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Flexible LNG Facilities

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Executive Summary

The LNG industry has passed its 50th year and now many facilities have aged. Meanwhile, the nature of LNG market has changed significantly. These changes have led to the need for terminals to modernize and become more flexible by adding new functionality beyond their traditional role.

Flexible LNG facilities are those facilities to which functions and activities are added or changed to allow for different uses or operations. In many cases, the original design purpose for these LNG facilities is retained but, in other cases, changes may alter the design function.

Traditionally, the LNG value chain has been rigid, with building blocks which are well-defined with limited functionalities:

- **LNG Export Facilities** – Where Natural Gas is treated, cooled and liquefied to be shipped to LNG Markets
- **Floating Facilities**– LNG carriers which transport LNG to suppliers on long-term contracts.
- **LNG Import Terminals** – Where LNG is received, stored and regasified to be provided to customers
- **Peak Shaving Facilities** – Where natural gas is cooled, liquefied and stored, ready to be regasified to meet periods of peak demand

Changes are now being seen in the value chain and in each of these building blocks with the addition of new functionalities as outlined in Figure 1. In the first link of the LNG chain, **LNG Export Facilities** are not only adapting to changing feed gas compositions due to aging or new gas fields but, in many cases, they are also adding additional facilities to extract and sell new products such as ethane, LPGs, and Helium.

The role of **Floating Facilities** is also changing with the evolution of the industry. Whilst the floating element in the value chain is traditionally the LNG carrier servicing long-term supply contracts, enhanced functionality can be found in the conversion of LNG carriers to floating

facilities such as Floating Storage and Regasification Units (FSRU), Floating Storage Units (FSU) and Liquefaction (FLNG). The potential for floating facilities to be redeployed elsewhere brings additional unique flexibility to this element of the LNG value chain, whether they constitute a conversion or new build.

Flexibility is also being introduced in **LNG Import Terminals**, which have the potential to serve as an LNG Hub, where LNG is received in bulk volumes from an LNG carrier and is then distributed by many different channels, parallel to the typical send-out gas pipeline. This can occur, for example, in smaller quantities as a liquid distributed in LNG trucks or small-scale LNG carriers to enter the LNG-for-Transport market. The addition of other services such as transshipment, the reloading of small scale LNG carriers to feed other LNG terminals, and LNG Carrier gassing-up and cooling-down can also increase the terminal operator's commercial palette, as shown in Figure 1.

