russia for 100% of its gas supply. In 2017 Lithuania imported 1.10 bcm of LNG and was Europe's tenth largest importer of LNG. In December 2014 the first commercial cargo of LNG was delivered at Lithuania's first LNG import terminal (FSRU Klaipeda LNG) marking the start of the country's diversification of gas supply. In its first full operational year (2015) the Klaipeda LNG terminal operated primarily as a political tool to ensure security of supply to countries that traditionally have relied on imported gas from Russia, and imported only 0.32 bcm of LNG. In 2016, however, the terminal established its commercial viability. In the first three quarters of 2016 imports increased significantly, with an average utilisation rate of 40% compared with 14% in 2015. However, in 2017 LNG imports declined to 0.85 bcm of LNG, a 13.4% drop compared with 2016.

Klaipeda LNG FSRU Terminal. The Klaipeda LNG FSRU is situated in the port of Klaipeda, Lithuania. The new-build FSRU vessel "Independence" was developed by Hyundai Heavy Industries. It is 294 metres long, 46 metres wide and 47 metres high. It has four storage tanks with a total capacity of 170,000 m3, and has a send-out capacity of 4 bcm/year. The terminal now offers LNG bunkering services through new small-scale LNG facilities. From 2018 the terminal's operator, Klaipedos Nafta, expects small-scale capacity holders using the terminal to bolster utilisation rates. The terminal has amended its regasification and capacity rights to accommodate small-scale users.

4.3.7 Malta

Malta has no domestic production of oil or gas and no gas distribution network. In 2017 Malta become Europe's latest importer of LNG. In its first year Malta imported 0.32 bcm. Recently, Malta has been dependent on heavy oil as its main source of energy production but in 2013, an initiative was launched to introduce LNG supply to Malta for power generation. The project, which was completed in 2017, comprises an FSU, the Armada LNG Mediterrana; onshore regasification facilities; and the construction of a combined cycle gas turbine plant, Delimara 4, alongside the existing Delimara 3. At the beginning of 2017, Malta received its first ever shipment of LNG at the Delimara terminal.

Delimara LNG Terminal. The Delimara LNG terminal is located in Marsaxlokk, in the south-eastern region of Malta. It consists of an FSU and an onshore regasification facility. Its main purpose is to supply regasified natural gas to both the Delimara 4 CCGT (215 MW) and the Delimara 3 (149 MW) power plants, via a connecting gas pipeline. The Delimara FSU, Armada LNG Mediterrana, was originally built in 1985 and has a capacity of 125,000 m3 The FSU was converted from the former LNG carrier Wakabu Mar and is permanently moored by jetty near the Delimara Power Station.

4.3.8 The Netherlands

The Netherlands is the biggest producer of gas in the EU, but domestic supply is decreasing. In 2017 the Netherlands imported 0.98 bcm of LNG and was Europe's eleventh largest importer of LNG. The Groningen gas field in the north-eastern part of the Netherlands is the largest natural gas field in Europe and the tenth largest in the world. Recently it has accounted for approximately 50% of natural gas production in the Netherlands and has been projected to last for another 50 years. However, in response to earthquakes in the region, the Dutch government has capped production for the foreseeable future, and Dutch gas production is forecast to decline significantly by 2020. In 2017 the Netherlands became a net importer of gas. LNG is imported into the Netherlands' only LNG import terminal, the Gate terminal, in the Port of Rotterdam.

Gate terminal. The Gate (Gas Access to Europe) terminal was officially opened in September 2011. It is located on the Maasvlakte in Rotterdam, and consists of three storage tanks, three jetties and a regasification process area. The terminal was developed to address the rising demand for gas in North West Europe due to declining gas production in that region. It has an initial capacity of 12 bcm/year (with the potential of being increased to 16 bcm/year with the addition of a fourth LNG tank) and delivers gas into the Dutch gas transport network. Since August 2016 the Gate terminal has operated a third berth and specialised new infrastructure for the loading of small LNG vessels, which strengthens Gate's role as a hub terminal in North West Europe. The terminal added two truck loading facilities in 2017.

4.3.9 Poland

Although Poland has significant (but declining) domestic gas production, it is a net importer of gas – primarily from Russia. In 2017 Poland imported 1.61 bcm of LNG and was Europe's seventh largest importer of LNG. Poland remains heavily dependent on coal as a primary energy source, and the vast majority of electricity generation in Poland is coal-based. Poland is seeking to diversify its energy mix, with natural gas and other energy sources becoming a strategic priority. Natural gas is the third most important energy source consumed in Poland after coal and crude oil, accounting for approximately 14% of consumption. The first commercial cargo of LNG was delivered to Poland's only LNG import terminal, the Swinoujscie terminal, in July 2016.

Swinoujscie Terminal. The Swinoujscie LNG terminal is Poland's flagship project to diversify gas supplies and reduce dependence on gas pipeline imports from Russia. The terminal is able to receive, regasify and deliver 5 bcm of gas per annum into the Polish national grid. It consists of a 3 km long breakwater, a jetty that is able to unload carriers with the capacity ranging from 120,000 m3 to 217,000 m3, two 160,000 m3 LNG storage tanks and regasification facilities.

4.3.10 Portugal

Portugal does not produce any natural gas and is wholly dependent on imports for its gas requirements (about 4 bcm/year). In 2017 Portugal imported 3.4 bcm of LNG and was Europe's sixth largest importer of LNG. Natural gas is imported into Portugal via the Maghreb-Europe Gas Pipeline from Algeria and Portugal's only LNG terminal, Sines LNG. In 2015 net LNG imports to Portugal grew to 1.12 bcm, representing a 16.2% increase from 2014. In 2017 Portugal imported 2.71 bcm of LNG, marking an increase of 107.3 % in comparison with 2016.

Sines Terminal. The Sines LNG terminal is located on Portugal's Atlantic coast, in the Sines port about 120 km to the south of Lisbon. The terminal started operations on 26 October 2003 and consists of a docking station for ships with capacity from 40,000 m3 to 216,000 m3, three storage tanks with a combined capacity of 390,000 m3 and seven open-rack vaporisers for LNG regasification. More than 230 LNG carriers have called at the facility since operations began, with the majority supplying LNG from Nigeria.

4.3.11 Spain

Spain has one of the highest levels of natural gas consumption in Europe but only produces less than 0.5% of the gas it consumes. This makes Spain Europe's largest importer of LNG. In 2017 it imported 15.39 bcm of LNG. With six LNG import terminals currently in operation, Spain has more regasification capacity than any other European country. A seventh terminal, El Musel, has been in hibernation since it was completed in 2013. Spain's six operating LNG terminals have a regasification capacity of 60 bcm/year. New LNG import terminals on the Spanish islands of Tenerife and Gran Canaria will come into operation in 2021 and 2022, respectively. Both terminals will have a nominal capacity of 1.3 bcm/ year, with plans to increase capacity to 2 bcm/year in the future.

Barcelona LNG Terminal. The Barcelona terminal is the oldest regasification terminal in Spain, beginning operations in 1969. The initial facilities consisted of two storage tanks with a combined capacity of 80,000 m3, but several additions have been carried out throughout the years, with an eighth tank been added in 2011. The terminal's send-out capacity stands now at 17.1 bcm/year. Since December 2010 the terminal can receive LNG vessels of up to 266,000 m3. It provides truck loading services for up to 50 trucks a day and the loading of bunkering of ships services are being developed.

Cartagena LNG Terminal. The Cartagena LNG terminal is located in southern Spain. It started operation in 1989 and originally consisted of a single storage tank, send-out facilities and a single container berth of 40,000 m3. Storage tanks were added and in October 2010 a fifth tank of 150,000 m3 entered into operation. The send-out capacity currently stands at 11.8 bcm/year. Since 2009 the terminal has been capable of receiving vessels of up to 266,000 m3. The capability of loading bunkering ships was completed in mid-2017. The terminal can also offer LNG truck loading for up to 50 trucks a days, as well as trans-shipment services for small and large vessels.

Huelva LNG Terminal. The Huelva LNG plant is located in Andalusia. It began operations in 1988 and had initially a single storage tank with a capacity of 60,000 m3. The terminal underwent its first expansion when the Seville-Madrid gas network pipeline was built, and subsequent expansions were carried out to bring the terminal's storage capacity up to 619,500 m3 and its send-out capacity up to 11.8 bcm/year. The terminal is capable of receiving ships with a capacity of up to 173,400 m3. The terminal offers ship loading and cooling down and gassing up services for ships between 29,500 m3 and 173,400 m3 as well as truck loading services for approximately 50 trucks per day. Loading of bunkering ships is being considered.

Bilbao Bahía De Bizkaia Terminal. The Bahía de Bizkaia LNG terminal is located near Bilbao. It began operations in 2003 and underwent an expansion in 2015 with the addition of a third 150,000 m3 tank, which increased the terminal's storage capacity to 450,000 m3. The terminal supplies gas for commercial consumption but also for producing electricity in nearby Bahía de Bizkaia Electricidad (BBE) 800 MW combined cycle electric power plant. Since November 2015 the terminal has provided truck loading services. The terminal completed the adaption of its jetty, which is now compatible with large-scale and small-scale reloading/bunkering operations.

Sagunto Terminal. The Sagunto terminal is located nearby Valencia. Its location is ideal for both the LNG-producing countries of North Africa and the Persian Gulf and the energy consumers in the Mediterranean. It began operations in February 2006 and initially comprised a jetty, a regasification facility and two 150,000 m3 storage tanks. The terminal currently consists of four 150,000 m3 storage tanks, six vaporisers and all the infrastructure required for unloading methane tankers, storage, regasification of LNG and consignment of natural gas to the network, as well as a tanker-truck loading facility. The terminal satisfies up to 25% of the gas demand throughout Spain. Since 2011 the terminal has offered truck loading services, and since 2013 it has offered ship reloading.

Mugardos (El Ferrol) Terminal. The Mugardos LNG terminal is located on the north-western coast of Spain in the Galicia region. The terminal received its first cargo in May 2007 and went into operation in November of that year, becoming Spain's sixth receiving LNG terminal. The majority of the gas generated at the terminal is consumed by gas-fired power plants located nearby. There are plans to add two more 150,000 m3 storage tanks and to increase capacity to 7.2 bcm/year over the next ten years.

El Musel Terminal. El Musel terminal is located in Gijon, on the northern coast of Spain. The plant was completed in 2013 but was immediately mothballed, and under Spain's Royal Decree 13/2012, El Musel will remain in "hibernation" until gas demand rises. The site was designed for expansion, with plans to install an additional two tanks in the second phase of the project, taking total storage capacity up to 600,000 m^3.

4.3.12 United Kingdom

The UK is one of the two major gas-producing nations in the EU (the other being the Netherlands). In 2017 the UK imported 6.17 bcm of LNG and was Europe's fifth largest importer of LNG. Production of gas in the UK has been in decline since 2009, and since 2004 the UK has been a net importer of gas. The UK imports natural gas by pipeline from Norway, Belgium and the Netherlands, and by LNG to its three operational large-scale LNG terminals: Grain LNG, Dragon LNG and South Hook LNG. When the Grain LNG terminal came into operation, UK's regasification capacity increased by 147%. By 2014 the UK's LNG imports had declined by 45% from their 2011 peak; however, 2014 saw a 21% increase in LNG imports, driven in part by weaker than expected prices in Asia. In 2015 net LNG imports grew a further 12.4% to 9.43 bcm, making the UK the largest importer of LNG in Europe. In 2017, UK LNG imports fell by approximately 34.7% compared with 2016 and the UK dropped to being the fifth largest importer of LNG in Europe.

Grain LNG Terminal. The Grain LNG terminal is located on the Isle of Grain in Kent. The first commercial cargo of LNG arrived at Grain in September 2005. The terminal was expanded in 2008 to accommodate an additional 9.3 bcm per year and again in 2010 when a further 6.9 bcm per year of capacity was added. Grain LNG is planning a further expansion to increase the terminal's capacity from 19.5 bcm/year to up to 27.5 bcm/year towards the end of 2020 and will make it the largest import terminal in Europe. The Grain LNG terminal offers cooling down and ship reloading services, and road tanker loading services, and was the first UK facility to offer reloading. Small-scale ship reloading facilities are being considered.

Dragon LNG Terminal. The Dragon LNG terminal is located at Milford Haven in west Wales. It came into operation in 2009. The terminal has a maximum gas send-out rate of 7.6 bcm/year.

South Hook LNG. South Hook, also located at Milford Haven, was commissioned in 2009. And has a capacity of 21 bcm/year, making it the largest LNG receiving terminal in Europe.

4.4 Main Failure Modes of LNG regasification plants

The CEN standards generally propose a subdivision of hazards for LNG plants in two classes, depending on the origin of the threat: (1) hazards of internal origin, arising from both LNG and non-LNG related process operations and loss of containment; and (2) hazards of external origin, arising from outside the plant. The hazards of internal origin can be further distinguished in (1.a) hazards related to loss of containment of LNG or natural gas and (1.b) hazards which are not specific of natural gas. The hazard related to loss of containment of LNG and natural gas depend on the hazardous properties of these materials and on the process conditions.

LNG and natural gas are flammable materials, and may be found in the plant at low temperatures and/or high pressure. The standard EN 1160:1996 identifies three main potentially hazardous characteristics of LNG:

- It is extremely cold (it boils at about -160°C, and the vapour at that temperature is more dense than ambient air);
- Small volumes of liquid are converted into large volumes of gas (approximately 600 normal volumes of gas per volume of liquid);
- It is a flammable hydrocarbon gas (the flammable mixture range with air is from approximately 5% to 15% gas by volume, at ambient conditions).

The hazards related to loss of containment of LNG and natural gas are considered for all items of equipment in the plant, including the loading or unloading of road tankers or LNG carriers. For example, in the hazard assessment of storage tanks, the internal threats to integrity to be assessed include:

- Mechanical failure (e.g. thermal shock, corrosion, frost heave of foundation, leakage of flanges);
- Equipment failure (relief valves, liquid level gauging etc.); and
- Operational and maintenance errors (overfilling, rollover, dropped pump, overpressure etc.)

Internal hazards which are not specific to LNG are related to the presence of other hazardous materials and equipment in the plant. Qualitatively, they do not differ from the analogous hazards commonly found in process and chemical industries, for instance: Poor communication between ship and shore; Traffic within the plant; Leakage of other hazardous substances; Missiles originating from explosion; Pressurised and steam raising equipment; Fired heaters and boilers; Rotating machinery; Electrical installations; Harbour installations associated with the LNG plant; Security issues (e.g.: Intrusion, sabotage); Accidents during construction and maintenance; Escalation of accidents. In Section 4.4.1 we discuss more in details internal hazards.

Considering the hazard of external origin, hazards typical of chemical & process plants are generally included, such as: exposure to sea conditions; LNG carriers approaching the berth at excessive speed or angle; the possibility of collision with the jetty and/or LNG carrier at berth by heavy displacement vessels passing the berth; impact of projectiles and consequences of collision (ship, truck, plane); natural climatic events (lightning, flooding, earthquakes, tidal bores, icebergs, tsunamis); proximity of airports and/or flight-paths, including helicopter crashes; domino effects resulting from fires and/or explosions at adjacent premises; terrorist attacks, and so forth. In Section 4.4.2 we discuss more in details external hazards.

The remainder of this section was developed mainly relying on the analysis carried out by the INtreg project[2]. iNTeg-Risk (Early Recognition, Monitoring, and Integrated Management of Emerging, New Technology related Risks) was a FP7 project that coordinated research and development sub-projects related to new materials and technologies for establishing a common EU approach to face the challenge of emerging risks. One of such sub-projects investigated the management of emerging risks related to technologies available for LNG regasification terminals (iNTeg-Risk project 2011a).

The methodology for the quantification of risk from installations handling toxic or flammable substances can in broad terms be separated into three major phases: (1) the assessment of plant damage states and their frequency of occurrence; (2) the assessment of consequences of toxic or flammable substances release; and (3) the risk ranking (iNTeg-Risk project 2011b).

The assessment of plant-damage states consists in the analysis of the installation to identify potential accident initiators, assess the response of the plant to these initiators and establish end damage states of the plant resulting in the release of a dangerous substance in the environment. The main sources of potential

[2] http://www.integrisk.eu-vri.eu/

hazardous-substance releases are first identified and the initiating events that can cause such releases are determined. A logic model for the installation is then developed. The model includes each and every initiator of potential accidents and the response to the installation to these initiators. Specific accident sequences are defined (event trees) consisting of an initiating event, specific system failures or successes and their timing, and human responses. System failures are in turn modelled (in models called fault trees) in terms of basic component failures and human errors to identify their basic causes and to allow for the quantification of the system failure probabilities and accident sequence frequencies. Plant damage states are defined to uniquely characterize the installation-dependent conditions of release of the hazardous substance. Accident sequences resulting into the same conditions of release are grouped into groups each corresponding to a particular plant damage state. The final step consists of calculating frequency of occurrence for each identified accident sequence and consequently of each plant damage state. Normally these assessments are aimed at establishing consequences to the public and worker's health, and not plant availability.

The second phase of a typical risk assessment aims at the establishment of the consequences of the released hazardous substances. For toxic substances the assessment of the consequences involves determining release categories for toxic materials, simulating the atmospheric dispersion of such materials, assessing the doses that workers and the public will be exposed and finally assessing the consequences. A parallel set of steps can be distinguished for the assessment of the consequences of released flammable substances. In particular, the consequence assessment consists of the use of appropriate dose/response models that receive as input the dose of heat radiation or overpressure and calculate the probability of fatality or injury of the individual receiving the dose.

In this last phase, the frequencies of the various accidents are integrated with the corresponding consequences, resulting in the quantification (or ranking) of risk. Two risk measures are usually used to quantify risk: individual fatality risk at a location and group fatality risk in a given area.