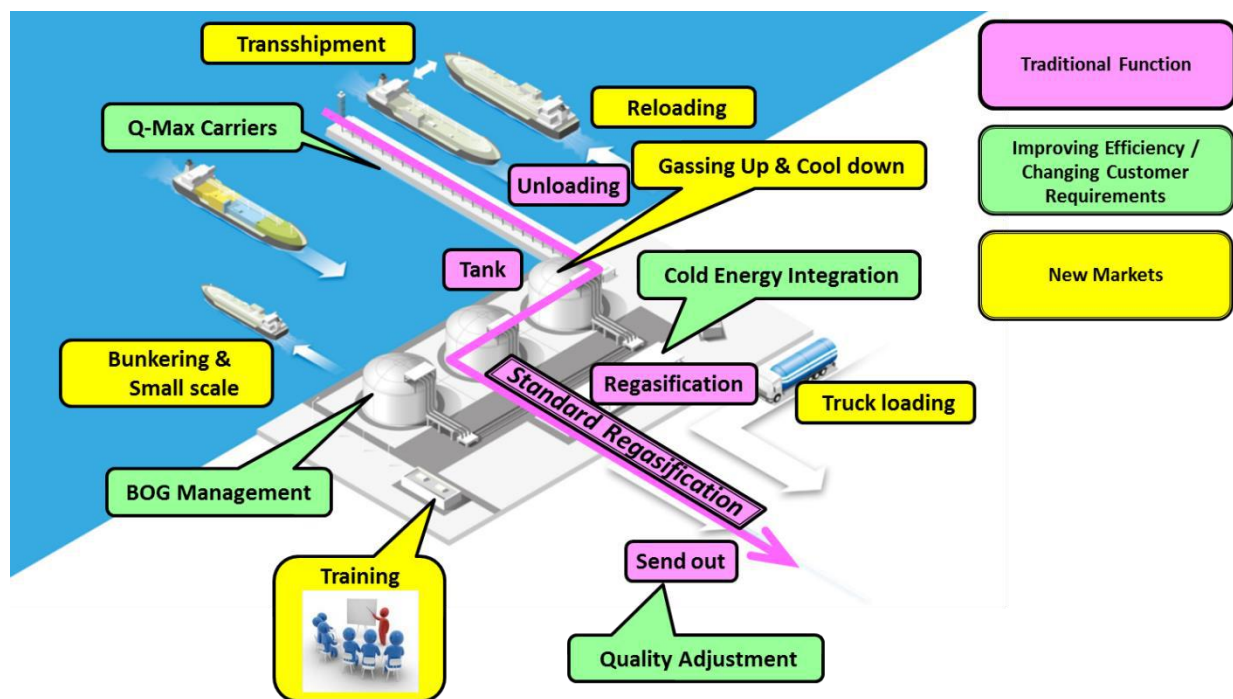


Figure 1: Flexibility in LNG Import Terminals

Peak shaving Facilities have also been subject to profound changes in the LNG value chain, particularly in North America. The most common addition to peak shaving facilities is truck-loading facilities to allow terminals to access the high-value LNG for transport market.



Finally, the most substantial and visible change in functionality is the inversion of functionality in a facility. This can be seen in the well documented Import-to-Export LNG terminal conversions in the U.S. but also, in contrast, where a liquefaction plant has been converted to an Import Terminal to meet rising local demand, such as the PT Arun LNG Terminal in Indonesia.

The addition of these new functionalities can be attributed to a range of drivers which can be broadly classified as either business-driven, where change is initiated by the terminal in a bid to enter a new market segment or adapt to market changes, or stakeholder-driven, where the terminal needs to adapt to the changing demands of suppliers, regulatory bodies and society.

In order to meet the Paris Agreement on Climate Change targets, the global energy mix will see significant decarbonization. As part of this transition, the role of LNG is forecast to grow not only in providing gas-to-power but also in new markets such as fuel for the haulage and maritime sectors. This will lead to the growth of LNG Hubs where the core business is LNG breakbulk with redistribution to smaller satellite terminals, re-export of LNG, and the provision of LNG for transport sector.

In addition, as society moves towards a carbon-neutral energy mix, new functionalities could be envisaged. One such new functionality is associated with the increase in bio-gas production. This presents an opportunity for facilities in biogas-producing countries to become involved in the development of the bio-LNG market. This may involve the addition of bio-LNG treatment and small-scale liquefaction units. For instance, in France, which has set the target that 10% of all gas will come from renewable sources by 2030, facilities will be needed to store and transport this gas.

In the more than 50 years of the LNG business, there have been many changes and evolutions. As industry continues to grow and develop, changing market demands coupled with the acceleration of the energy transition will lead to significant opportunities for those terminals



able to adapt to the new reality. Embracing the functionalities outlined in this report will be key for all elements of the LNG value chain if they are to secure their part in the growing role of LNG in the future energy landscape.

1 Introduction

With an increase in demand for clean sources of energy and despite continued volatility in world energy market prices, the LNG sector of the international gas industry has seen consistent worldwide growth, with LNG demand increasing from around 50 million tonnes (MT) in 1990 to 293 MT in 2017.¹ Coupled with this rise in LNG volumes traded, the industry's value chain is also undergoing a transformation from its traditional structure of liquefaction, shipping and regasification with new functionalities and activities being added beyond the traditional functions of these elements.

Over the past 50 years, the traditional LNG value chain has had a well-defined structure, starting with the liquefaction of natural gas at export terminals, enabling countries with plentiful natural gas reserves to monetize their stranded gases as LNG to reach major markets. In this structure, the LNG has then been shipped to receiving markets. The trading of LNG has been based on long term supply contracts to import terminals where the LNG was unloaded and regasified for industrial, commercial, and residential purposes. Complementary to these activities, LNG peak-saving facilities have been used to store natural gas to manage peaks in gas demand.

This report addresses new functionality in the full range of LNG value chain themes, the archetypal functionalities associated with these themes are outlined in **Chapter 2**.

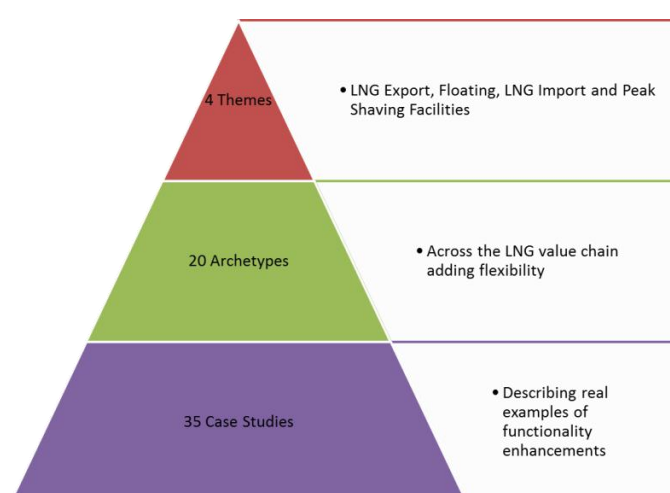


Figure 2: Structure of the Study Process from Case Studies which can be attributed to archetype functionalities which are found in the four identified themes

¹ IGU World LNG Report 2018



Economic opportunities and needs which represent drivers for changes in functionality are discussed in detail in **Chapter 3**. Changes to the value chain have many drivers, varying from access to LNG markets; increasing volumes of LNG spot trading; changes in gas or LNG supply; and financial pressures leading to the need for lower capital expenditure (CAPEX) investment, shorter time schedules, and increased infrastructure efficiency.

Notably, these changes have required, and will continue to require, alterations in the worldwide LNG value chain and its operation. These include implementing physical changes to the industry's infrastructure and adapting new business models. Such changes can take several forms. For example, accessing new LNG market segments requires the addition of truck loading, bunkering, or reloading facilities.

Opportunities and challenges in implementing these changes are outlined in **Chapter 4**. Beyond the functional changes seen to date, this chapter also provides consideration of more general opportunities for the global LNG industry and the potential for application of functionalities to provide pathways into the future of the industry. These opportunities can give industry decision-makers options for creating resiliency in the core business that LNG facilities and operations support.

Understanding the challenges faced when making functional changes in facilities and operations may be the first step in avoiding inefficiencies and value erosion when developing new functionalities in LNG assets. Therefore, the report also provides initial characterizations of these challenges.

Case studies of facility functionality changes are provided in **Chapter 5** for all the value chain elements addressed. As in many studies, documentation of actual experience in the form of case studies provides the richness in detail of individual projects involved in functionality changes and clearer evidence of the practical impacts of drivers and other factors behind these changes. The case studies address actual changes in physical infrastructure, facility operations, exploitation of new economic opportunities and business-related factors associated with functional changes.



Through this report, the Study Group hopes that readers will begin to appreciate how the worldwide LNG industry has adapted its physical facilities and investment in infrastructure to changing energy market requirements. The report will explore how the industry has developed its own ideas on how assets might be altered in the future to address new challenges. These include an increased need to address market flexibility as well as other global priorities such as reducing atmospheric carbon emissions from the energy industry. The LNG industry provides many examples of how changing requirements can drive change and adaptation in natural gas facilities.

Finally, in **Chapter 6** the outlook for increasing LNG facility functionality is discussed. Here, the report considers proven and potentially new approaches to employing functional changes in existing LNG facilities. It is hoped that readers will see this discussion as a starting point and that, with the evolution of the industry, many new functionalities for the industry may be envisaged.

The objective of the report is to give readers an understanding of the breadth of changes in functionality that have been implemented and might be extended to other changes in LNG infrastructure. While some readers may be very familiar with specific project examples of such changes, the report intends to provide a systematic summary and analysis of the LNG industry as a whole. Readers should be aware that the examples and cases described in the report are based on experience compiled at the time the report was written and, therefore, may not account for the most recent alterations in facility functionality.

2 Flexibility: Definition and Types

'Flexibility' is defined as 'the quality of being able to change or be changed easily according to the situation'.² For this report, flexible LNG facilities are those facilities to which additional functions and activities are added to allow for changes in use or operation. These changes are designed to serve new objectives, customers or markets, based on new business drivers, opportunities, or needs, or a combination of these factors. They can be put into operation relatively easily once essential infrastructure changes are implemented. In many cases, the original design purposes for these LNG facilities are retained, but in other cases, changes may alter design functions.

For each of the four themes some typical archetype groups have been identified. These are outlined in the diagram below.