4.4.1 Internal hazards

As discussed, a typical LNG regasification terminal comprises the following main sections: the jetty, storage tanks, vaporizers, the boil-off recovery system, and auxiliary and safety systems. The section of auxiliary systems includes all the principal process support activities (principal and emergency electric energy, fire control system, refrigeration system, etc.). Three main operating states of the installation are normally considered: (a) the loading of LNG from the ship to the tank; (b) the storage of LNG in the tanks; and (c) the transfer of LNG from the tank to the pipeline. (iNTeg-Risk project 2011a) identified four critical sections of the plant.

Unloading arm section, comprising the jetty, the unloading arms for the LNG transfer from ship to tanks and the transfer pipeline from the jetty to the storage tanks.

Storage Tanks section, comprising containment tanks with associated piping and pumps.

Absorption / Vaporizer section, comprising the absorption tower, vaporizers as well as their pumping system and the transfer line to distribution net.

Boil-off recovery section, comprising the cryogenic compressors and the blower.

4.4.2 External hazards

(iNTeg-Risk project 2011a) revised a number of available sources to identify and discuss threats associated to external hazards (natural hazards and to intentional malicious acts) sessions. Several sources were analysed, from industrial practice (HazId guidewords used in a major oil company, the California State Island Commission study on Port Cabrillo LNG Port, the EIA study of LNG terminal in Hong-Kong), various standards applicable to LNG facilities and equipment (EN 1473:2007; EN 13645:2001; EN 14620:2006; EN 1474:2008) and from security/vulnerability assessment studies (such as Sandia, SVA Port Cabrillo, SFK and API). From the list of threats derived from these sources, security-related threats were merged and consolidated as follows:

- Deliberate misoperation/manipulation by insider;
- Interference by insider;
- Arson by insider;
- Hijacking (and misoperation/manipulation, interference, arson or use of explosives);

- Hijacking and ramming/collision/grounding;
- Intentional collision by vehicle/ship/airplane/helicopter;
- Intentional collision with carrier of explosive devices/mine;
- Shooting (large/small missiles);
- Cascade of man-made incidents outside the plant;
- Theft of hazardous substances.

Table 4. Typical threats related to external actions and environment for LNG regasification facility.

Natural	Climate extremes	Temperature (extreme high/low), waves/swells, extreme current, flooding, tides/tidal waves/bores, wind/typhoons/squalls, hurricane, tornado, dust, sandstorms, snow, blizzards, ice, icebergs, high humidity, reduced visibility
	Lightning	
	Seismic activity	Earthquakes, Tsunami
	Erosion	Ground slide, coastal, river
	Subsidence/movement	Ground structure, foundations, mooring structure
Man Made	Terrorist activity	Direct attack leading to loss of containment (Deliberate misoperation and/or manipulation by insider, Arson by insider, Hijacking and misoperation and/or manipulation, interference, arson or use of explosives), Hijacking and ramming, collision, grounding, Intentional collision by vehicle, ship, airplane, helicopter, Intentional collision with carrier of explosive devices/mine, Shooting (large/small missiles), Cascade of man-made incidents outside the plant, Theft of hazardous substances
	Social instability	Riots, civil disturbance, strikes, military action, political unrest
	Previous site contamination	Base line study, chemical, organic, radioactive
	Third party activities	Farming, Fishing, Local industry, Commercial and touristic ships
Collisions & impacts	Internal sources of impact	Dropped object, In-facility vehicles, Layout hazards
	External sources of impact	Marine collision, Helicopter impact, FSRU listing, LNG carrier listing, Aircraft crash, External vehicles, Layout hazards, Displacement from nearby heavy vessels
	Industrial domino	Neighbouring plants/facilities, Layout hazards
	Other external sources of ignition	HV cables, Layout hazards, high energy radio waves
Structure stability & positioning	Loss of structural stability	Fatigue/cracking, Structural/foundation failure, Tank sloshing, Loss of station keeping, Loss of buoyancy, Foundering, loss of stability
	Loss of position, drifting	Mooring line failure, Loss of station keeping, Structural failure, grounding

Source: (iNTeg-Risk project 2011c).

This list was then merged to threats related to natural hazards and to specific threats present for floating or off-shore units, obtaining the list summarised in Table 4 of typical threats related to external actions and environment.

4.4.3 Initiating events and plant damage states

All initiating events (related to both internal and external hazards) and corresponding plant damage states identified by (iNTeg-Risk project 2011a) are presented in Table 5.

Table 5. List of initiating events, plant damage states and release categories of the on shore plant.

Initiating Events	Plant Damage State
Unlading section	
1. Corrosion	Hole in piping
2. Boil off removal malfunction during unloading	Pipe rupture
3. Excess external heat in jetty during unloading	
4. Excess external heat during unloading	Pipe rupture
5. Pressure shock (Inadvertent valve closure during unloading)	Pipe rupture (ship to tank)
6. Earthquake	Pipe rupture
7. Inadequate cooling of loading arm	Pipe rupture
8. Snow, ice	Pipe rupture
9. Floods	Pipe rupture
10. High winds	Pipe rupture
11. Extra loads	Pipe rupture
12. Valve left open before unloading starts	Exit of LNG through 1 inch drainage valve
13. Containment bypass during unloading	Exit of LNG through 1 inch drainage valve
14. Damage in boil off gas return pipe	Gas pipe rupture
LNG tank (Loading phase)	
15. Corrosion	Hole in tank
16. Boil off removal malfunction during loading	Tank rupture owing to overpressure
17. Excess external heat during loading	Tank rupture owing to overpressure
18. Level rise beyond safety height, or overfilling	Tank rupture owing to overpressure
19. Rollover	Tank rupture owing to overpressure
20. Earthquake	Catastrophic rupture of tank
21. Snow, ice	Catastrophic rupture of tank
22. Floods	Catastrophic rupture of tank
23. Extra loads	Catastrophic rupture of tank
24. Valve left open before loading starts	Exit of LNG through 1 inch drainage valve
25. Containment bypass during loading	Exit of LNG through 1 inch drainage valve
LNG tank (Storage phase)	
26. Corrosion	Hole in tank
27. Boil off removal malfunction during storage	Tank rupture owing to overpressure
28. Excess external heat during storage	Tank rupture owing to overpressure
29. Rollover	Tank rupture owing to overpressure
30. Earthquake	Catastrophic rupture of tank
31. Snow, ice	Catastrophic rupture of tank
32. Floods	Catastrophic rupture of tank
33. Extra loads	Catastrophic rupture of tank
34. Valve left open	Exit of LNG through 1 inch drainage valve
35. Containment bypass during storage	Exit of LNG through 1 inch drainage valve
LNG tank (Unloading phase)	
36. Corrosion	Hole in tank
37. Boil off removal malfunction	Tank rupture owing to overpressure
38. Inadvertent start of additional compressor	Tank rupture owing to underpressure
39. Excess external heat during unloading	Tank rupture owing to overpressure
40. Continuation of unloading beyond lower safety level	Tank rupture owing to underpressure
41. Increased send out rate from tank	Tank rupture owing to underpressure
42. Earthquake	Catastrophic rupture of tank
43. Snow, ice	Catastrophic rupture of tank
44. Floods	Catastrophic rupture of tank
45. Extra loads	Catastrophic rupture of tank
46. Valve closure after pumps	Pipe rupture
47. Valve left open before unloading starts	Exit of LNG through 1 inch drainage valve
48. Containment bypass during unloading	Exit of LNG through 1 inch drainage valve

Initiating Events	Plant Damage State
Recondenser and vaporizer section	
49. Corrosion	Hole in equipment
50. Excess external heat	Equipment rupture owing to overpressure
51. Pressure shock	Pipe rupture
52. Earthquake	Catastrophic rupture of equipment
53. Snow, ice	Catastrophic rupture of equipment
54. Floods	Catastrophic rupture of equipment
55. Extra loads	Catastrophic rupture of equipment
56. Valve left open	Exit of LNG through 1 inch drainage valve
57. Containment bypass	Exit of LNG through 1 inch drainage valve
Boil-Off recovery section	
58. Corrosion	Hole in equipment
59. Excess external heat	Equipment rupture owing to overpressure
60. Earthquake	Catastrophic rupture of equipment
61. Snow, ice	Catastrophic rupture of equipment
62. Floods	Catastrophic rupture of
63. Extra loads	Catastrophic rupture of equipment
64. Valve left open	Exit of LNG through 1 inch drainage valve
65. Containment bypass	Exit of LNG through 1 inch drainage valve
66. Increased flow rate	Catastrophic rupture of recondenser
67. Pump malfunction (exit of recondenser)	Catastrophic rupture of recondenser
Send out pipeline	
66. Pipe break owing to corrosion	Small hole on pipe skin (Leakage)
67. Pipe break owing to external heat	Overpressure creates small hole
68. Pipe break owing to pressure shock- closed valve in send out	Pipe rupture
69. Pipe break owing to containment bypass	Exit of LNG through sampling valves
70. Vaporiser failure	Pipe rupture

Source: (iNTeg-Risk project 2011a).

Screening of the initiating events was performed on the basis of their release category. Release categories with relatively small releases were not quantified. For example liquid releases which occur if there is containment bypass or corrosion in the LNG tank were ignored and the corresponding initiating events not be quantified. Containment bypass was also ignored in the unloading and loading section of the LNG tank. The initiating event of earthquake was not be considered as being beyond the scope of that analysis. The initiating events that were subject to quantification in the iNTeg-Risk project are summarised in Table 6 and explained more in detail in the following.

Boil off removal malfunction during unloading from ship to tank. During unloading of LNG from ship to tank the operation of one compressor is required to remove LNG vapours and keep the pressure within safety limits. Any deviation of the boil-off removal safety system from the required operation initiates a transient and requires certain safety functions to avoid release of LNG.

Excess external heat during unloading from ship to tank. During unloading of LNG from ship to tank excess external heat or higher than expected temperature in product may cause an additional demand on the boil off removal capacity of the storage facility. The extra demand initiates a transient and requires certain safety functions to avoid release of LNG.

External fire during unloading from ship to tank. During unloading of LNG from ship to tank an external fire in jetty may ignite and due to the higher thermal heat flux which is radiated towards the pipes increasing boil off removal capacity is required, and has to be handled through the safety functions of the plant.

Inadvertent valve closure during unloading from ship to tank. During unloading of LNG from ship to tank a valve may close abruptly causing a water hammer in the loading arm. The inadvertent closure of the valve causes a sudden increase in pressure in the pipe and initiates a transient that requires certain safety functions to avoid water hammer and release of LNG.

Inadequate cooling of loading arm during unloading from ship to tank. During unloading of LNG from ship to tank the inadequate cooling of the loading arm may cause an abrupt temperature rise that may cause a pressure increase. This abnormality initiates a transient and requires certain safety functions to avoid release of LNG.

Table 6. List of possible initiating events for LNG regasification facility.

Unloading Section
1. Boil off removal malfunction during unloading from ship to tank
2. Excess external heat during unloading from ship to tank
3. Excess fire in jetty during unloading
4. Inadvertent valve closure during unloading
5. Inadvertent cooling of loading arm
6. High winds
LNG tank
7. Level rise beyond safety height, or overfilling
8. Rollover in tank during unloading
9. Rollover in tank during storage
10. Inadvertent starting of additional Compressors
11. Boil off removal malfunction during storage
12. External fire near tank
13. Continuation of unloading beyond lower safety level (Low level in tank)
14. Increase send out rate from tank
Loading section (from refrigerated tank to pumps and heater)
15. Closed valve in sendout from tank
16. Increased flow rate to recondenser
17. Booster pumps malfunction
18. External fire near recondenser
19. Vaporiser failure
20. Strong waves during unloading (only for offshore plant)
21. Strong waves during storage (only for offshore plant)

Source: (iNTeg-Risk project 2011a).

High winds/ waves in loading arm during unloading from ship to tank. During unloading of LNG from ship to tank the presence of high winds initiates a transient and requires certain safety functions to avoid release of LNG.

High level in tank during unloading from ship to tank. During the loading of LNG from ship to tank, an excess level may occur, should the loading process not stop (in the ship) once the amount of LNG necessary to reach the upper safety limit has been unloaded. Such an event, if unchecked, may lead to the failure of the tank and/or of the piping connecting the ship with the tank. The successful mitigation of this event requires the success of certain safety functions.

Rollover in tank during unloading from ship to tank. During the loading of LNG from ship to tank, a variation in the LNG density or temperature may cause a rollover inside the tanks due to the difference between the old and the new product. Such an event, if unchecked, may lead to the failure of the tank. The successful mitigation of this event requires the success of certain safety functions.

Rollover in tank during storage. During the storage of LNG, a variation in the LNG density or temperature may cause a rollover inside the tanks. Such an event, if unchecked, may lead to the failure of the tank. The successful mitigation of this event requires the success of certain safety functions.

Inadvertent Starting of Compressor during storage. Such an event initiates an accident in tank, since it causes an excessive pressure reduction in it owing to the higher boil off gas removal rate, and requires the success of certain safety functions to avoid the release of LNG.

Boil off removal malfunction during storage. During storage of LNG boil off removal is required to keep the pressure within safety limits. Any deviation of the boil-off removal safety system from the required operation initiates a transient and requires certain safety functions to avoid release of LNG.

External fire near tank. An external fire may ignite near the tank and has to be handled through the safety functions of the plant.

Low level in tank during send out. This event may happen during the send out of the tank, when the unloading is continued beyond the lower safety level. If the LNG pumping still continues in the tank, a pressure drop will be registered. The same phenomenon can be observed during the storage phase of the plant, if the send out procedure is inadvertently initiated and continued. The loss of level triggers an accident sequence and requires certain safety functions to avoid release of LNG.

Increased send out rate from tank. This event may occur during the send out of the tank, when the unloading rate is increased unexpectedly. If the LNG pumping continues operating, a pressure drop will be registered. The pressure drop triggers an accident sequence and requires certain safety functions to avoid release of LNG.

Closed valve in send out from tank. This event corresponds to a closed valve in send out that may block the flow and cause a pressure increase. This event usually corresponds to a human error that triggers an accident sequence and requires certain safety functions to avoid release of LNG.

Inadvertent Starting of Compressor to recondenser. Such an event initiates an accident in recondenser, since it causes an excessive pressure increase in it, owing to high gas inlet, and this requires the success of certain safety functions to avoid the release of LNG.

Booster pumps malfunction at the exit of recondenser. Such an event initiates an accident in recondenser, since it causes an excessive pressure increase in it, owing to the blockage of the vessel exit. This situation requires the success of certain safety functions to avoid the release of LNG.

External fire near recondenser. An external fire may ignite near the recondenser vessel and has to be handled through the safety functions of the plant.

Vaporizer failure. This event corresponds to a vaporizer failure that may result in letting liquid natural gas pass in the outlet piping. This event triggers an accident sequence and requires certain safety functions to avoid pipe break and release of natural gas.

Strong waves during unloading. During unloading of LNG from ship to tank the presence of strong waves initiates a transient and requires certain safety functions to avoid release of LNG. The release may be the result of the impact of the ship on the offshore facility.

Strong waves during storage. During storage the presence of strong waves or currents initiates a transient and requires certain safety functions to avoid release of LNG. The release may be the result of the movement of the offshore facility due to the strong waves.

4.4.4 Conclusion on main failure modes of LNG regasification plants

The more critical plant damage states are those associate with the potential of releasing critical quantities of LNG into the environment. These were identified as below:

- LNG Tank

1. Tank rupture (roof failure) owing to overpressure
2. Tank rupture (roof failure) owing to overfilling
3. Tank rupture owing to under-pressure

- Loading section

4. Tank rupture (roof failure) owing to overpressure

- Unloading section

5. Tank rupture (roof failure) owing to overpressure

- Send-out pipeline

6. Tank rupture owing to under-pressure

4.4.5 Available data on LNG incidents

The International Group of Liquefied Natural Gas Importers (GIIGNL) has developed a programme for collecting and analysing safety incidents in the facilities of its members. Acton et al. provides a summary of this programme and the main conclusions that can be derived from it. Data collected in this programme correspond to the period 1965 – 2007 and fed a database. The authors of this this document are not aware of any update of the report of Acton et al. with data obtained after 2007.

Data were collected by means of a questionnaire developed by a Technical Study Group and shared with members of GIIGNL. The main focus of this questionnaire was on incidents involving releases of hazardous materials (LNG, Liquefied Petroleum Gases – LPG, Natural Gas Liquids - NGL, liquid Nitrogen, or other hydrocarbon gases) that lead or with the potential to lead to injuries to people or damage to equipment or buildings, but also on near misses and on other incidents of concern.

Eventually, by the time of reporting the databased contained 328 incidents. Among the variables used to classify incidents is the quantity of released material, which is divided in three ranges: less than 100 kg, between 100 kg and 1,000 kg and above 1,000 kg. Incidents were also grouped according to the function of the equipment where the incident took place. The groups used were similar to the initiating events considered in section 4.4.3: unloading, storage, send-out, external and other. Incidents during unloading are the most frequent per hour of operation, although authors stress that the number of operating ours corresponding to unloading is relatively infrequent operation compared with other activities in an LNG plant, typically 16 – 20 hours per week.

The accumulated operative experience contributing to this database is 1,320 site-years, 5,816 tank-years, 53,295 ship-voyages and 2,556 bcm. Table 7 contains the summary of incidents collected of most interest to our study.

Table 7. LNG incident frequencies.

Period	Incidents	Operating site-years	Frequency (incidents/site-year)
1965-1974	15	44	0.341
1975-1984	52	179	0.291
1985-1994	94	327	0.287
1995-2000	85	191	0.445
2001-2007	82	579	0.142
Total 1965-2007	328	1320	0.248

Source: Acton et al. JRC has rounded off values in the last column to three significant digits instead of to two, as it was in the original source

This table contains very interesting information concerning LNG regasification facilities to be used in a Risk Assessment of a gas system. It provides the historical frequencies of occurrence of incidents in LNG plants. We can see that the frequency of incidents per site-year stayed approximately stable in the period 1965-1994, it experienced a significant increase in the period 1995-2000 and dropped a significantly in the period 2001-2007[3]. The significance of these differences can be checked by performing the corresponding hypothesis tests for the fraction of years (or months) that experienced an incident in each period. By doing so we reach the conclusion that the entire reporting period can be divided in three periods with different probability of incidents per site-year: Period 1965-1994 with a frequency of 0.293 incidents per site-year, the period 1995-2000 with a frequency of 0.445 incidents per site-year, and the period 2001-2007 with a frequency of 0.142 incidents per site-year.