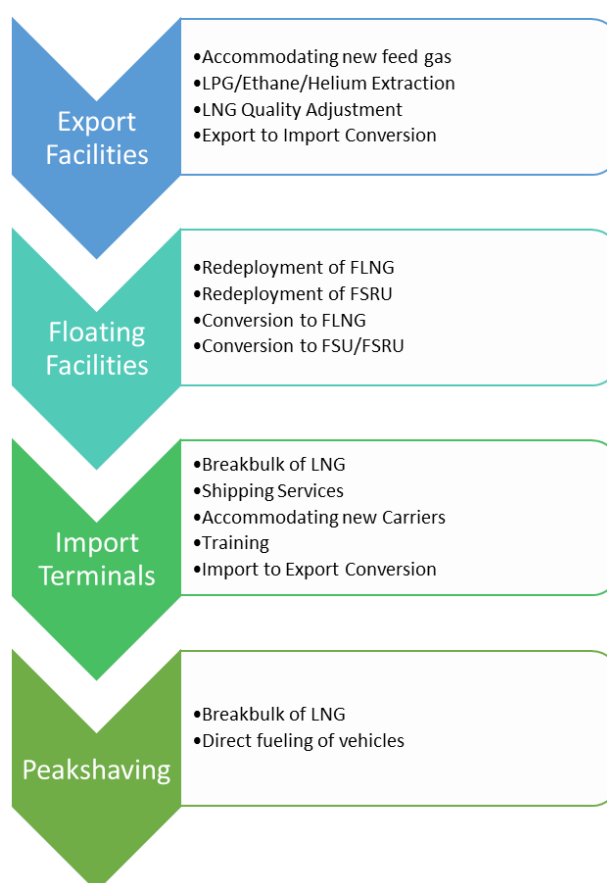


Figure 3: Overview of Themes and Archetype Groups

² Cambridge Dictionary, Cambridge University Press, 2017.
<http://dictionary.cambridge.org/dictionary/english/flexibility>.

2.1 Flexibility in Export Facilities

The main purpose of an LNG Export Terminal is to produce LNG at atmospheric pressure. This process involves a phase change in the natural gas from vapour to liquid. The phase transition increases the energy density of the natural gas by a factor of around 600, compared to natural gas at atmospheric temperature and pressure. Liquefaction is achieved by cooling the natural gas against one or more refrigerant cycles.

Prior to the liquefaction process, the natural gas supplied to the plant needs to be treated. The treatment will vary depending on feed gas source but typically includes removing contaminants such as acid gases, water and mercury, as well as potentially extracting heavier hydrocarbons which may be sold at a higher margin.

The process described above can be considered typical for a traditional LNG terminal. However, in recent years several archetypes have allowed terminals to demonstrate flexibility in the face of changing and often challenging conditions.

2.1.1 Accommodation of new feed gases

One such archetype is the accommodation of new feed gases. This requires detailed study and often entails plant modifications. Over the lifetime of a liquefaction terminal, the supply to the plant is likely to change for many reasons including: depletion of the original gas field leading to changing composition, new fields being supplied to the facility in so-called 'back-fill' projects, and changes in the treatment of natural gas upstream. These changes in feed gas composition may challenge the ability of the original design of the LNG plant to continue to meet the same product specifications and production rates.

Therefore, there has been a substantial rise in the number of Brownfield Projects (i.e. projects at existing LNG plant sites) making modifications to help plants handle the new or changing feed gas compositions to continue to meet customer specifications. These modifications might include changes or additions to the Acid Gas, non-gaseous liquid (NGL) Removal Units, or dehydration facilities.

2.1.2 Product Extraction

New or additional product extraction facilities have been increasingly added to LNG Terminals when a new market opportunity arises for one or more of the feed gas components. These new market opportunities can often provide lucrative outlets for products which are less valuable as components of the LNG product. The most common examples of products extracted are Helium and hydrocarbons such as LPGs, NGLs or ethane.

Demand for Helium has grown rapidly over the past decade and this has led to Helium extraction facilities becoming an economically attractive addition to LNG terminals. The Helium extracted from gas can be sold to the automotive, medical and nuclear industries, amongst others. Similarly, hydrocarbon extraction can prove lucrative. Hydrocarbons are often extracted when a market opportunity for sales opens or when the content of liquid hydrocarbons in the feed gas increases.