[3] In this sentence we are using the words significant and significantly with its statistical meaning: the differences in frequencies of incidents among the different periods are either statistically significant or not. To be able to make the statements in this sentence we have performed the corresponding hypothesis tests for two Poisson variables, adopting as null hypothesis H_0: $\lambda_1=\lambda_2$, and as alternative hypothesis H_1 $\lambda_1\neq\lambda_2$. The tests of hypothesis among the periods 1965-1974 and 1975-1984, 1975-1984 and 1985-1994, and 1965-1974 and 1985-1994 resulted in respective P-values of 0.66, 0.96 and 0.68 which clearly indicate complete lack of significant differences. This took as to consider definitely the period 1965-1994 as a homogeneous period with a constant frequency of incidents. Three more tests were done comparing periods 1965-1994 and 1995-2000, 1995-2000 and 2001-2007, and 1965-1994 and 2001-2007. The largest P-value of these three hypothesis tests was 0.006, which leads to a clear rejection of the null hypothesis in the three cases. There is a clear statistical evidence to support the statement that the frequencies of incidents of these three periods are different. See Annex 3 for details.

Taking into account that most of these incidents take the plant to stop the normal activity in order to avoid any escalation, these frequencies may be taken as estimates of the probability of non-availability of the plant to deliver gas to the national gas transmission network, or equivalently probability of failure of the facility. The problem we face now is which of the three, or four estimates, if we consider also the average frequency over the entire period (0.248 incidents per site-year), should be taken. This is particularly difficult to do because of the non-smooth evolution of the frequency over time, with an increase after a long stable period of time followed by a sharp drop (0.445 to 0.142). This decision is difficult to adopt without additional information. One possibility would be to take 0.142 as an optimistic estimate, 0.445 as a pessimistic estimate and 0.248 as a central estimate. The fact that the estimate 0.445 is the one obtained with the smallest observation period (191 site-years vs 550 and 579) take us to consider the other estimates more reliable.

A final remark should be done. All these estimates have been done assuming that incidents occur equally probably over each period considered and over all plants reporting to the database. This hypothesis has not been confirmed by the authors of this document because we have had access only to aggregated data. In case this hypothesis were not fulfilled, other type of analysis should be performed. Nevertheless, in absence of more information, estimates suggested in the previous paragraph are reasonably good to be used in a Risk Assessment of a natural gas transmission network.

5 Compressor Stations

Compressor stations are an integral part of the natural gas pipeline network that moves natural gas to consumers from production (or at least import) sites. As gas flows through pipelines its movement is slowed above all by friction over distance and elevation differences, reducing pressure. Compressor stations are thus needed to create the required pressure gradients that produce the flow along the pipelines, and are placed strategically within the transportation pipeline network to maintain gas flow and pressure. Gas transmission system operators typically build compressor stations roughly every 100 kilometres.

Natural gas compression generates heat that must be dissipated before leaving the compressor facility, most compressor stations possessing an aerial cooler system for the purpose. As with other facilities handling fuels, compressor stations must possess a variety of safety systems for protection in the event of emergencies such as unanticipated pressure drop or natural gas leakage. Emergency shutdown systems are intended to detect abnormal conditions, automatically stop compressor units and isolate and vent compressor station gas piping. Other compressor station components include backup generators, metering equipment, filtration systems and control/monitoring systems. Natural gas entering a compressor station is passed through scrubbers and filters to remove any liquids and solids/particulate matter and once the gas stream has been cleaned, it is directed to individual compressors according to the flow and number of units that are needed to handle the scheduled system flow requirements.

When the required boost in pressure is very high, either large multistage compressors or several compressor units operated serially can be used in order to achieve the desired pressure. In operational terms most compressor units operate in parallel, individual compressor units handling a fraction of the necessary flow at the required additional pressure before directing the gas back into the pipeline. The size and number of compressors installed in each compressor station thus varies based on pipe diameters and the volume of gas to be moved. These factors, together with their arrangement, has a significant impact on the availability, fuel consumption and capacity of the system (Kurz and Lubomirsky 2011).

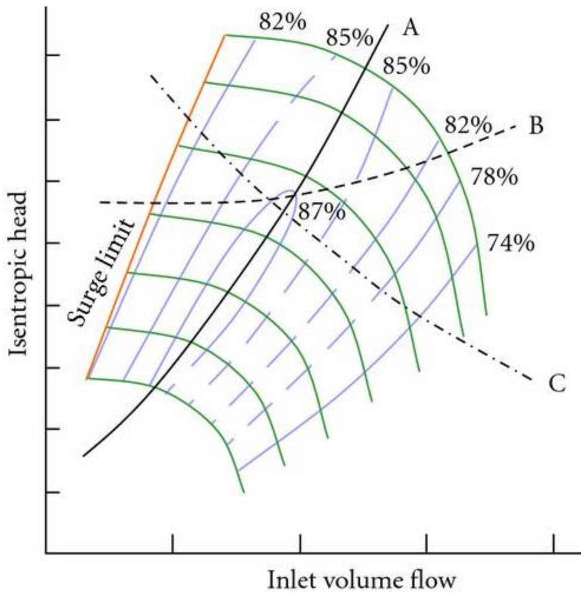
5.1 Types and operation of Compressor Stations

The matter of selecting the arrangement of compressors in station is usually considered both in the light of steady-state aerodynamic performance and regarding transient behaviour, redundancy strategies and slack/growth capabilities. The number of compressors installed in each compressor station of a pipeline system has a significant impact on the availability, fuel consumption, and capacity of the system and will depend on the station's load profile.

The operating point of a compressor is determined by a balance between available driver power, the compressor characteristic, and the system behaviour. The compressor characteristic also includes the means of controlling the compressor, such as variable speed control, adjustable inlet guide vanes, suction or discharge throttling and recycling. If variable speed control is available, for example if the driver is a two-shaft gas turbine or a variable speed electric motor, it is usually the preferred control method. A typical compressor map for a speed-controlled compressor is shown in Figure 9, illustrating the area of possible operating points, the lowest flow possible being determined by the surge line. The compressor set point is determined by the relationship between pressure ratio (head) and flow dictated by the system. Line B depicts a system where suction and discharge pressure are more or less fixed and thus change very little with changes in flow. Line A shows the typical behaviour of a pipeline, where any change in flow will impact the pressure drop due to friction in the pipeline. Line C is typical for storage applications, where the pressure in the storage cavity increases with the amount of gas stored. If the compressor is operated at maximum power, the initial flow will be high due to the initially low pressure ratio. The more gas is stored in the cavity, the higher its pressure, and likewise the required discharge pressure. Being power limited, the operating point then moves to a lower flow (Kurz and Lubomirsky 2011)

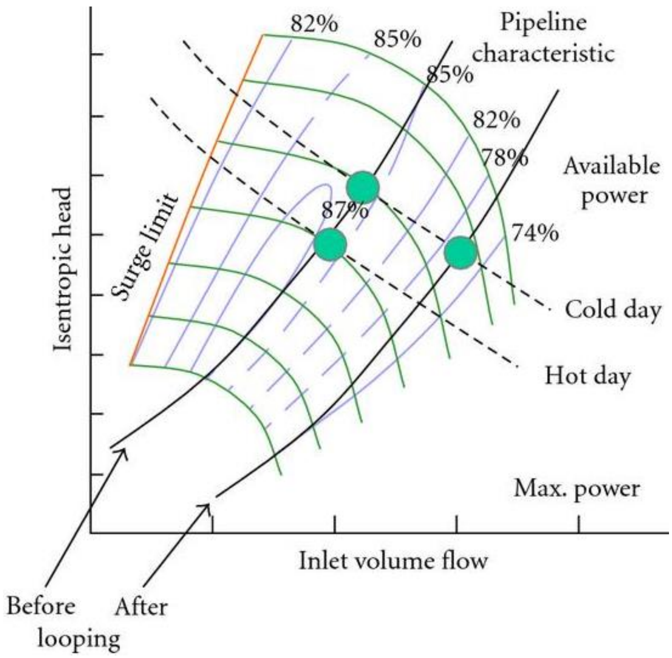
In case of a pipeline, the operating point of the compressor is always determined by the power available from the driver (Figure 10). In the case of a gas turbine driver, the power is controlled by the gas producer speed setting and the pipeline characteristic, this point being found at the intersection between the pipeline characteristic and the available power. Increasing the flow through a pipeline will require more power and more compressor head (Kurz and Lubomirsky 2011).

Figure 9. Typical compressor map



Source: Kurz and Lubomirsky, 2011.

Figure 10. Compressor operating point variations



Source: Kurz and Lubomirsky, 2011.

Operational flexibility under a larger number of different operating scenarios must be ensured, namely in order to cope with hourly, daily, monthly, or seasonal demand variations and considering that the available turbine power will depend on the prevalent ambient conditions. Scenarios that arise from failures of one or more systems also have to be considered (Ohanian and Kurz 2002). Operating limits due to speed limits are undesirable since they mean that the available engine power cannot be used but because a gas turbine can produce far more power at colder ambient temperatures, designs based on worst case ambient conditions may not be optimal. The quest for operational flexibility can be satisfied on various levels. While both compressor and driver should have a wide operating range, using multiple smaller units per station rather than one large unit is another possible approach where a series or parallel arrangement will impact flexibility.

Flow demand and head requirements are often coupled, which is very obvious in pipeline applications where the pressure drop between stations is directly related to the flow. In other applications operating points are limited by the maximum available engine power, as for example in storage operations where the goal is to fill the storage cavity as fast as possible by operating the engine at its maximum power. Since the filling starts at very low pressure differentials, the flow is initially very high but as the cavity pressure and the pressure ratio increase the flow is reduced. For such applications compressor arrangements that operate two compressors in parallel during the initial stage, with the capability to switch to a series operation, are very advantageous (Kurz and Lubomirsky 2011).

Dynamic studies of pipeline behaviour reveal a distinctly different reaction in station operating conditions than for steady-state calculations. In steady state (or for slow changes), pipeline hydraulics dictate an increase in station pressure ratio with increased flow due to the fact that the pipeline pressure losses increase with increased flow through the pipeline. However, if a centrifugal compressor receives more driver power and increases its speed and throughput rapidly, the station pressure ratio will react very slowly to this change because the additional flow initially has to pack the pipeline (with its considerable volume) until changes in pressure become apparent. Dynamic changes in operating conditions would lead to a changes in flow without significant discharge pressure changes. Because the failure or unavailability of compression units can cause significant loss in revenue, the installation of standby units must be considered, or the standby function can be covered by oversizing the drivers bearing in mind that oversizing creates an efficiency disadvantage during normal operation, when the units would operate in partial load. The failure of a compression unit does not mean that the entire pipeline ceases to operate but rather that the flow capacity of the pipeline is reduced. Planned shutdowns due to maintenance can be planned during times when lower capacities are required (Kurz and Lubomirsky 2011).

Most compressor stations are fuelled by a portion of the natural gas flowing through the station, although some of the units may be electrically powered. Gas-powered compressors may be driven by either conventional piston engines or natural gas turbine units, as discussed further below. There may be one or more individual compressor units at a station, more often housed in a building to facilitate maintenance. The key parameters for the characterization of the compressor stations are thus the "prime mover" types of engines that drive the different possible compressors types, since significant differences related to maintenance, to the downtime repair and to different numbers of parts that could fail can be introduced.

The three most commonly used combinations are:

- Turbine/Centrifugal Compressor - a natural gas-fired turbine is used to turn a centrifugal compressor, a small portion of natural gas from the pipeline being burned to power the turbine.
- Electric Motor/Centrifugal Compressor - a centrifugal compressor is driven by a high-voltage electric motor. One advantage of electric motors is they need no emission permits since no hydrocarbons are burned as fuel. However, a highly reliable source of electric power must be available near the station for such units to be considered for an application.
- Reciprocating Engine/Reciprocating Compressor - large piston engines are fuelled by natural gas from the pipeline. Reciprocating pistons, located in cylinder cases on the side of the unit, compress the natural gas. The compressor pistons and the power pistons are connected to a common crankshaft. The advantage of reciprocating compressors is that the volume of gas pushed through the pipeline can be adjusted incrementally to meet small changes in customer demand.

When compared with centrifugal compressors, reciprocating compressors typically have higher compression ratios, lower gas flows and higher efficiencies, being are suitable for low and middle volumes in the whole pressure and compression ratio ranges. They are applied mainly in smaller dimension transit gas pipelines, especially multi-cylinder engines with compression pistons and combustion cylinders sharing the same engine block that are thus compact and easy to adjust.

Centrifugal compressors have the advantages of being more stable and of handling much higher flows. As rotation is the only type of motion present, requirements on maintenance and revision are much lower compared with reciprocating compressors. The centrifugal compressors are used mainly for compressing very high gas volumes at a comparatively low compression ratio but steady pressure value. They are the most used compressors in transmission and transit gas pipelines, for gas compression into the underground storage or as emergency/reserve power units (combustion turbines of electric generators). One or two-stage machines are used for transmission applications, while multi-stage (often with intercooling) machines are used for injection into underground gas storage. Axial turbo compressors are not used for gas transmission *per se* but rather in the turbines that drive the centrifugal compressors. The use of the steam turbines is very rare as mentioned below.

In more practical terms, a study was commissioned by JRC in order to develop a classification of compressor stations, and while the main purpose was the description of the main facility failure modes in terms of causes, taxonomy and effects, it also established a taxonomy of compressor station types. The study was performed with JRC input by Tractebel Engineering, a subsidiary of the ENGIE group, and could thus rely on extensive data from the large number of facilities of the parent company, in particular 56 compressor stations throughout the EU: 9 in Germany (Bunde, Eischleben, Lippe, Mallnow, Olbernau, Reckrod, Rehden, Reuckersdorf and Weisweiler), 5 in Belgium (Berneau, Winksele, Weelde, Zeebrugge and Zelzate), 2 in France (Etrez and Saint-Avit), 18 in Spain (Alcazar de San Juan, Algete, Almendralejo, Baneros, Chinchilla, Cordoba, Crevillente, Denia, Haro, Montesa, Navarra, Paterna, Puertollano, Sevilla, Tivissa, Villar de Arnedo, Zamora and Zaragoza), 11 in Italy (Enna, Gallese, Istrana, Malborghetto, Masera, Melizzano, Messina, Montesano, Poggio Renatico, Tarsia and Terranova), 5 in Poland (Ciechanow, Kondratki, Szamotuly, Wloclawek and Zambrow), 5 in the Czech Republic (Breclav, Hostim, Kralice, Kourim and Veseli n/L) and 1 in Austria (Eggendorf) (Fioravanti et al. 2019).

In terms of types and operation of compressor stations the study concluded that prime mover sizing takes into account above all company-wide standardization and foreseen market evolution. Installed power was not considered a key parameter in establishing the taxonomy since the availability/reliability of the units and their maintenance and repair downtimes are not dependent upon units' number, size or installed power, the relevant aspect being rather the station's functional architecture and redundancy level. All natural gas compressors encountered in the study are driven either by electric motors or gas turbines, the drivers being the key parameters in characterizing compressor stations given the fact they introduce significant differences regarding maintenance issues, downtime repairs and the different numbers of parts that can fail. Only one steam turbine was encountered (Mallnow, Germany). All compressors were centrifugal multistage units, meaning no reciprocating compressors were present (Fioravanti et al. 2019).

Another important factor was the compressor station redundancy level. The study concluded that the compressor redundancy level is normally set at *N*+1, where *N* is the number of running compressors and "+1" denotes a standby unit. This led to the following considerations:

- If the number of compressors is greater than 3 the compressor station is considered to have partial redundancy;
- If the number of compressors is 2 two further scenarios arise:
  - Total redundancy (1 compressor running and 1 in standby)
  - Null redundancy (2 compressors running with no standby available)
- If the number of compressors is 1 the compressor station has no redundancy.

In case of partial redundancy the running compressors do not normally handle 100% of their nominal/design flow and can thus provide a measure of further redundancy if required. For example, in a 9+1 configuration (where a single compressor is in stand-by) 8 running compressors can easily recover a potential lack of flow rate due the trip/failure of one unit by working closer to the stonewall point. Based on the considerations above, a taxonomy comprising 8 different typologies of equivalent compressor stations was developed, as illustrated in Table 8. *N* denotes at least 3 machines, "TUCO" stands for turbocompressors, "MOCO" for motocompressors (i.e. electrically-driven compressors), "RP" means Partial Redundancy (e.g. 2 at 50%), "RN" means Null Redundancy and "RT" stands for Total Redundancy. These typologies were the basis of a subsequent functional analysis. It is worth mentioning that a small number of facilities in the EU are considerably larger in terms of the number of compressors and total installed power, such as Ommen in the Netherlands (16 compressors in total, split between high caloric and low caloric networks) or Baumgarten in Austria. It was however considered that these "complex" facilities do not need to be acknowledged specifically and analysed as additional categories, as their reliability/availability characteristics do not depend on number and size of compressor units but again on their architectural configuration, i.e. ultimately on the redundancy level and spare part management philosophy of the facilities (Fioravanti et al. 2019).

Table 8. Equivalent compressor stations.

Type	Number of Compressors	Type of Compressors	Redundancy Level
1	N	TUCO	RP
2	N	MOCO	RP
3	2	TUCO	RN
4	2	MOCO	RN
5	2	TUCO	RT
6	2	MOCO	RT
7	1	TUCO	RN
8	1	MOCO	RN

Source: Fioravanti et al., 2019.

It is thus clear that standby units are not always mandatory because modern gas-turbine-driven compressor sets can achieve availabilities above 97% and higher (Kurz and Lubomirsky 2011). It has often been assumed that for two-unit stations without a standby unit, a parallel installation of the two units would yield the best behaviour if one unit fails but that a series arrangement of identical compressor sets can yield a lower deficiency in flow than a parallel installation (Ohanian and Kurz 2002). This is due to the fact that pipeline hydraulics dictate a relationship between the flow through the pipeline and the necessary pressure ratio at the compressor station. For parallel units, the failure of one unit forces the remaining unit to operate at or near choke, with a very low efficiency. Identical units in series, upon the failure of one unit, would initially require the surge valve to open, but the remaining unit would soon be able to operate at a good efficiency level, thus maintaining a higher flow than in the parallel scenario. Given the fact that the linepack will help to maintain the flow to the users, a series installation would often allow for sufficient time to resolve the problem (Kurz and Lubomirsky 2011).

5.2 Failure Data

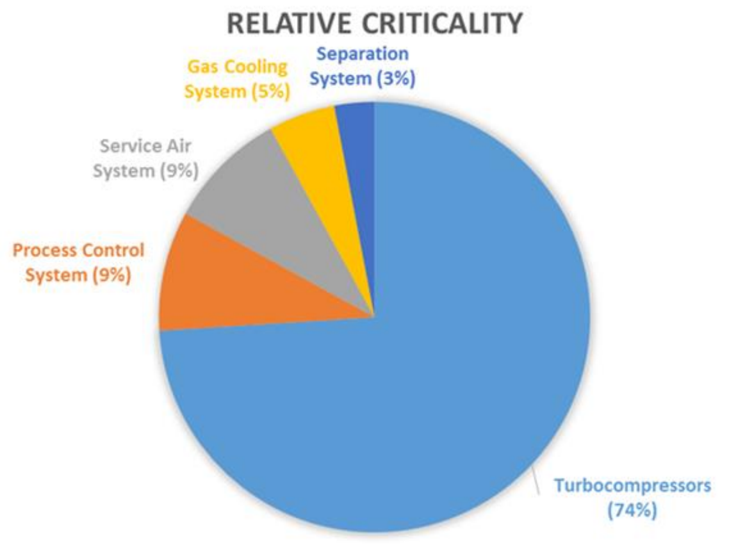
A variety of general databases are standardly used to determine compressor station failure rates, in addition to the large variety of available recent literature dealing with compressor and compressor station fundamentals in terms of both normal operation and main failure types and causes (Mohitpour et al. 2008, Boyce 2011, Bloch and Geitner 2012). Compressor stations are specifically addressed in reliability data estimation studies for various components and facilities of gas transmission networks, where failures rates can be found (Chudoba 2014).

The impact of the type and arrangement of turbomachinery equipment used in compressor stations has been discussed in detail in various references, including topics such as costs (capital, installation, maintenance, fuel, etc.), efficiency, operating range, emissions, availability, operational flexibility and standby requirements, most of which are intimately related to and have implications on facility failure modes (Ohanian and Kurtz 2002, Kurz and Lubomirsky 2011). References dealing with obtaining failure probability distributions and developing models to predict operating compressor out-of-service parameters, for planning and maintenance management purposes, and to evaluate different operation states, can also be found (Pillon et al. 2005).

The OREDA handbook offers guidance with failure rates for gas turbines connected to rotary compressors with a critical failure rate of 1100 per million hours (including a special note that 85% of the failures result from the gear box). The OREDA taxonomy includes many other pieces of hardware in the system which are estimated to account for 60% of the non-gear box outages (OREDA, 2014).

The aforementioned study commissioned by JRC calculated the availability of the aforementioned compressor station and demonstrated that (neglecting inferior order contributions) the contribution of the subsystems to the station unavailability is mainly due to turbo compressors (74%), Process Control System and Service Air System contribute at 9% each, the Gas Cooling System has a contribution of 5% and the Separation System contributes for 3% (mainly due to malfunction of high level switches on condensate separators and condensate tank). Figure 11 illustrates the relative criticality of the main subsystems of a Gas Compression station (Fioravanti et al. 2019).

Figure 11. Criticality of main subsystems.



Source: *Fioravanti et al., 2019.*

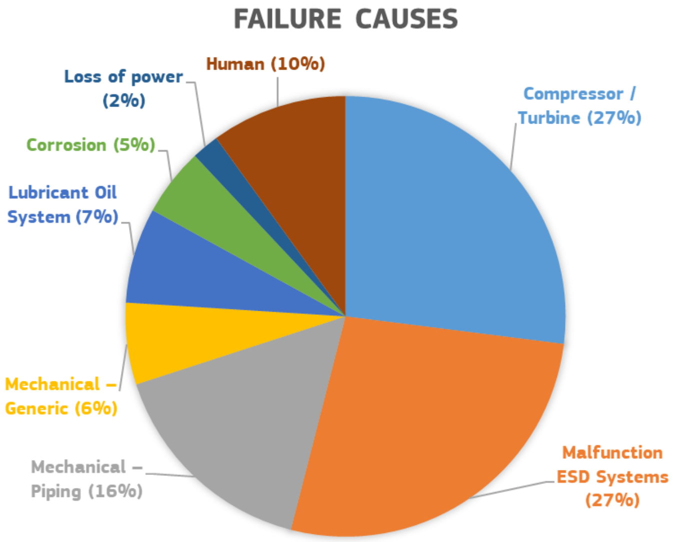
It is evident that compressors are the main contributors to the unavailability of the compressor station; it is important to include in the failure of compressors and their drivers, since the process control system has a non-negligible contribution. The Gas Cooling System has a lower contribution to gas station unavailability and the performed HAZID analysis evidenced that this system is not always. The influence of the separation system is minor but the level switches present in the condensate tank and the condensate separator may trigger a plant shut-down, meaning the spurious intervention of these sensors may have a non-negligible contribution to system unavailability (Fioravanti et al. 2019).

Relevant information about gas transportation facilities can also be found in the database created by PHMSA (PHMSA 2014), which requires pipeline operators to submit reports for incidents, only major accidents being included in practice. The study made use of information on reports of accidents due to technical causes or human errors (184 accidents) that occurred in compressor stations in the period 1986 – September 2014, as illustrated in Figure 12.

About 50% of accidents are due to Mechanical Failures: in 27% of cases it is expressly reported that the failure occurred at the compressor or at the turbine; in 16% of cases the fault location is specified in piping (fittings, gaskets, flanges, valves etc.); in 6% of cases the fault location is not indicated or it is different from the others above cited. Another important cause of failure is the malfunction of controls or emergency shutdown systems, responsible for 27% of the failures (generally by spurious intervention). The lubricant oil system caused 7% of failures (generally leakage of oil that caught fire). Corrosion was responsible for 5% of failures. Loss of power, loss of electric power and emergency generators or batteries failure on demand, caused 2% of failures of gas compression stations. Human errors (errors during maintenance, vehicle collision, improper operation, etc.) contributed for 10% of total cases of failure of gas compression stations.

Also of particular interest is a joint research project by four European TSOs (N.V. Nederlandse Gasunie, The Netherlands; Gaz De France, France; Ruhrgas, Germany; Snam, Italy) which resulted in a methodology and software tool for the safety assessment of compressor stations, listing potential hazards to assess consequences and likelihood. The main steps can be summarized as the sequence: description of all components and systems -> characterization of hazards by means of HAZOP (HAZard OPerability study) -> modelling of undesired events in a top-down approach Fault Tree Analysis -> assessment of failure rates supported by a Det Norske Veritas reliability assessment for components, systems and human factors -> estimation of event frequencies -> calculation of events consequence, analysing explosions, fires and effects on people -> overall safety assessment -> safety improvement strategies (Kutrowski et al. 2006).

Figure 12. Causes of failure in compressor stations.



Source: PHMSA, 2014.

Also of particular interest is a joint research project by four European TSOs (N.V. Nederlandse Gasunie, The Netherlands; Gaz De France, France; Ruhrgas, Germany; Snam, Italy) which resulted in a methodology and software tool for the safety assessment of compressor stations, listing potential hazards to assess consequences and likelihood. The main steps can be summarized as the sequence: description of all components and systems -> characterization of hazards by means of HAZOP (HAZard OPerability study) -> modelling of undesired events in a top-down approach Fault Tree Analysis -> assessment of failure rates supported by a Det Norske Veritas reliability assessment for components, systems and human factors -> estimation of event frequencies -> calculation of events consequence, analysing explosions, fires and effects on people -> overall safety assessment -> safety improvement strategies (Kutrowski et al. 2006).

This methodology bears some resemblance to the work implemented in the study commisoned by JRC, which resulted in a characterization of failure modes in terms of frequency and flow/pressure effect according to types of prime movers and redundancy levels. In order to identify the possible damage classes liable to affect the operation of the transportation network, the aforementioned taxonomy (plus another class for pump failure, cryogenic tank leakage or vaporizer failure at LNG facilities, assumed to consist of 4 storage tanks, each with one low pressure pump - 3 pumps being operative and 1 pump in standby - plus 2 operative and 1 standby high pressure pumps feeding 3 vaporizers, all pumps being driven by electric motors) was analysed and damage classes were defined in terms of flow rate reduction (Fioravanti et al. 2019):

- The 0% flow damage class represents scenarios in which the compressors and the valve that opens the bypass all fail simultaneously, resulting in a total absence of gas flow through the station.
- The 33, 50 and 66% flow damage classes (at nominal pressure) are scenarios in which each percentage of the nominal flow is delivered.
- The "Bypass" damage class is the case of the compression station completely bypassed without performing compression (the pressure having essentially its value upstream of the station) without flow interruption, caused by the concurrent failure of all the compressors but the correct functioning of the bypass valve.

The flow rate reduction refers to the "nominal" expected flow rate by each typical configuration. In configurations with 3 compressors, 2 compressors running and 1 compressor spare (configurations 1 and 2) the 33% and 66% flow damage classes are not applicable. In configurations with 4 compressors, 3 compressors running and 1 compressor spare (configurations 1a and 2a) the 50% flow damage class is not applicable. In configurations s with 2 compressors both running, no spare (configurations 3 and 4) the 33% and 66% flow damage classes are not applicable. In configurations with 2 compressors, one spare (configurations 5 and 6) the 33%, 50% and 66% flow damage classes are not applicable (one compressor running ensures the nominal flow). In configurations with 1 compressor and no spare (configurations 7 and 8) the 33%, 50% and 66% flow damage classes are not applicable (the only compressor ensures the nominal flow) (Fioravanti et al. 2019).

In order to take into account different plant locations, the presence of available stocks, etc. three logistic delay times have been considered:

- 1 h logistic delay time (spare part present in plant warehouse);
- 24 h logistic delay time (spare part shortly available);
- 1 week logistic delay time (spare part not readily available).

For each configuration the study yielded the following data (Fioravanti et al. 2019):

- Unavailability (Q): the probability for the system to be in the considered damage class, i.e. the fraction of time spent by the system in the considered damage class;
- Expected Number of Failures (ENF): the mean number of failures (leading to the considered damage class) expected in the year;
- Down Time: the cumulative time in the year in which the system is in the considered Damage Class;
- Average Down Time: the mean down time of the system for a failure leading to the considered Damage Class, i.e. the average time that is necessary to recover the failure to get out from the considered Damage Class.

Results are summarized in Tables 9 10 and 11 below, presenting the 4 parameters above for each configuration, for the 3 considered three logistic delay times (Fioravanti et al. 2019).

Table 9. 1hr Logistic Delay Time: Unavailability (Q), Expected Number of Failures (ENF), Downtime [h/year], Average Downtime [h].

Corrective + Preventive Maintenance – 1 hr Logistic Delay Time						
Typical	**Parameter**	**Damage Class (nominal flow percentage)**				
		66%	**50%**	**33%**	**Bypass**	**0%**
1: N-TUCO-RP	Q	X	2,08E-02	X	7,37x10E-04	3,41E-06
	ENF [occ/year]	X	4,98E+00	X	2,19E-01	1,05E-03
	Downtime [h/year]	X	1,82E+02	X	6,46E+00	2,98E-02
	Average Downtime [h]	X	3,65E+01	X	2,95E+01	2,84E+01
1a: 4-TUCO-RP	Q	3,31E-02	X	4,74E-04	6,51E-04	2,85E-06
	ENF [occ/year]	7,88E+00	X	2,17E-01	1,64E-01	7,20E-04
	Down Time [h/year]	2,90E+02	X	4,15E+00	5,70E+00	2,50E-02
	Average Down Time [h]	3,68E+01	X	1,91E+01	3,48E+01	3,47E+01

(Table 9 continues next page)

Table 9 (cont.) 1hr Logistic Delay Time: Unavailability (Q), Expected Number of Failures (ENF), Downtime [h/year], Average Downtime [h].

Corrective + Preventive Maintenance – 1 hr Logistic Delay Time						
Typical	**Parameter**	**Damage Class (nominal flow percentage)**				
		66%	**50%**	**33%**	**Bypass**	**0%**
2: N-MOCO-RP	Q	X	2,26E-03	X	4,18E-04	1,84E-06
	ENF [occ/year]	X	4,88E-01	X	1,04E-01	4,60E-04
	Downtime [h/year]	X	1,98E+01	X	3,66E+00	1,61E-02
	Average Downtime [h]	X	4,05E+01	X	3,51E+01	3,50E+01
2a: 4-MOCO-RP	Q	3,64E-03	X	1,95E-05	4,71E-04	2,06E-06
	ENF [occ/year]	7,77E-01	X	8,08E-03	1,14E-01	5,00E-04
	Downtime [h/year]	3,19E+01	X	1,71E-01	4,13E+00	1,80E-02
	Average Downtime [h]	4,10E+01	X	2,11E+01	3,62E+01	3,61E+01
3: 2-TUCO-RN	Q	X	1,14E-01	X	4,16E-03	1,83E-05
	ENF [occ/year]	X	7,44E+00	X	4,24E-01	1,86E-03
	Downtime [h/year]	X	9,98E+02	X	3,65E+01	1,60E-01
	Average Downtime [h]	X	1,34E+02	X	8,60E+01	8,62E+01
4: 2-MOCO-RN	Q	X	3,60E-02	X	7,45E-04	3,26E-06
	ENF [occ/year]	X	2,56E+00	X	1,32E-01	5,77E-04
	Downtime [h/year]	X	3,15E+02	X	6,52E+00	2,86E-02
	Average Downtime [h]	X	1,23E+02	X	4,95E+01	4,95E+01
5: 2-TUCO-RT	Q	X	X	X	1,02E-02	5,72E-05
	ENF [occ/year]	X	X	X	2,50E+00	1,41E-02
	Downtime [h/year]	X	X	X	8,95E+01	5,01E-01
	Average Downtime [h]	X	X	X	3,58E+01	3,54E+01

(Table 9 continues next page)

Table 9 (cont.) 1hr Logistic Delay Time: Unavailability (Q), Expected Number of Failures (ENF), Downtime [h/year], Average Downtime [h].

Corrective + Preventive Maintenance – 1 hr Logistic Delay Time						
Typical	**Parameter**	**Damage Class (nominal flow percentage)**				
		66%	**50%**	**33%**	**Bypass**	**0%**
6: 2-MOCO-RT	Q	X	X	X	1,41E-03	7,48E-06
	ENF [occ/year]	X	X	X	3,25E-01	1,73E-03
	Downtime [h/year]	X	X	X	1,23E+01	6,56E-02
	Average Downtime [h]	X	X	X	3,80E+01	3,78E+01
7-1-TUCO-RN	Q	X	X	X	5,89E-02	2,63E-04
	ENF [occ/year]	X	X	X	3,79E+00	1,66E-02
	Downtime [h/year]	X	X	X	5,16E+02	2,31E+00
	Average Downtime [h]	X	X	X	1,36E+02	1,39E+02
8-1-MOCO-RN	Q	X	X	X	1,84E-02	8,10E-05
	ENF [occ/year]	X	X	X	1,35E+00	5,91E-03
	Downtime [h/year]	X	X	X	1,61E+02	7,10E-01
	Average Downtime [h]	X	X	X	1,20E+02	1,20E+02
LNG	Q	2,75E-03	5,58E-03	1,23E-05	X	1,76E-04
	ENF [occ/year]	2,49E-01	2,11E+00	2,16E-03	X	4,60E-02
	Downtime [h/year]	2,40E+01	4,88E+01	1,08E-01	X	1,54E+00
	Average Downtime [h]	9,64E+01	2,31E+01	4,99E+01	X	3,36E+01

Source: Fioravanti et al., 2019.

Table 10. 24h Logistic Delay Time: Unavailability (Q), Expected Number of Failures (ENF), Downtime [h/year], Average Downtime [h].

Corrective + Preventive Maintenance – 24 hr Logistic Delay Time						
Typical	**Parameter**	**Damage Class (nominal flow percentage)**				
		66%	**50%**	**33%**	**Bypass**	**0%**
1: N-TUCO-RP	Q	X	3,46E-02	X	1,39E-03	6,58E-06
	ENF [occ/year]	X	5,07E+00	X	2,65E-01	1,31E-03
	Downtime [h/year]	X	3,03E+02	X	1,22E+01	5,76E-02
	Average Downtime [h]	X	5,96E+01	X	4,59E+01	4,39E+01
1a: 4-TUCO-RP	Q	5,52E-02	X	1,32E-03	1,08E-03	4,76E-08
	ENF [occ/year]	8,12E+00	X	3,65E-01	1,67E-01	7,35E-06
	Down Time [h/year]	4,84E+02	X	1,16E+01	9,46E+00	4,17E-04
	Average Down Time [h]	5,96E+01	X	3,17E+01	5,67E+01	5,67E+01
2: N-MOCO-RP	Q	X	3,67E-03	X	6,96E-04	3,07E-07
	ENF [occ/year]	X	4,99E-01	X	1,06E-01	4,69E-05
	Downtime [h/year]	X	3,21E+01	X	6,09E+00	2,69E-03
	Average Downtime [h]	X	6,44E+01	X	5,76E+01	5,73E+02
2a: 4-MOCO-RP	Q	5,94E-03	X	5,09E-05	7,72E-04	3,38E-08
	ENF [occ/year]	8,06E-01	X	1,32E-02	1,14E-01	5,01E-06
	Downtime [h/year]	5,20E+01	X	4,46E-01	6,76E+00	2,96E-04
	Average Downtime [h]	6,46E+01	X	3,38E+01	5,93E+01	5,91E+01
3: 2-TUCO-RN	Q	X	1,31E-01	X	5,77E-03	2,54E-05
	ENF [occ/year]	X	7,44E+00	X	4,94E-01	2,16E-03
	Downtime [h/year]	X	1,14E+03	X	5,06E+01	2,22E-01
	Average Downtime [h]	X	1,54E+02	X	1,02E+02	1,03E+02

(Table 10 continues next page)

Table 10 (cont.) 24h Logistic Delay Time: Unavailability (Q), Expected Number of Failures (ENF), Downtime [h/year], Average Downtime [h].