2.1.3 LNG quality adjustment

One of the impacts of changing feed gas or adding new product lines is that the quality of the LNG produced may change. One of the consequences of this is that LNG may no longer meet the specifications of the Sales and Purchase Agreements (SPAs) with the customers. Many facilities have decided to deal with this by adding LNG quality adjustment facilities to allow for blending. Alternatively, if LNG of different qualities can be produced where different LNG train designs operate in parallel, the operator may decide to have two different LNG products. For example, lean LNG and rich LNG as produced by Qatargas.

2.1.4 Export-to-Import Conversion

Export-to-Import Conversion is an example of extreme flexibility where, due to decreasing feed gas availability and increasing domestic demand, the LNG Value Chain is completely reversed. Whilst only one example of such a conversion has occurred to date, it is likely that more may occur as energy demand increases in newly industrialized and developing countries. This can prove an attractive option, as the most significant CAPEX and schedule items - such as LNG storage tanks and jetties - can be readily utilized in an Import Terminal with relatively minor modifications. This improves CAPEX and Schedule compared to a newly built LNG Import Terminal.

With the increase in volumes of LNG being traded many exporters have started to ship LNG in larger quantities. The first LNG carriers from the Arzew terminal had a capacity of around 25,000 m³ whereas today the largest Qmax carriers of Qatargas have a capacity over 10 times greater. To be able to accommodate larger carriers, the export facilities have had to make modifications to the jetty facilities. As LNG Import Terminals generally have more variation in the LNG carriers they receive, this archetype is described in more detail in section 2.3.



Figure 4: The Mozah Qmax LNG carrier at Ras Laffan. The Qmax fleet are the largest LNG carrier ever built, often modifications are required before a terminal can receive a vessel this large. Photo from [wikimedia.org](https://www.wikimedia.org)

2.2 Flexibility in LNG Floating Facilities and Shipping

Changes in the global LNG market have implications for LNG logistics and transportation. Traditionally, LNG carriers, both chartered and owner-operated, have been employed in the transportation of long-term contracted LNG between Export Terminals and Import Terminals. However, in recent years the increase in the volume of LNG traded coupled with the rise of the LNG spot market have required LNG logistics to become more flexible.

In addition to the changes to logistics, the industry has experienced an increase in the number of floating LNG facilities in recent years. Some of these facilities are new and purpose-built, but others are existing LNG carriers which have been converted into FSUs, FSRUs or FLNG.



Figure 5: The FSRU Toscana located offshore Italy is a conversion of the LNG Carrier Golar Frost.
Photo from <https://commons.wikimedia.org>

2.2.1 Conversions

The introduction of new larger and more efficient LNG carriers (LNGCs) has led to a surplus of older vessels. To create value from the older vessels, companies have been exploring opportunities to convert carriers into floating regasification terminals. To date, five conversion projects have been completed.

LNGCs can be used to simply store LNG (FSU) with traditional regasification facilities onshore. Alternatively, the liquefaction or regasification modules can be installed on the carrier itself (FSRU).

Similar to conversion into FSU/FSRU, it is also possible to convert an LNG Carrier to allow it to liquefy and store LNG. The conversion of LNGCs to FLNG facilities enables a faster schedule to deployment with lower CAPEX than a new-build FLNG or onshore terminal. Converted FLNG facilities have limited production volumes due to their size. However, they will enable the monetization of smaller stranded gas fields. To date there has been only one example of such a conversion, the Golar Hilli Episeyo to be deployed offshore in Cameroon. This project uses a converted Moss carrier built in 1975 that has been retro-fitted with Black & Veatch's PRICO single mixed refrigerant process.

2.2.2 Redeployment

An advantage of a floating facility, new build or converted, over a traditional onshore terminal is its ability to be deployed. This allows operators to charter a vessel to meet a relatively short-term demand. This could include enabling early deployment of natural gas into a market whilst plans for a larger onshore terminal are developed. Additionally, FSRUs also offer flexibility to operators if natural gas demand does not grow as expected. In this case, the vessel can be redeployed to a new market with relative ease.

Floating liquefaction facilities are generally considered to be flexible by nature; they can be reused and moved from location to location as the economics or resources change. To make use of this option, the FLNG design needs to be flexible enough to handle a wide range of feed gas qualities, operating conditions (weather) and metocean conditions (forces introduced by wave motion). This can be challenging in view of the costs, and weight and space constraints faced during detailed design.