Corrective + Preventive Maintenance – 24 hr Logistic Delay Time						
Typical	**Parameter**	**Damage Class (nominal flow percentage)**				
		66%	**50%**	**33%**	**Bypass**	**0%**
4: 2-MOCO-RN	Q	X	4,24E-02	X	5,77E-03	2,54E-05
	ENF [occ/year]	X	2,56E+00	X	4,94E-01	2,16E-03
	Downtime [h/year]	X	3,72E+02	X	5,06E+01	2,22E-01
	Average Downtime [h]	X	1,45E+02	X	1,02E+02	1,03E+02
5: 2-TUCO-RT	Q	X	X	X	1,14E-03	5,02E-06
	ENF [occ/year]	X	X	X	1,40E-01	6,14E-04
	Downtime [h/year]	X	X	X	1,00E+01	4,39E-02
	Average Downtime [h]	X	X	X	7,15E+01	7,15E+01
6: 2-MOCO-RT	Q	X	X	X	2,31E-03	1,22E-05
	ENF [occ/year]	X	X	X	3,33E-01	1,77E-03
	Downtime [h/year]	X	X	X	2,02E+01	1,07E-01
	Average Downtime [h]	X	X	X	6,06E+01	6,05E+01
7-1-TUCO-RN	Q	X	X	X	6,81E-02	3,06E-04
	ENF [occ/year]	X	X	X	3,80E+00	1,66E-02
	Downtime [h/year]	X	X	X	5,96E+02	2,68E+00
	Average Downtime [h]	X	X	X	1,57E+02	1,61E+02
8-1-MOCO-RN	Q	X	X	X	2,19E-02	9,64E-05
	ENF [occ/year]	X	X	X	1,36E+00	5,94E-03
	Downtime [h/year]	X	X	X	1,92E+02	8,45E-01
	Average Downtime [h]	X	X	X	1,41E+02	1,42E+02
LNG	Q	3,48E-03	1,12E-02	1,95E-05	X	3,08E-04
	ENF [occ/year]	2,54E-01	2,13E+00	2,73E-03	X	5,40E-02
	Downtime [h/year]	3,05E+01	9,83E+01	1,71E-01	X	2,70E+00
	Average Downtime [h]	1,20E+02	4,61E+01	6,25E+01	X	5,01E+01

Source: Fioravanti et al., 2019.

Table 11. 168h Logistic Delay Time: Unavailability (Q), Expected Number of Failures (ENF), Downtime [h/year], Average Downtime [h].

Corrective + Preventive Maintenance – 168 hr Logistic Delay Time						
Typical	**Parameter**	**Damage Class (nominal flow percentage)**				
		66%	**50%**	**33%**	**Bypass**	**0%**
1: N-TUCO-RP	Q	X	1,16E-01	X	8,06E-03	4,09E-05
	ENF [occ/year]	X	5,62E+00	X	5,45E-01	2,90E-03
	Downtime [h/year]	X	1,02E+03	X	7,06E+01	3,59E-01
	Average Downtime [h]	X	1,81E+02	X	1,30E+02	1,24E+02
1a: 4-TUCO-RP	Q	1,66E-01	X	1,33E-02	4,07E-03	1,83E-05
	ENF [occ/year]	9,01E+00	X	1,20E+00	2,07E-01	9,70E-04
	Down Time [h/year]	1,45E+03	X	1,17E+02	3,57E+01	1,60E-01
	Average Down Time [h]	1,61E+02	X	9,71E+01	1,72E+02	1,65E+02
2: N-MOCO-RP	Q	X	1,28E-02	X	2,52E-03	1,13E-05
	ENF [occ/year]	X	5,68E-01	X	1,16E-01	5,25E-04
	Downtime [h/year]	X	1,12E+02	X	2,21E+01	9,86E-02
	Average Downtime [h]	X	1,97E+02	X	1,91E+02	1,88E+02
2a: 4-MOCO-RP	Q	2,15E-02	X	5,81E-04	2,65E-03	1,16E-05
	ENF [occ/year]	9,96E-01	X	4,67E-02	1,15E-01	5,04E-04
	Downtime [h/year]	1,88E+02	X	5,09E+00	2,32E+01	1,02E-01
	Average Downtime [h]	1,89E+02	X	1,09E+02	2,02E+02	2,02E+02
3: 2-TUCO-RN	Q	X	2,26E-01	X	1,90E-02	8,41E-05
	ENF [occ/year]	X	7,44E+00	X	9,07E-01	3,97E-03
	Downtime [h/year]	X	1,98E+03	X	1,67E+02	7,37E-01
	Average Downtime [h]	X	2,66E+02	X	1,84E+02	1,86E+02

(Table 11 continues next page)

Table 11 (cont.) 168h Logistic Delay Time: Unavailability (Q), Expected Number of Failures (ENF), Downtime [h/year], Average Downtime [h].

Corrective + Preventive Maintenance – 168 hr Logistic Delay Time						
Typical	**Parameter**	**Damage Class (nominal flow percentage)**				
		66%	**50%**	**33%**	**Bypass**	**0%**
4: 2-MOCO-RN	Q	X	8,11E-02	X	4,10E-03	1,80E-05
	ENF [occ/year]	X	2,56E+00	X	1,92E-01	8,41E-04
	Downtime [h/year]	X	7,11E+02	X	3,59E+01	1,58E-01
	Average Downtime [h]	X	2,77E+02	X	1,87E+02	1,88E+02
5: 2-TUCO-RT	Q	X	X	X	5,71E-02	3,24E-04
	ENF [occ/year]	X	X	X	2,63E+00	1,48E-02
	Downtime [h/year]	X	X	X	5,00E+02	2,84E+00
	Average Downtime [h]	X	X	X	1,90E+02	1,92E+02
6: 2-MOCO-RT	Q	X	X	X	8,27E-03	4,35E-05
	ENF [occ/year]	X	X	X	3,87E-01	2,02E-03
	Downtime [h/year]	X	X	X	7,24E+01	3,81E-01
	Average Downtime [h]	X	X	X	1,87E+02	1,89E+02
7-1-TUCO-RN	Q	X	X	X	1,22E-01	5,59E-04
	ENF [occ/year]	X	X	X	3,84E+00	1,68E-02
	Downtime [h/year]	X	X	X	1,07E+03	4,90E+00
	Average Downtime [h]	X	X	X	2,79E+02	2,91E+02
8-1-MOCO-RN	Q	X	X	X	4,34E-02	1,93E-04
	ENF [occ/year]	X	X	X	1,40E+00	6,15E-03
	Downtime [h/year]	X	X	X	3,80E+02	1,69E+00
	Average Downtime [h]	X	X	X	2,71E+02	2,75E+02
LNG	Q	8,28E-03	4,61E-02	1,04E-04	X	1,60E-03
	ENF [occ/year]	2,84E-01	2,27E+00	6,54E-03	X	1,04E-01
	Downtime [h/year]	7,26E+01	4,03E+02	9,12E-01	X	1,41E+01
	Average Downtime [h]	2,55E+02	1,78E+02	1,39E+02	X	1,35E+02

Source: Fioravanti et al., 2019.

The results above lend themselves to interpolation for other logistic delay times and are particularly useful bearing in mind that most accidents and failures in compressor stations are not caused by a single incident of equipment malfunction or operator failure but are generally a result of a chain of events and errors that interact and/or accumulate to lead to a catastrophic failure. These failure events are extremely difficult to predict using the common single-degree-of-freedom analysis as they are caused by multiple factors and events that are systematically related to each other (Moore et al. 2003).

6 Pipelines

Pipelines are the most frequently used mean for transporting gas over long distances. Pipelines are only displaced by LNG cargoes for very long distances, particularly when sources and consumption areas are separated by seas or oceans (Qatar – Europe, Nigeria – Europe or USA – Europe, for example), and for destination flexibility reasons. Normally, natural gas, as it is when extracted from reservoirs, is not suitable for pipeline transportation or commercial use before being processed. Pipelines set their specifications for the specific quality of natural gas. In any case, natural gas must be processed in order to remove unwanted water vapour, solids, or other contaminants and to get those hydrocarbons that have a higher value as separate products.

Pipelines designed to transport gas over long distances are always made of steel in order to stand the high pressure required to make effective and efficient such transport. Typically they are divided in two types: Transit and transmission pipelines. Transit pipelines are designed for transporting natural gas over very long distances, crossing several countries and having few connection points with national systems, and are sometimes operated by operators other than the ones of the countries that they cross. Transmission pipelines are designed to transport gas over long distances within a country. Transit pipelines typically operate at very high pressure, higher in general than transmission pipelines. Along the pipelines compressor stations are located to pressurise gas and push it efficiently, and valves are used to isolate sections and re-direct flows conveniently. Pipelines play also an important role as gas storages that provide intra-day flexibility. Pushing gas into a network when there is not much consumption increases the quantity of gas in the system and increases its average pressure. This gas is readily available when consumption increases.

Unfortunately, pipelines, like any other element of the natural gas network, are subject to contingencies of different types, produced by different causes such as corrosion, external interference, as for example due to digging works, and construction defects, among others. In this section we put the focus on incidents that may take place in the natural gas transit and transmission pipelines, and on the best available data sources for estimating failure probabilities of those pipelines in the European Union.

6.1 The EGIG database on Gas Pipeline Incidents

Seventeen European gas transmission operators of fifteen countries (fourteen EU MS and Switzerland; originally, when the group started activities, only six operators) have been collecting data concerning incidents in gas transmission and transit natural gas pipelines since 1970, although the group formally started operating as such in 1982. The size of the operated network when the Group was established was around 30,000 km, and it has grown over the years to a size slightly above 140,000 km due to the natural development of the network and to the increase in the number of partners. The European Gas pipeline Incident data Group (EGIG) has published so far 10 reports summarizing the main statistics and findings, although it does not make public the raw data. The last one, the 10th EGIG reports covers the period 1970 – 2016. This section provides a summary of the most relevant information in that report (EGIG 2018) and the way to use it.

These reports, and particularly the last one, provide the best available aggregated information about failures in the European natural gas transport pipeline system. The members of the group report all sort of incidents that involve unintentional gas releases from pipes that are made of steel, onshore, work at a Maximum Operational Pressure (MOP) of 15 barg and are located outside the boundaries of facilities (thus no incident is reported from pipelines inside the limits of facilities such as LNG regasification terminals or compressor stations). Moreover, incidents are not reported either if the pipelines are in gas production lines or associated to components such as valves, regulators, etc.

Figure 13 shows the age of the pipelines in the reporting network per reporting year and per age segment. A few comments con be made on this picture. Firstly, the vast majority of the reporting network was deployed between 1964 and 2003, with the period 1964-1973 as the one when the reported network increased the most. A significant fraction of the network, larger than 10,000 km, was older than 53 years (deployed before 1964) by the time of the last reporting year (2016). A small fraction was even older than 63 years.

The designed reporting system involves useful information about the pipelines where the incident takes place, such as the diameter, operational pressure, wall thickness and year of construction, among others. Probably the most useful information reported is related two characteristics of the incidents: 1) the size of the associated leak, and 2) the initial cause of the incident.

The size of the associated leak is classified in three groups:

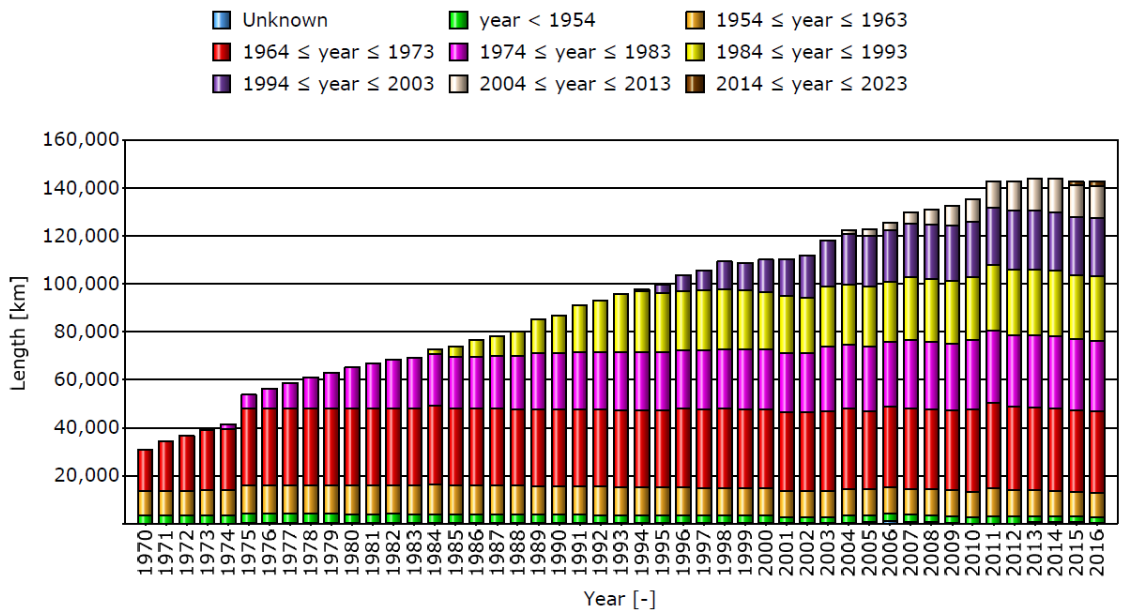
- Pinhole/crack: hole with an effective diameter smaller or equal to 2 cm.
- Hole: hole with an effective diameter larger than 2 cm and smaller or equal to the pipe diameter.
- Rupture: hole with a diameter larger than the pipeline diameter.

The initial cause of the incident is classified in the following five types:

- External interference.
- Corrosion.
- Construction defect / material failure
- Ground movement
- Other / unknown

Over the years the Group has accumulated empirical evidence about the gas network system. One way to measure this experience, which in statistical terms is equivalent to the sample size, is the exposure of the system. The exposure is obtained by multiplying the length of the network (km) by the time during which it has been in service (yr). This operation / measure may be calculated for all or for any part of the network, as for example for all pipelines with a diameter below 17'' (17 inches). In the first case it is called total system exposure, in the second case it is called partial system exposure. At the time of the publication of the 10th EGIG report, the total system exposure accumulated over the entire period of data collection (1970-2016) was of 4.41 x 106 km·yr. This value is obtained by adding the heights of all the bars in Figure 13.

Figure 13 - Length of the reporting network per year of construction and reporting year.



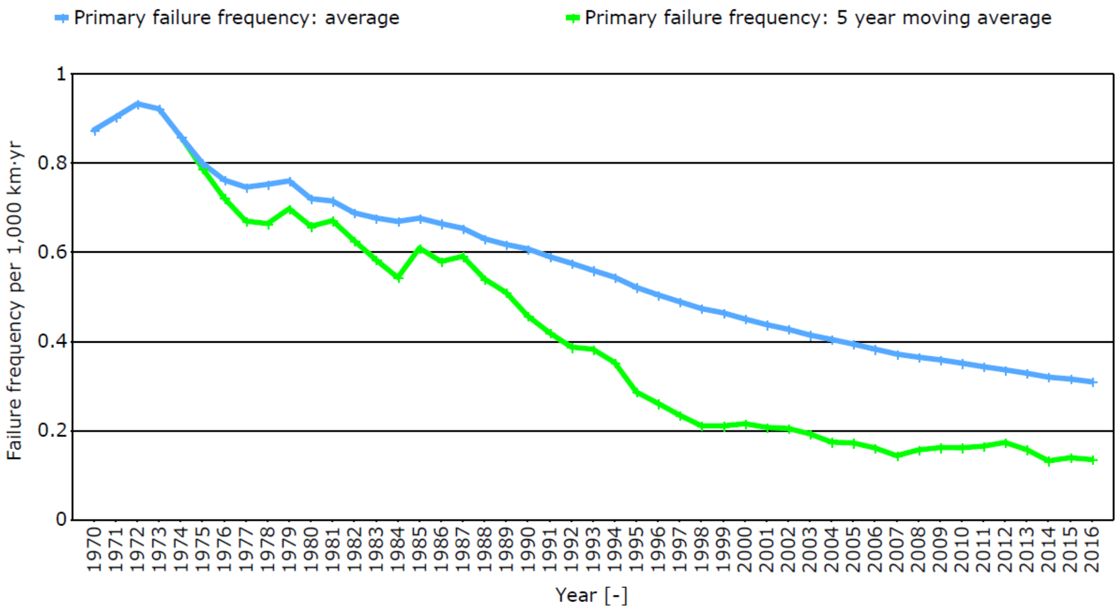
Source: 10th EGIG report (EGIG 2018).

6.2 Pipeline failure frequency

The main measure of reliability of the network, or of a part of it, is the failure frequency, which is the ratio between the number of failures in a period of time and the exposure of (part of) the network associated to that period. The failure frequency may be estimated for different categories (cause of the incident, size of the leak, etc.), and for different time periods. Failure frequencies are called "Primary" if they refer to the entire network and "Secondary" if they refer only to a part of the network.

Figure 14 shows the evolution of the Primary failure frequency for the entire period (until each specific time) and for 5-year rolling windows. The ordinates of the blue curve are calculated by dividing the number of incidents until a given year (included) by the total system exposure until that year (included). The ordinates of the green curve are calculated by dividing the number incidents in the last five years for each year (the year considered and the four years before) by the total system exposure in those five years. By definition, the ordinates of the green curve can be computed only starting in 1974. Both curves start to diverge in 1975. Both curves show a steady decrease of the failure frequency over time. This decrease is certainly related to the improvement of maintenance practices, the development of anticorrosion technologies as for example cathodic protection, and the obligation in some countries to digitalise the gas transmission network layout and the obligation to consult this information before initiating any digging works.

Figure 14 - Evolution of the Primary failure frequency over time.



Source: 10th EGIG report (EGIG 2018).

Table 12 provides, most likely, the most interesting information for a general practitioner of Risk Assessments of gas networks. It contains six periods of reference (first column) and for each of these periods, we can see the number of incidents (third column), the total system exposure (fourth column) and the Primary failure frequency per 1,000 km and yr for each corresponding period (fifth column). Additionally, the second column provides the length in years of each period.

When performing a Risk Assessment of a gas transmission network, it is important to know probabilities like the probability of having a failure in a given pipeline with a given length along a period of one year, or knowing the expected number of pipeline failures in the entire, or part of a, gas network. In the first case we would proceed in the following manner. Let us assume that we are analysing the case of a 200 km long pipeline. The failure frequency for such a pipeline may be estimated as

$$F_{200\ km} = 0.000165\ km^{-1} yr^{-1} \cdot 200\ km = 0.033\ yr^{-1}$$

This frequency may be taken as our best estimate of the probability of failure per year for the mentioned pipeline. For this estimation we have used the primary failure frequency correspoinding to period 2007-2011.

Regarding the second case, let us asume thet the network under study is 20,000 km long. If we want to know what is the expected number of failures per year in such a network, we follow the same procedure, obtaining a best estimate of

$$N_{20000\ km} = 0.000165\ km^{-1} yr^{-1} \cdot 20000\ km = 3.3\ failures\ yr^{-1}$$

Table 12. Primary failure frequencies over different time periods.

Period	Interval [years]	Number of incidents	Total system exposure – 10^3 km·yr	Primary failure frequency per 10^3 km·yr
1970-1976	7 years	223	290	0.768
1977-1986	10 years	420	680	0.618
1987-1996	10 years	305	910	0.335
1997-2006	10 years	210	1,140	0.184
2007-2011	5 years	111	674	0.165
2012-2016	5 years	97	716	0.136

Source: JRC based on Table 9 of 10th EGIG report (EGIG 2018).

If we observe the table, we will see that values are reported for six successive, non-overlapping periods of different time length (7, 10, 10, 10, 5 and 5 years). The last column, which provides the result of dividing the values in the third column by values in the fourth column, shows that the actual failure frequencies have dramatically decreased over time. Nevertheless, this is a subjective appreciation that has to be confirmed with some statistical tests. We have proceeded in a similar manner as we did with the incidents in the LNG terminals (see page 33, footnote 4). Firstly we compared periods 1970-1976 and 1977-1986, 1977-1986 and 1987-1996, and 1987-1996 and 1997-2006. Among these three tests, the first delivered a P-value of 0.016, and the other two were smaller than 10^{-4} which indicate clearly significant statistical differences between the four periods considered. Thus, the significance of the decrease in the period 1970-2006 is confirmed. Then we made the corresponding tests among the periods 1997-2006 and 2007-2011, 2007-2011 and 2016, and 1997-2006 and 2011-2016. In these cases we found the corresponding P-values of 0.36, 0.16 and 0.014. If we adopt the typical threshold of 0.05, we conclude that there are statistically significant differences between periods 1997-2006 and 2011-2016, but not among the other two groups of periods. In this situation of steady slow decrease, where the failure frequencies of both extreme time periods are different of each other, but not different any of them from the failure frequency for the intermediate period, it is not easy either to suggest a single value as best estimate representative of nowadays situation. One possibility would be to take as best estimate the value 0.165, and values 0.136 and 0.184 as optimistic and pessimistic estimates respectively. See Annex 4 for details on all these tests of hypothesis.

As in the case of LNG terminals GIIGNL database, we have not had access to the original data, only to the aggregated results presented in the 10th EGIG report. This precludes any analysis of the homogeneity of spread of incidents over the length of the pipelines, which could help identifying reporting networks that have either higher or lower frequencies of failures than average. In the absence of this information, the estimates suggested in the previous paragraph are reasonable for a generic European pipeline. One more point to stress is that a substantial fraction of the European national networks do not report to EGIG. In the case of operators of those networks, they should be careful before using these estimates and should check if reported data are representative for the situation of their networks. Finally, the authors of this document find the EGIG reports very useful and encourage transmission system operators of European networks to start data collection and reporting.

7 Conclusions

According to Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply, Member States have to develop their national gas risk assessments and contribute to the regional risk assessments of the Risk Groups they are included in. These activities demand the collection of a large quantity of information about key facilities of the concerned countries, their operation, failure modes and, whenever possible, probabilities of failure. This study is a modest contribution to provide some of this information to EU Member States that have to meet these obligations of the Regulation.

In this report we have performed a review of the main facilities of the EU gas transmission network. We have addressed LNG regasification terminals, UGS facilities, compressor stations and pipelines. In some cases we have done an inventory of facilities, as it is the case of UGS and LNG facilities, although in other cases like the one of compressor stations we have focused on a significant number of them which has allowed us to extract some information of interest to use in RAs.

Regarding UGS facilities, we have provided a picture of the existing types (aquifers, depleted files and salt caverns), their key components and characteristics. Annex I contains an inventory of these facilities in the EU. We have also identified information from two surveys that allow to provide failure frequencies for wells and for storage cavities. Failure frequencies per site or well are in the range $8.3 \cdot 10^{-6}$ - $6 \cdot 10^{-3}$ yr^{-1}.

Regarding LNG facilities, we have identified main types of facilities (on-shore, and off-shore of three types: gravity based structure, floating storage and regasification unit, and transport and regasification vessel). We have also shown the way these terminals operate and have provided an inventory of terminals in the EU (see Annex II) and a short summary of each facility. Main initiating events of failures have been identified, typically related to the unloading of LNG from the vessel, the LNG tanks loading and unloading and the actual storage, the recondenser and vaporizer section, the boil-off recovery, the send-out and also external sources. The analysis of incidents recorded in a project developed by GIIGNL in the period 1965-2007 has allowed us to suggest failure rates per site in the range 0.14 – 0.45 yr^{-1} with a central estimate of 0.25 yr^{-1}.

The work done on Compressor Stations has allowed us to show the main types, characteristics and operation of these facilities. This has been the case where a real inventory has been completely impossible due to the lack of exhaustive public and commercial information. Nevertheless, a number of frequent types of compressor stations (8 types in total) has been identified in a recent study and reported in this document. The study mentioned reports for each type of compressor station the different possible damage states in terms of remaining CS capacity (2/3 capacity, 50% capacity, 1/3 capacity, bypass and 0% capacity). Key reliability parameters are provided for each CS type, damage state and for three different logistic delays (one hour, one day and one week): the unavailability (yr^{-1}), the expected number of incident per year, the downtime ($h \cdot yr^{-1}$), and the average downtime (h). Interpolations of the four reliability magnitudes are possible for different logistic times between one hour and one week.

Finally, a summary of the main types of failures of pipelines (transmission lines with maximum operating pressure above 15 barg) and likely reasons has been provided. The analysis of some of the information in the 10^{th} EGIG report has also allowed us to provide some advice about reasonable failure frequencies of pipelines. The failure frequencies per 1,000 km of pipeline range suggested is 0.136 – 0.184 yr^{-1}, with a central value of 0.165 yr^{-1}.

References

Acton, A., Brown, D. and Langry, P. LNG incident identification – updated compilation and analysis by International Group of LNGF Importers (GIIGNL).

Berest, P. and Brouard, B., Safety of salt caverns used for underground storage, Oil & Gas Science and Technology – Rev. IFP, Vol. 58, No. 3, pp. 361-384, 2003.

Bloch and Geitner, Compressors: How to Achieve High Reliability & Availability. McGraw-Hill, 2012.

Boyce, Gas Turbine Engineering Handbook - 4th Edition. Butterworth-Heinemann (Elsevier), 2011.

Bulte, A., An innovative solution for fixed offshore LNG regasification Terminals, 2017

Chudoba, Reliability Data Estimation Study. Corporate Report, 2014.

European Commission, REGULATION (EC) No 715/2009 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 July 2009 on conditions for access to the natural gas transmission networks

European Commission, 2015. REPORT on the role of gas storage in internal market and in ensuring security of supply, Directorate-General for Energy. Directorate B-Internal Energy Market. Unit B2.

European Gas pipeline Incident data Group (EGIG). 10th report of the European Gas pipeline Incident data Group. Doc. Number VA 17.R.0395. March 2018.

Evans, D.J., An appraisal of underground gas storage technologies and incidents, for the development of risk assessment methodology. British Geological Survey Internal Report, 2007.

Evans, D. J., Analysis of occurrences at underground fuel storage facilities and assessment of the main mechanisms leading to loss of storage integrity. 51st US Rock Mechanics / Geomechanics Symposium. ARMA 17-265, 2017.

Fioravanti, G. De Simone, A. Carpignano, A. Ruzzone, G. Mortarino, M. Piccini, H. Calisto (ed.), V. Kopustinskas (ed.), R. Bolado-Lavín (ed.). Compressor Station Facility Failure Modes: Causes, Taxonomy and Effects, EUR 30265 EN, Luxembourg, Publications Office of the European Union, 2020, ISBN 978-92-76-19810-9, doi: 10.2760/67609, JRC120149.

Gas Infrastructure Europe (2019a). LNG Map - Existing and Planned Infrastructure 2019.

Gas Infrastructure Europe (2019b). LNG Map Database - May 2019.

Haug, A. K., R. Eie, et al. (2003). Offshore Concrete Structures for LNG facilities – New developments 2003 Offshore Technology Conference. Houston, Texas, USA.

HSE, Failure rates for underground gas storage. Report prepared by the Health and Safety Laboratory for the Health and Safety Executive, 2008.

Khan, M. (2018). "Comparative Well-to-Tank energy use and greenhouse gas assessment of natural gas as a transportation fuel in Pakistan." Energy for Sustainable Development 43: 38-59.

King & Spalding (2018) An Overview of LNG Import Terminals in Europe.

Kurz and Lubomirsky, Concepts in Gas Compressor Station Configuration. Paper IPTC 14424. International Petroleum Technology Conference, Bangkok, Thailand, 15–17 November 2011.

Kutrowski, E. Jager, R. Kuik, A. Cappanera, M. Negretti, A. Castellaneta, R. Ferraris, E. Freitag, C. Fleury, M. Madoui–Barmasse, S. Cervoni. A Common Approach for Assessing the Safety of Natural Gas Compressor Stations. 23rd World Gas Conference, Amsterdam, 2006.

IEA (2018). World Energy Outlook 2018, IEA, Paris.

iNTeg-Risk project (2011a). Reference solution containing documents, methods and tools, for the assessment and management of emerging risks related to new and intensified technologies available for LNG regasification terminals, iNTeg-Risk project.

iNTeg-Risk project (2011b). Annex 4 of Reference solution containing documents, methods and tools, for the assessment and management of emerging risks related to new and intensified technologies available for LNG regasification terminals, iNTeg-Risk project.

iNTeg-Risk project (2011c). Annex 9 of Reference solution containing documents, methods and tools, for the assessment and management of emerging risks related to new and intensified technologies available for LNG regasification terminals, iNTeg-Risk project.

International Group of Liquified Natural Gas Importers (2014). The LNG process chain.

Mohitpour, M., Botros, K. K., Van Hardeveld, T., Pipeline Pumping and Compression Systems: A Practical Approach. ASME Press, 2008.

Mokhatab, S., Poe, W. A, Mak J. Y., *Handbook of natural gas transmission and processing. Principles and practices*, 4th Edition, Gulf Professional Publishing, 2019.

Moore, T. Z., K. C. Kozak, K. Brun, A. Ramos-Aparicio. Risk, Reliability and Failure Mode Analysis. Paper PSIG 0701. PSIG Annual Meeting. Calgary, Alberta, 24 October – 26 October 2007.

Ohanian, S. and Kurz, R., Series or Parallel Arrangement in a Two-Unit Compressor Station. ASME Journal of Engineering for Gas Turbines and Power 124(4): 936-941, 2002.

OREDA, Offshore Reliability Data. Det Norske Veritas, Norway, 2014.

PHMSA, Pipeline and Hazardous Materials Safety Administration. Natural Gas Transmission Incident Data. Retrieved from http://www.phmsa.dot.gov/pipeline/library/data-stats, 2014.

Pillon, F. J., Romano, C. D., Cocco, F. H., Natural Gas Compression Stations - Compressors out of service distribution function. Analysis and evaluation. Paper PSIG 0506. PSIG Annual Meeting. San Antonio, Texas, 7 November – 9 November 2005.

Tek, M. R., Natural gas underground storage: inventory and deliverability. Penn Well, 1997.

Songhurst, B., The Outlook for Floating Storage and Regasification Units (FSRUs) Oxford Institute for Energy Studies, 2017.

Stopa, J. and Kosowski P., Underground gas storage in Europe - energy safety and its cost, 27th World Gas Conference, Washington DC, 2018.

Vianello, C. and G. Maschio, Risk Analysis of LNG Terminal: Case Study. Chemical Engineering Transactions 36, 2014.Zubaryeva, A., Dilara, P. and Maineri, L., *Publicly funded research, development and demonstration projects on electric and plug-in vehicles in Europe — update*, EUR 27149, Publications Office of the European Union, Luxembourg, 2015, doi:10.2790/271951.

List of abbreviations and definitions

bcm	Billion Cubic Metres
BOG	Boil-Off Gas
CS	Compressor Station
ENF	Expected Number of Failures
EU	European Union
FSRU	Floating Storage and Regasification Unit
GBS	Gravity-Based Structure
GHG	Greenhouse Gases
HAZID	HAZard IDentification
HP	High Pressure
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gases
MOCO	Motocompressor
MS	Member State
NGL	Natural Gas Liquids
OPV	Open Rack Vaporiser
RA	Risk Assessment
RN	Null Redundancy
RP	Partial Redundancy
RT	Total Redundancy
THT	Tetrahydrothiophene
TRV	Transport and Regasification Vessel
TSO	Transmission System Operators
TUCO	Turbocompressor
UGS	Underground Gas Storage

List of figures

List of tables

Annexes

Annex 1. Inventory of UGS facilities of Europe

Table A.1. Inventory of EU UGS facilities.

Country	Facility/Location	Type	Operator	Status	Working gas (technical) TWh	Withdrawal technical capacity GWh/day	Injection technical capacity GWh/day	Access regime
Austria	Haidach	Depleted field	Astora	operational	10.44	104.59	90.16	nTPA
	Haidach	Depleted field	GSA	operational	19.99	198.18	177.60	nTPA
	Schönkirchen/Reyersdorf	Depleted field	OMV Gas Storage	operational	20.72	260.35	176.28	nTPA
	Tallesbrunn	Depleted field	OMV Gas Storage	operational	4.52	43.39	33.90	nTPA
	VGS OMV Gas Storage Pool	Depleted field	OMV Gas Storage	operational	25.24	303.74	210.18	nTPA
	Aigelsbrunn	Depleted field	RAG.Energy.Storage	operational	1.47	13.58	13.58	nTPA
	Haidach 5	Depleted field	RAG.Energy.Storage	operational	0.18	5.42	5.42	nTPA
	Nussdorf/Zagling	Depleted field	RAG.Energy.Storage	operational	3.26	40.73	32.64	nTPA
	Puchkirchen/Haag	Depleted field	RAG.Energy.Storage	operational	12.22	141.10	141.10	nTPA
	RAG Storage (storage group)	Depleted field	RAG.Energy.Storage	operational	17.12	200.84	192.75	nTPA
	7 Fields	Depleted field	Uniper Energy Storage	operational	19.42	242.69	161.81	nTPA
Belgium	Loenhout	Aquifer	Fluxys	operational	9.00	169.5	88.14	rTPA
Bulgaria	Chiren	Depleted field	Bulgartransgaz	operational	6.27	36.20	34.10	rTPA
Croatia	Okoli	Depleted field	PSP	operational	5.81	60.57	45.43	rTPA
Czech Republic	Dolni Dunajovice	Depleted field	innogy Gas Storage	operational	0	0	0	nTPA
	Háje	Other	innogy Gas Storage	operational	0	0	0	nTPA
	Lobodice	Aquifer	innogy Gas Storage	operational	0	0	0	nTPA
	Štramberk	Depleted field	innogy Gas Storage	operational	0	0	0	nTPA
	Třanovice	Depleted field	innogy Gas Storage	operational	0	0	0	nTPA
	Tvrdonice	Depleted field	innogy Gas Storage	operational	0	0	0	nTPA