One example of FLNG flexibility is the Caribbean FLNG project. This project envisaged the deployment of an FLNG facility to process and liquefy gas off the coast of Colombia. However, this project was cancelled in March 2016, after the construction of the FLNG facility was complete, because feed gas was no longer available at the original location. The Caribbean unit is now waiting to be re-located and a number of potential FLNG projects are being assessed.

2.3 Flexibility in Import Terminals

New flexibility at LNG Import Terminals is a key part of the overall changes occurring across the LNG value chain. The addition of new functionalities can be driven by changing business models and market conditions, as well as new business opportunities. Several archetypes have been developed to offer a variety of new services in addition to standard regasification.

These new services are based mainly on advantages intrinsically linked to LNG terminals, which can be grouped into three categories:

2.3.1 Breakbulk of LNG

Traditionally, LNG Import Terminals have operated on a “Liquid In-Gas Out” premise, whereby LNG is unloaded, stored and regasified. However, in recent years, an increasing number of terminals have included extra functionalities, which offer LNG as product to new markets and customers. This gives terminals the flexibility to function also on a “Liquid In-Liquid Out” basis. The process of taking a shipment of LNG and then reselling the LNG in smaller products is often referred to as “Break Bulking” with the bulk of LNG being broken down into smaller packages.

There is a growing market for LNG as fuel, both in shipping and for heavy road transport. New markets serve as potential outlets for Import Terminals to sell LNG to a premium market. Bunkering is the supply of LNG to a vessel for use as fuel. The LNG can be provided to the customer either by truck or by dedicated bunker vessels. The most common bunkering method uses an LNG truck to refuel a vessel moored at a berth. LNG is then transferred using a flexible hose. However, LNG trucks are relatively small (<80 m³) and therefore can only be used to supply small-scale LNG fuelled vessels. In order to supply LNG to large vessels, dedicated bunker barges have been developed with a higher storage capacity and faster loading rates.

Peak Shaving Facilities

This report also extends the definition of ‘break bulk’ operations to peak shaving facilities, which use storage capacity to support some of the types of operations discussed above. This

includes use of peak shaving storage capacity to support marine bunkering operations and truck loading for merchant gas and other off-site operations. Readers will be most familiar with use of the term ‘break bulk’ in marine transfer operations. However, as discussed in Chapter 2 on “Flexibility: Definition and Types” and shown in Figure 2, this concept can be extended to non-marine applications.



Figure 6: SABIC's (Saudi Basic Industries Corporation) chartered vessel, the Coral Sticho, awaiting LNG bunkering at Teesport, U.K. Photo courtesy of Shell

In addition to providing bunker fuel, truck loading can also supply retail stations with LNG. The LNG is supplied via tanker truck to the retail station where it is unloaded and stored in a small storage tank, before being supplied to haulage vehicles. In addition to providing access to premium fuel markets, truck-loading facilities can also allow natural gas to be provided to customers who are not connected to a central distribution grid. The LNG can then be regasified and supplied to residential or commercial customers

2.3.2 Shipping Services

One common method of breakbulking is to reload the LNG onto an LNG Carrier. This may be a conventional carrier but may also be a small-scale LNG carrier. The reloading process allows the LNG to then be sold to markets where there is a higher demand for LNG, or to smaller markets which cannot be served by larger LNG carriers. In addition to reloading, terminals

may also consider the transshipment of LNG between two carriers. This takes place either at an LNG terminal or in sheltered waters.