Country	Facility/Location	Type	Operator	Status	Working gas (technical) TWh	Withdrawal technical capacity GWh/day	Injection technical capacity GWh/day	Access regime
	VGS innogy virtual storage (storage group)	Other	innogy Gas Storage	operational	28.71	422.29	315.50	nTPA
	Uhřice	Depleted field	MND Gas Storage	operational	3.08	107.21	57.67	nTPA
	Dambořice	Depleted field	Moravia Gas Storage	operational	2.61	78.20	46.92	nTPA
	Dolni Bojanovice	Depleted field	SPP Storage	operational	6.12	95.58	74.34	nTPA
Denmark	Lille Torup	Salt cavern	Gas Storage Denmark	operational	0	0	0	nTPA
	Stenlille	Aquifer	Gas Storage Denmark	operational	0	0	0	nTPA
	VGS GSD gas storage	Aquifer	Gas Storage Denmark	operational	10.35	194.40	100.80	nTPA
France	Saline: Etrez	Salt cavern	Storengy	operational	0	0	0	nTPA
	Saline: Manosque	Salt cavern	Storengy	operational	0	0	0	nTPA
	Saline: Tersanne/Hauterives	Salt cavern	Storengy	operational	0	0	0	nTPA
	VGS Storengy Saline	Salt cavern	Storengy	operational	12.2	642.00	136.00	nTPA
	SEDIANE: Beynes Profond	Aquifer	Storengy	operational	0	0	0	nTPA
	SEDIANE: Beynes Supérieur	Aquifer	Storengy	operational	0	0	0	nTPA
	SEDIANE: Saint-Illiers-la-Ville	Aquifer	Storengy	operational	0	0	0	nTPA
	VGS Storengy Sediane	Aquifer	Storengy	operational	11.65	277.00	146.00	nTPA
	VGS SEDIANE B: Gournay-sur-Aronde	Aquifer	Storengy	operational	13.40	248.00	112.00	nTPA
	SEDIANE LITTORAL: Céré-la-Ronde	Aquifer	Storengy	operational	0	0	0	nTPA
	SEDIANE LITTORAL: Chémery	Aquifer	Storengy	operational	0	0	0	nTPA
	VGS Storengy SEDIANE LITTORAL	Aquifer	Storengy	operational	33.20	416.00	260.00	nTPA
	SERENE Nord: Cerville	Aquifer	Storengy	operational	0	0	0	nTPA
	SERENE Nord: Germigny-sous-Coulombs	Aquifer	Storengy	operational	0	0	0	nTPA
	SERENE Nord: Saint-Clair-sur-Epte	Aquifer	Storengy	operational	0	0	0	nTPA

Country	Facility/Location	Type	Operator	Status	Working gas (technical) TWh	Withdrawal technical capacity GWh/day	Injection technical capacity GWh/day	Access regime
	SERENE Nord: Trois-Fontaines l'Abbaye	Depleted Field	Storengy	operational	0	0	0	nTPA
	VGS Storengy Serene Nord	Aquifer	Storengy	operational	16.65	222.00	139.00	nTPA
	SERENE SUD: Céré-la-Ronde	Aquifer	Storengy	operational	0	0	0	nTPA
	SERENE SUD: Chémery	Aquifer	Storengy	operational	0	0	0	nTPA
	VGS Storengy SERENE SUD	Aquifer	Storengy	operational	12.90	145.00	91.00	nTPA
	Izaute	Aquifer	TERÉGA	operational	0	0	0	nTPA
	Lussagnet	Aquifer	TERÉGA	operational	0	0	0	nTPA
	TERÉGA (storage group)	Aquifer	TERÉGA	operational	33.11	556.00	342.00	nTPA
Germany	Jemgum	Salt cavern	astora	operational	6.86	145.80	99.90	nTPA
	Rehden	Depleted field	astora	operational	48.62	530.4	344.76	nTPA
	Wolfersberg	Depleted field	BayernUGS	Operational	4.12	65.03	37.93	nTPA
	Etzel Crystal	Salt cavern	Crystal, Friedeburger Speicherbetriebsgesellschaft	Operational	2.42	94.08	54.00	nTPA
	Inzenham-West	Depleted field	DEA Speicher	Operational	4.77	80.64	53.76	nTPA
	Etzel EKB	Salt cavern	EKB (Etzel-Kavernenbetriebsgesellschaft)	Operational	11.20	216.96	122.04	nTPA
	Etzel	Salt cavern	EnBW Energie Baden-Württemberg	Operational	2.42	94.08	54.00	nTPA
	Epe Eneco	Salt cavern	Eneco	Operational	1.44	93.60	93.60	nTPA
	Frankenthal	Aquifer	Enovos Storage	Operational	0.89	26.64	6.47	nTPA
	Katharina	Salt cavern	Erdgasspeicher Peissen	Operational	1.82	0	0	nTPA
	EWE-Zone L (Nüttermoor/Huntorf)	Salt cavern	EWE Gasspeicher	Operational	9.47	246.96	91.73	nTPA
	Jemgum H	Salt cavern	EWE Gasspeicher	Operational	3.98	69.00	55.20	nTPA
	Nüttermoor H-1	Salt cavern	EWE Gasspeicher	Operational	1.83	69.60	48.72	nTPA
	Nüttermoor H-2	Salt cavern	EWE Gasspeicher	Operational	1.96	49.68	24.84	nTPA
	Nüttermoor H-3	Salt cavern	EWE Gasspeicher	Operational	2.69	82.08	41.04	nTPA

Country	Facility/Location	Type	Operator	Status	Working gas (technical) TWh	Withdrawal technical capacity GWh/day	Injection technical capacity GWh/day	Access regime
	Nüttermoor L	Salt cavern	EWE Gasspeicher	Operational	0.43	23.52	21.17	nTPA
	Rüdersdorf H	Salt cavern	EWE Gasspeicher	Operational	1.08	32.77	10.66	nTPA
	Etzel EGL	Salt cavern	Equinor Storage Deutschland	Operational	2.21	361.15	210.67	nTPA
	Empelde	Salt cavern	GHG - Gasspeicher Hannover	Operational	3.83	140.76	44.16	nTPA
	Etzel ESE	Salt cavern	Gas Union Storage	Operational	1.58	55.64	31.80	nTPA
	Reckrod	Salt cavern	Gas Union Storage	Operational	1.32	27.60	13.80	nTPA
	Kiel-Rönne	Salt cavern	Hansewerk	Operational	0.24	13.56	5.69	nTPA
	Kraak	Salt cavern	Hansewerk	Operational	2.97	107.52	48.38	nTPA
	Epe L-Gas	Salt cavern	innogy Gas Storage NWE	Operational	1.84	99.14	49.57	nTPA
	Epe NL	Salt cavern	innogy Gas Storage NWE	Operational	2.92	118.87	47.55	nTPA
	Stassfurt	Salt cavern	innogy Gas Storage NWE	Operational	7.29	175.27	83.59	nTPA
	Epe H-Gas	Salt cavern	innogy Gas Storage NWE	Operational	0	0	0	nTPA
	Xanten	Salt cavern	innogy Gas Storage NWE	Operational	0	0	0	nTPA
	VGS innEXpool	Salt cavern	innogy Gas Storage NWE	Operational	6.66	325.76	104.02	nTPA
	Epe KGE	Salt cavern	KGE (Kommunale Gasspeichergesellschaft Epe)	Operational	2.17	109.44	41.04	nTPA
	Hähnlein	Aquifer	MND Gas Storage Germany	Operational	0	0	0	nTPA
	Stockstadt	Aquifer	MND Gas Storage Germany	Operational	0	0	0	nTPA
	VSG MND GSG	Aquifer	MND Gas Storage Germany	Operational	2.43	61.03	37.97	nTPA
	Eschenfelden	Aquifer	N-ERGIE	Operational	0.23	162.88	52.01	nTPA
	Epe Nuon	Salt cavern	Nuon	Operational	3.01	141.81	70.80	nTPA
	Etzel ESE	Salt cavern	OMV Gas Storage Germany	Operational	5.30	106.80	71.28	nTPA
	Bruggraf-Bernsdorf	Salt cavern	Ontras Gastransport	Operational	0.03	0	0	No TPA
	Bremen-Lesum	Salt cavern	Stadtwerke Bremen (wesernetz)	Operational	0.86	4.14	1.38	nTPA
	Kiel-Rönne	Salt cavern	Stadtwerke Kiel	Operational	0.50	13.68	5.88	nTPA
	Bremen-Lesum	Salt cavern	Storengy Deutschland	Operational	1.60	52.01	24.82	nTPA
	Fronhofen-Trigonodus	Depleted field	Storengy Deutschland	Operational	0.12	8.03	5.35	nTPA

Country	Facility/Location	Type	Operator	Status	Working gas (technical) TWh	Withdrawal technical capacity GWh/day	Injection technical capacity GWh/day	Access regime
	Harsefeld	Salt cavern	Storengy Deutschland	Operational	1.24	81.72	24.67	nTPA
	Peckensen	Salt cavern	Storengy Deutschland	Operational	3.93	231.96	84.67	nTPA
	Schmidhausen	Depleted field	Storengy Deutschland	Operational	1.74	40.32	10.75	nTPA
	Uelsen	Depleted field	Storengy Deutschland	Operational	9.78	107.60	81.03	nTPA
	Allmenhausen	Depleted field	TEP (Thüringer Energie Speichergesellschaft)	Operational	0.71	17.11	8.56	nTPA
	Sandhausen	Aquifer	terranets bw	Operational	0.35	12.42	5.52	No TPA
	Etzel EGL	Salt cavern	Total Etzel Gaslager	operational	0.06	1.97	0.89	nTPA
	Epe Trianel	Salt cavern	TGE (Trianel Gasspeicher Epe)	operational	2.23	164.88	82.44	nTPA
	Bierwang	Depleted field	Uniper Energy Storage	operational	9.18	349.44	268.80	nTPA
	Breitbrunn	Depleted field	Uniper Energy Storage	operational	11.11	139.78	67.20	nTPA
	Epe Uniper H-Gas	Salt cavern	Uniper Energy Storage	operational	15.30	465.12	328.32	nTPA
	Epe Uniper L-Gas	Salt cavern	Uniper Energy Storage	operational	4.26	285.12	57.02	nTPA
	Eschenfelden	Aquifer	Uniper Energy Storage	operational	0.44	10.85	5.42	nTPA
	Etzel EGL	Salt cavern	Uniper Energy Storage	operational	11.32	271.68	155.68	nTPA
	Etzel ESE	Salt cavern	Uniper Energy Storage	operational	12.10	396.72	425.64	nTPA
	Etzel ESE	Salt cavern	VNG Gasspeicher	operational	1.40	46.17	28.73	nTPA
	Kirchheiligen	Depleted field	VNG Gasspeicher	operational	2.02	33.68	37.72	nTPA
	Bernburg	Salt cavern	VNG Gasspeicher	operational	0	0	0	nTPA
	Bad Lauchstädt	Salt cavern	VNG Gasspeicher	operational	0	0	0	nTPA
	Bad Lauchstädt	Depleted field	VNG Gasspeicher	operational	0	0	0	nTPA
	VGS storage hub	Other	VNG Gasspeicher	operational	23.49	496.15	294.97	nTPA
Hungary	Hajdúszoboszló	Depleted Field	Hungarian Gas Storage	operational	17.55	211.86	107.86	rTPA
	Kardoskút	Depleted Field	Hungarian Gas Storage	operational	3.00	31.03	23.01	rTPA
	Pusztaederics	Depleted Field	Hungarian Gas Storage	operational	3.64	31.03	30.82	rTPA
	Zsana	Depleted Field	Hungarian Gas Storage	operational	23.22	299.60	181.90	rTPA
	VGS MFGT	Depleted Field	Hungarian Gas Storage	operational	47.40	617.64	398.74	rTPA

Country	Facility/Location	Type	Operator	Status	Working gas (technical) TWh	Withdrawal technical capacity GWh/day	Injection technical capacity GWh/day	Access regime
	Szöreg-1	Depleted field	MMBF	operational	20.11	263.90	134.06	rTPA
Italy	Cellino	Depleted Field	Edison Stoccaggio	operational	0.03	0	0	rTPA
	Collalto	Depleted Field	Edison Stoccaggio	operational	0.21	37.00	20.09	rTPA
	Cotignola & San Potito	Depleted Field	Edison Stoccaggio	operational	0.24	56.04	61.53	rTPA
	VGS Edison Stoccaggio	Depleted Field	Edison Stoccaggio	operational	11.32	186.64	156.50	rTPA
	Bordolano	Depleted Field	STOGIT	operational	0	0	0	rTPA
	Brugherio	Depleted Field	STOGIT	operational	0	0	0	rTPA
	Cortemaggiore	Depleted Field	STOGIT	operational	0	0	0	rTPA
	Fiume Treste	Depleted Field	STOGIT	operational	0	0	0	rTPA
	Minerbio	Depleted Field	STOGIT	operational	0	0	0	rTPA
	Ripalta	Depleted Field	STOGIT	operational	0	0	0	rTPA
	Sabbioncello	Depleted Field	STOGIT	operational	0	0	0	rTPA
	Sergnano	Depleted Field	STOGIT	operational	0	0	0	rTPA
	Settala	Depleted Field	STOGIT	operational	0	0	0	rTPA
	VGS STOGIT	Depleted field	STOGIT	operational	183.68	2783.07	1582.53	rTPA
Latvia	Inčukalns	Aquifer	Conexus Baltic Grid	operational	24.15	315.00	178.50	rTPA
Netherlands	EnergyStock	Salt cavern	EnergyStock BV	operational	3.01	422.04	257.91	nTPA
	Grijpskerk	Depleted field	NAM	operational	27.67	719.33	172.92	No TPA
	Norg (Langelo)	Depleted field	NAM	operational	48.71	742.48	448.75	No TPA
	Bergermeer	Depleted field	TAQA Gas Storage	operational	45.65	554.20	387.36	nTPA
	Alkmaar	Depleted field	TAQA Piek Gas	operational	4.90	352.80	36.00	No TPA
Poland	Wierzchowice	Depleted Field	Gas Storage Poland	operational	13.2	105.60	67.20	rTPA
	Kosakowo	Salt cavern	Gas Storage Poland	operational	1.62	107.04	26.76	rTPA
	Mogilno	Salt cavern	Gas Storage Poland	operational	6.57	200.52	106.94	rTPA
	GSF Kawerna	Salt cavern	Gas Storage Poland	operational	8.19	307.56	133.70	rTPA

Country	Facility/Location	Type	Operator	Status	Working gas (technical) TWh	Withdrawal technical capacity GWh/day	Injection technical capacity GWh/day	Access regime
	Swarzow	Depleted Field	Gas Storage Poland	operational	1.01	10.40	11.20	rTPA
	Brzeznica	Depleted Field	Gas Storage Poland	operational	1.13	16.10	16.20	rTPA
	Strachocina	Depleted Field	Gas Storage Poland	operational	4.05	37.90	29.70	rTPA
	Husow	Depleted Field	Gas Storage Poland	operational	5.62	64.60	46.70	rTPA
	GSF Sanok	Salt cavern	Gas Storage Poland	operational	11.81	129.80	103.80	rTPA
	Bonikowo	Depleted Field	PGNiG	operational	2.30	27.60	19.32	No TPA
	Daszewo	Depleted Field	PGNiG	operational	0.35	4.37	2.76	No TPA
Portugal	Carriço	Salt Cavern	REN Armazenagen	operational	3.57	85.68	24.00	rTPA
Romania	Balanceanca	Depleted field	Depogaz Ploiești (ex Romgaz)	operational	0.55	13.18	10.98	rTPA
	Bilciuresti	Depleted field	Depogaz Ploiești (ex Romgaz)	operational	14.33	152.78	109.13	rTPA
	Cetatea de Balta	Depleted field	Depogaz Ploiești (ex Romgaz)	operational	0.32	1.05	0	rTPA
	Ghercesti	Depleted field	Depogaz Ploiești (ex Romgaz)	operational	1.63	21.40	21.40	rTPA
	Sarmasel	Depleted field	Depogaz Ploiești (ex Romgaz)	operational	9.60	79.04	68.50	rTPA
	Urziceni	Depleted field	Depogaz Ploiești (ex Romgaz)	operational	4.02	50.16	33.44	rTPA
	Târgu Mureş	Depleted field	Depomures	operational	3.15	30.00	19.00	rTPA
Slovakia	Láb complex	Depleted field	Nafta	operational	22.28	332.46	292.77	nTPA
	Gajary-Baden	Depleted field	Nafta	operational	6.36	74.25	49.13	nTPA
	Láb 4	Depleted field	Pozagas	operational	6.95	72.66	72.66	nTPA
Spain	Gaviota	Depleted Field	Enagas	operational	18.34	66.30	52.30	rTPA
	Marismas	Depleted Field	Enagas/Gas Natural Fenosa	operational	1.62	4.20	4.20	rTPA
	Serrablo	Depleted Field	Enagas	operational	9.73	79.10	44.20	rTPA
	Yela	Aquifer	Enagas	operational	2.29	64.90	25.60	rTPA
	VGS Enagas Basic UGS	Other	Enagas	operational	31.98	214.50	126.30	rTPA
Sweden	Skallen	Rock Cavern	Swedegas	operational	0.10	11.52	4.32	nTPA

Country	Facility/Location	Type	Operator	Status	Working gas (technical) TWh	Withdrawal technical capacity GWh/day	Injection technical capacity GWh/day	Access regime
United Kingdom	Hill Top Farm (Cheshire)	Salt cavern	EDF Energy	operational	0.57	136.80	0	No TPA
	Hole House Farm	Salt cavern	EDF Energy	operational	0.25	57.00	0	No TPA
	Cheshire (Holford GS)	Salt cavern	E.ON	operational	2.28	250.80	0	No TPA
	Hampshire	Depleted field	Humbly Grove Energy	operational	3.42	79.80	0	No TPA
	Hatfield Moor	Depleted field	Scottish Power	operational	0.80	20.52	20.52	No TPA
	Aldbrough I	Salt cavern	SSE/Statoil	operational	2.17	342.00	311.00	No TPA
	Hornsea (Atwick)	Salt cavern	SSE	operational	2.61	130.00	30.00	nTPA
	Stublach	Salt cavern	Storengy UK	operational	2.41	200.00	160.00	No TPA
	Holford	Salt cavern	Uniper Energy Storage	operational	1.95	238.33	238.33	

Source: Gas Storage Europe, 2018.

Annex 2. Inventory of LNG terminals of Europe

Table B.1. Inventory of EU LNG terminals: Large operational terminals.

Country	LNG Terminnal	Start-Up Date	Type	Operator	Vessel Size	Storage Capacity	Annual Send-Out Capacity	TPA Regime	Services
Belgium	Zeebrugge	1987	large onshore	Fluxys LNG	266,000 m^3	Current: 380,000 m^3, by 2019: 560,000 m^3	Current: 9 bcm/year, by 2019: 12 bcm/year	Regulated TPA	Regasification, reloading, trans-shipment, loading of bunkering ships, truck loading, small ship loading, cooling down and gassing up
France	Fos Tonkin	1972	large onshore	Elengy	From 7,500 m^3 to 75,000 m^3	155,000 m^3	3.4 bcm/year	Regulated TPA	Regasification, reloading, truck loading, small ship loading, and cooling and gassing up; rail loading is being considered
	Montoir	1980	large onshore	Elengy	From 65,000 m (Medmax) to 267,000 m^3 (Q-Max)	360,000 m^3, by 2023: 550,000 m^3	10 bcm/year	Regulated TPA	Regasification, reloading/ship loading, trans-shipment, loading of bunkering ships, truck loading, cooling and gassing up; rail loading is being considered
	Fos Cavaou	2010	large onshore	Elengy	From 15,000 m^3 to 267,000 m^3	Current: 330,000 m^3, by 2020: 550,000 m^3	Current: 8.25 bcm/year, by 2020: 16.5 bcm/year	Regulated TPA	Regasification, reloading, ship loading, small ship loading, trans-shipment, truck loading, cooling down and gassing up
	Dunkerque	2016	large onshore	Gaz-Opale (51% Dunkerque LNG, 49% Fluxys)	From 15,000 m^3 to 267,000 m^3	600,000 m^3	13 bcm/year	Exempted	Regasification, reloading, loading of bunkering ships and truck loading
Greece	Revithoussa	2000	large onshore	DESFA (Public Gas Corporation)	Current: 135,000 m^3, by 2018: 260,000 m^3	Current: 130,000 m^3, by 2018: 225,000 m^3	Current: 5.2 bcm/year, by 2018: 8.25 bcm/year	Regulated TPA	Regasification, truck loading storage as unbundled service, cooling down and gassing up; reloading and loading of bunkering ships are under study
Italy	Panigaglia	1971	FSRU	GNL Italia S.p.A.	Current: 70,000 m^3, by 2022: 140,000 m^3	Current: 100,000 m^3, by 2022: 240,000 m^3	current: 3.5 bcm/year, by 2022: 8 bcm/year	Regulated TPA	Regasification; reloading, bunkering and truck loading are under study
	Rovigo/Adriatic	2009	large onshore	Terminale GNL Adriatico Srl.	152,000 m^3	250,000 m^3	8 bcm/year	80% TPA exemption for 25 years	Regasification
	OLT Toscana	2013	large offshore (offshore Gravity Based Structure (GBS))	ECOS (Exmar, Fratelli Cosulich)		135,000 m^3	3.75 bcm/year	Regulated TPA	Regasification, storage bundle
Lithuania	Klaipėda	2014	FSRU	Höegh LNG/ Klaipėdos Nafta	160,000 m^3	170,000 m^3	4 bcm/year	Regulated TPA	Regasification, bunkering

Country	LNG Terminnal	Start-Up Date	Type	Operator	Vessel Size	Storage Capacity	Annual Send-Out Capacity	TPA Regime	Services
Malta	Delimara	2017	FSU + onshore regasification	ElectroGas Malta		125,000 m^3		Regulated TPA	Regasification, bunkering
Netherlands	Gate	2011	large onshore	Gate terminal B.V. (Vopak and Gasunie)	266,000 m^3	Current: 540,000 m^3, by 2018: 720,000 m^3	Current 12 bcm/year, by 2018: 16 bcm/year	TPA exemption for 16 bcm for 20 years	Regasification, ship loading, small ship loading, cooling down and gassing up
Poland	Świnoujście	2016	large onshore	Polskie LNG	216,000 m^3	Current: 320.000 m^3, by 2020: 480.000 m^3	Current: 5 bcm/year, by 2020: 7.5 bcm/year	Regulated TPA	Regasification, truck loading
Portugal	Sines	2003	large onshore	Ren Atlântico	7.6 bcm/year	390,000 m^3	40,000 m3 to 216,000 m3	Regulated TPA	Regasification, ship loading, truck loading, cooling down and gassing up
Spain	Barcelona	1969	large onshore	Enagas S.A.	266,000 m^3	840,000 m^3	17.1 bcm/year	Regulated TPA	Regasification, truck loading, cooling down and gassing up; loading of bunkering ships is being developed
	Cartagena	1989	large onshore	Enagas S.A.	266,000 m^3	619,500 m^3	11.8 bcm/year	Regulated TPA	Regasification, ship loading, truck loading, small ship loading, cooling down and gassing up, trans-shipment and loading of bunkering ships
	Huelva	1988	large onshore	Enagas S.A.	173,400 m^3	619,500 m^3	11.8 bcm/year	Regulated TPA	Regasification, ship loading, truck loading, small ship loading, trans-shipment, cooling down and gassing up; loading of bunkering ships is being considered
	Bilbao	2003	large onshore	Bahía de Bizkaia Gas (BBG)	270,000 m^3	450,000 m^3	8.8 bcm/year	Regulated TPA	Regasification, truck loading, cooling down and gassing up, loading of bunkering ships
	Mugardos	2007	large onshore	Regasificacion del Noroeste, S.A. (Reganosa)	266,000 m^3	Current: 300,000 m^3, by 2023: 500,000 m^3	Current: 3.6 bcm/year, by 2023: 7.2 bcm/year	Regulated TPA (open access)	Regasification, ship loading, truck loading, cooling down and gassing up, loading of bunkering ships; trans-shipment is under study
	El Musel	In hibernation	large onshore	Enagas S.A.	266,000 m^3	Current: 300,000 m^3, future: 600,000 m^3	Current: 7 bcm/year, by 2021; 8.8 bcm/year		Regasification, reloading, truck loading; trans-shipment and bunkering are under study
	Sagunto	2006	large onshore	SAGGAS	267,000 m^3	600,000 m^3	8.8 bcm/year	Regulated TPA	Regasification, truck loading, ship reloading, cooling down and gassing up; loading of bunkering ships is under study

Country	LNG Terminnal	Start-Up Date	Type	Operator	Vessel Size	Storage Capacity	Annual Send-Out Capacity	TPA Regime	Services
United Kingdom	Grain	2005	large onshore	National Grid	265,000 m^3	1,000,000 m^3	Current: 19.5 bcm/year, by 2020: 27.5 bcm/year	TPA exemption for 100% for 20 years	Regasification, ship reloading, trans-shipment, truck loading, rail loading, cooling down and gassing up; loading of bunkering ships will be available from 2019
	South Hook	2009	large onshore	South Hook Terminal Company Ltd	250,000 m^3	775,000 m^3	21 bcm/year	TPA exemption for 100% for 25 years	Regasification
	Dragon	2009	large onshore	Dragon LNG (Shell and Petronas)	217,000 m^3	320,000 m^3	7.6 bcm/year	TPA exemption for 100% for 25 years	Regasification

Source: (King & Spalding 2018), (Gas Infrastructure Europe 2019a) and (Gas Infrastructure Europe 2019b).

Table B.2. Inventory of EU LNG terminals: Small operational terminals.

Country	LNG Terminal	Start-Up Date	Type	Status	Operator	Vessel Size	Storage Capacity	Annual Send-Out Capacity billion m^3(N)/year
Finland	Tahkoluoto/Pori	2016	small onshore	existing	Gasum	20000	28500	0.1
	Tornio Manga	2018	small onshore	existing	Manga LNG		50000	0.4
Sweden	Lysekil	2014	small onshore	existing	Gasum		30000	0.3
	Nynäshamn	2011	small onshore	existing	AGA	15000	20000	0.3
United Kingdom	Gibraltar	2019	small onshore	existing	Gasnor (100% Shell)		5000	0.2

Source: (King & Spalding 2018), (Gas Infrastructure Europe 2019a) and (Gas Infrastructure Europe 2019b).

Table B.3. Inventory of EU LNG terminals: Under construction.

Country	Location	Start-Up Date	Type	Status	Operator	Vessel Size	Storage Capacity	Annual Send-Out Capacity billion m^3(N)/year
Belgium	Zeebrugge	2019	large onshore	expansion	Fluxys LNG	266000	566000	
Croatia	Krk Island, Omišal	2020	FSRU	new facility	LNG Croatia		140000	2.6
Finland	Hamina	2020	small	new facility	Hamina LNG Oy		30000	
Italy	Oristano - Santa Giusta	2020	small	new facility	Higas		9000	
	Ravena	2021	small	new facility	Depositi Otaliani GNL	27500	20000	
Poland	Swinoujscie	2021	large onshore	expansion	Polskie LNG	216000		7.5
	Swinoujscie	2023	large onshore	expansion	Polskie LNG	216000	480000	
Spain	Gran Canaria (Arinaga)	2027	large onshore	new facility	Gascan	140000	150000	1.3
	Tenerife (Arico-Granadilla)	2021	large onshore	new facility	Gascan	140000	150000	1.3

Source: (King & Spalding 2018), (Gas Infrastructure Europe 2019a) and (Gas Infrastructure Europe 2019b).

Table B.4. Inventory of EU LNG terminals: Planned.

Country	Location	Start-Up Date	Type	Status	Operator	Vessel Size	Storage Capacity	Annual Send-Out Capacity billion m^3(N)/year
Cyprus	Vassiliko	2020	FSRU	new facility	CYGAS		120000-250000	2.4
Estonia	Paldiski	?	large onshore	new facility	Balti Gaas	175000	160000	2.5
	TallinnLNG	?	mid - large onshore	new facility	Liwathon E.O.S.		4000 to 50000-250000	0.5
Finland	Rauma	?	small	new facility	AGA		10000	
France	Fos Cavaou	2022	large onshore	expansion	Fosmax LNG	267000		11
	Fos Cavaou	2024	large onshore	expansion	Fosmax LNG	267000	540000	5.5
	Montoir-de-Bretagne	2022	large onshore	expansion	Elengy	267000		7

Country	Location	Start-Up Date	Type	Status	Operator	Vessel Size	Storage Capacity	Annual Send-Out Capacity billion m^3(N)/year
	Montoir-de-Bretagne	2024	large onshore	expansion	Elengy	267000	10000	
Germany	Brunsbüttel	2022	large onshore	new facility	Gasunie, Vopak, Oiltanking	267000	240000	8
	LNG Stade GmBh	?	large onshore	new facility	Macquarie Group Ltd. - China Harbour Engineering Co			5
	Rostock transshipment	?	mid-scale	new facility	Novatek 49% - Fluxys 51%			
	Wilhelmshaven	2022	FSRU	new facility	UNIPER with MOL		263000	10
Greece	Alexandroupolis	2021	FSRU	new facility	Gastrade	170000	170000	6.1
Ireland	Cork	?	FSRU	new facility	NextDecade			4
	Shannon	?	large onshore	new facility	Shannon LNG	266000		6.2
Italy	Porto Empedocle (Sicilia)	2022	large onshore	new facility	Enel	155000	320000	8
Latvia	Kundzinsalas (Riga)	?	large onshore	new facility	Kundzinsalas			
	Skulte	?	FRU	new facility	Skulte LNG Terminal	170000		5
Netherlands	Gate terminal, Rotterdam	?	large onshore	expansion	Gate terminal	266000	720000	11
Poland	FSRU Polish Baltic Sea Coast	2025	FSRU	new facility	Polskie LNG/GAZ SYSTEM	170000	170000	4.1
Spain	Mugardos	2020	large onshore	expansion	Reganosa	266000		
	Mugardos	2022	large onshore	expansion	Reganosa	266000	320000	
	Mugardos	2023	large onshore	expansion	Reganosa	266000		3.1
Sweden	Gävle	?	small	new facility	Gasum		30000	0.3
	Göteborg	?	small	new facility	Swedegas	75000	25000	0.5
United Kingdom	Isle of Grain	?	large onshore	expansion	Grain LNG	266000	1175000	26.5
	Port Meridian	?	FSRU	new facility	Port Meridian Energy		170000	5

Source: (King & Spalding 2018), (Gas Infrastructure Europe 2019a) and (Gas Infrastructure Europe 2019b).

Table B.5. Inventory of EU LNG terminals: Suspended.

Country	Location	Start-Up Date	Type	Status	Operator	Vessel Size	Storage Capacity	Annual Send-Out Capacity billion m^3(N)/year
United Kingdom	Trafigura Teeside	2007	gas port	existing	(Trafigura)	150000	0	4.2

Source: (King & Spalding 2018), (Gas Infrastructure Europe 2019a) and (Gas Infrastructure Europe 2019b).

Annex 3. Tests of hypothesis for the incident frequencies of LNG facilities in the GIIGNL database

In this annex we develop the hypothesis tests performed to identify what periods in the GIINL database have statistically significant different frequencies of incidents and what periods do not show such significant differences. We consider that the number of incidents, X, that take place over a given observation period, t_1, follows a Poisson distribution with parameter λ_1 (expected number of incidents per unit of time), and expected value $\lambda_1 \cdot t_1$. This variable, when the observation period is large enough will converge to a normal distribution with expected value $\lambda_1 \cdot t_1$ and variance $\lambda_1 \cdot t_1$ (the approximation is considered good enough for $\lambda \cdot t > 5$). Thus we can write

$$X \sim N(\lambda_1 t_1, \lambda_1 t_1) \quad [1]$$

For another observation period of length t_2 and expected number of incidents per unit of time λ_2, the random variable number of incidents in the period (Y), will follow the corresponding normal distribution

$$Y \sim N(\lambda_2 t_2, \lambda_2 t_2) \quad [2]$$

Thus, the difference between both variables will also follow approximately the normal distribution

$$X - Y \sim N(\lambda_1 t_1 - \lambda_2 t_2, \lambda_1 t_1 + \lambda_2 t_2) \quad [3]$$

In section 4.4.5 we report the results of five samples taken over five non-overlapping periods. And we want to know if those results are likely to come from different Poisson distributions or from the same. In order to answer this question we will build a statistic that will help us identifying if the sample differences as small as to consider that they proceed from the same Poisson distribution, or if the differences do not allow us to keep such hypothesis and we have to consider that they come from different Poisson distributions. Plainly speaking, we want to know if the number of events observed in two different periods (observed values of X and Y) are likely to come from the same Poisson distribution with parameter λ, or if they are different (two Poisson distributions with expected number of incidents per unit of time λ_1 and λ_2 respectively). To build such a statistic we take into account that from equation [3] we can conclude that

$$\frac{(X-Y)-(\lambda_1 t_1 - \lambda_2 t_2)}{\sqrt{\lambda_1 t_1 + \lambda_2 t_2}} \sim Z \quad [4]$$

Where Z stands for the standard normal distribution. We want to test the null Hypothesis

H_0: $\lambda = \lambda_1 = \lambda_2$

Versus the alternative

H_0: $\lambda_1 \neq \lambda_2$

In the conditions of the null hypothesis equation [4] becomes

$$\frac{(X-Y)-\lambda(t_1 - t_2)}{\sqrt{\lambda(t_1 + t_2)}} \sim Z \quad [5]$$

Which will be the measure of discrepancy that we will use to test the null hypothesis. In order to effectively perform the tests, we will replace X and Y by their observed values in the samples, x and y, and we will replace λ by its best estimate which is

$$\hat{\lambda} = \frac{x+y}{t_1+t_2} \quad [6]$$

After some algebra, the statistic is calculated as

$$\sqrt{x+y}\left[\frac{x-y}{x+y} - \frac{t_1-t_2}{t_1+t_2}\right] \quad [7]$$

and it is compared with the quantiles of the reference standard normal distribution as in a usual bilateral test Results of all tests of hypothesis performed are shown in table C.1. P_values smaller than 0.05 take us to reject the null hypothesis and consider that there are significant differences between the frequencies of incidents in each pair of considered periods. These cases have been highlighted in red ink.

Table C.1. Summary of hypothesis tests performed.

Periods 1/2	Sample size period 1 (t_1) [site-yr]	Sample size period 2 (t_2) [site-yr]	Number of incidents in period 1 (x)	Number of incidents in period 2 (y)	Statistic (absolute value)	P-value
1965-1974 1975-1984	44	179	15	52	0.435	0.66
1975-1984 1985-1994	179	327	52	94	0.06	0.96
1965-1974 1985-1994	44	327	15	94	0.40	0.68
1965-1994 1995-2000	550	191	161	85	2.75	0.006
1965-1994 2001-2007	550	579	161	82	5.47	$< 10^{-4}$
1995-2000 2001-2007	191	579	85	82	6.74	$< 10^{-4}$

Annex 4. Tests of hypothesis for the frequencies of incidents in the 10th EGIG report

This section contains the tests of hypothesis to check what periods in the 10th EGIG report may be considered to have the same frequencies of incidents and what periods have definitely different frequencies of incidents. The tests performed follow the same rationale as the ones performed in Annex 3. The results are contained in Table D.1. P-values smaller than 0.05 take us to reject the null hypothesis and consider that there are significant differences between the frequencies of incidents in each pair of considered periods. These cases have been highlighted in red ink.

Table D.1. Summary of hypothesis tests performed.

Periods ½	Sample size period 1 (t_1) [thousands of km·yr]	Sample size period 2 (t_2) [thousands of km·yr]	Number of incidents in period 1 (x)	Number of incidents in period 2 (y)	Statistic (absolute value)	P-value
1970-1976 1977-1986	290	680	223	420	2.42	0.016
1977-1986 1987-1996	680	910	420	305	8.17	$< 10^{-4}$
1987-1996 1997-2006	910	1,140	305	210	6.73	$< 10^{-4}$
1997-2006 2007-2011	1,140	674	210	111	0.92	0.36
2007-2011 2012-2016	674	716	111	97	1.41	0.16
1997-2006 2011-2016	1140	716	210	97	2.45	0.014

KJ-NA-30470-EN-N

The European Commission's science and knowledge service

Joint Research Centre

JRC Mission

As the science and knowledge service of the European Commission, the Joint Research Centre's mission is to support EU policies with independent evidence throughout the whole policy cycle.

EU Science Hub
ec.europa.eu/jrc

@EU_ScienceHub

EU Science Hub - Joint Research Centre

EU Science, Research and Innovation

EU Science Hub

Publications Office
of the European Union

doi:10.2760/338818

ISBN 978-92-76-25201-6