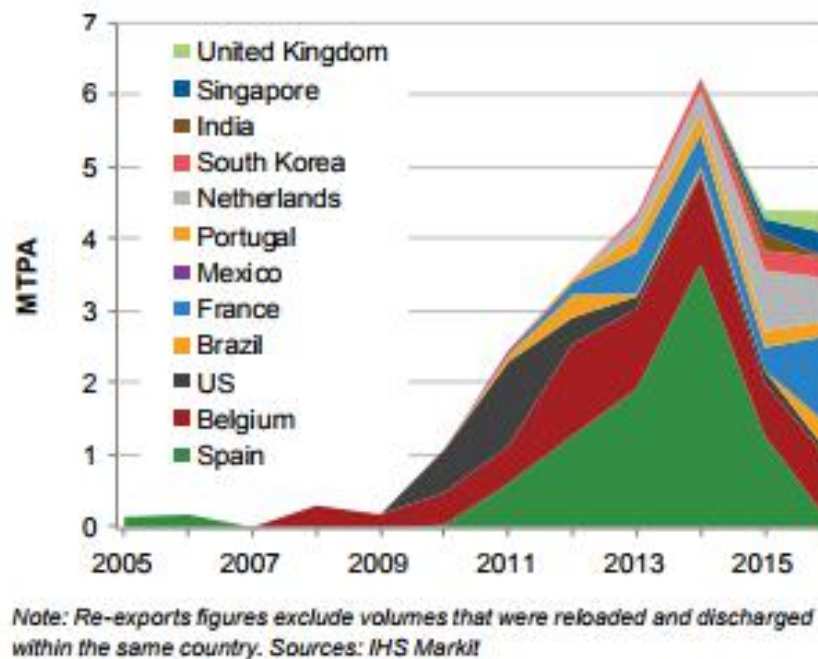


Figure 7: Overview of growth in LNG volumes reloaded

Once a terminal has the facilities to load LNG onto a carrier, that terminal can also provide Gassing-Up and Cooldown Services. These could be offered to a vessel after dry docking or to new build vessels. Gassing-up is the replacement of inert gas in the cargo tanks by warm LNG vapor at the receiving terminal, and cooldown is an operation to pre-cool cargo tanks after gassing up. It is preferable to offer cooldown services at an LNG Import Terminal where berth time is in lower demand than at traditional LNG Export Terminals.



Figure 8: Truck loading stations in Cartagena Plant. Photo courtesy of Enagas

2.3.3 Improved Efficiency

In recent years, many terminals have taken steps to improve their efficiency. These changes are often driven by tightening environmental regulations, for example stricter rules on flaring, venting and CO₂ emissions. However, improvements can often be justified on economic grounds too, with increased product available for sale or reduced operating costs.

For example, when a terminal is designed, one of the most important criteria is the minimum natural gas sendout. This is the minimum amount of gas which the terminal can emit without the need for flaring. In the last few years, especially in certain areas including Europe, the sendout of these terminals has decreased to below design conditions. To avoid flaring gas, terminals have been forced to make changes to their BOG management systems. Such changes typically consist of either the addition of new facilities, such as a recondenser pre-cooler or on-line BOG compressor, or the optimization of existing facilities to avoid flaring at very low sendout during LNG carrier unloading or reloading.

When terminals are located near industrial customers, there is often the opportunity to look for synergies between the terminal and its neighbours. As the regasification of LNG requires the release of a substantial amount of 'cold energy' that in many cases is not utilized, this energy can be provided to neighbouring facilities who require a cold source. Typically, LNG regasification is performed using an open sea water circuit to vaporise the liquid. Therefore,



the cold energy is sent back to the sea and lost. However, an intermediate heat transfer fluid can be used to recover the cold energy, which will be used in another process. Opportunities for the utilization of this cold energy include heat exchanges with refineries and power plants, providing a cold source for cryogenic air separation and carbon dioxide liquefaction facilities as well as more niche opportunities such as refrigeration for cold storage warehouses.

2.3.4 External Market Influences

The modern LNG market has also driven changes in many LNG terminals. Traditionally, LNG has been delivered to terminals through long-term fixed contracts using dedicated shipping fleets. However, recent developments have seen an increase in spot market trading which often leads to terminals receiving different LNG carriers. Moreover, the size of LNG carriers has increased, with many terminals being unable to receive the most modern Qmax and Qflex carriers due to limitations of the jetty and receiving facilities. To overcome these limitations, these facilities would need to be extended. Typical adjustments to the existing jetty might include extending the marine loading arms' envelope, increasing the size of fenders, providing additional mooring hooks, and making changes to the ship access tower. Alternatively, adding a second jetty, which may also allow for transshipment, may be an option. This will also allow the terminal to increase the number of unloading/reloading operations and therefore increase terminal availability.

Another impact of increasing LNG carrier size is that the LNG Import Terminal may not have sufficient storage capacity to receive the larger volumes of LNG supplied by modern carriers. Therefore, terminals may consider adding additional LNG storage. Where plot space allows, this may mean building new tanks in addition to existing storage or, when sites are constrained by land availability, demolishing older tanks and replacing them with larger tanks with a similar plot area.



Figure 9: The *Sevilla Knutsen* at the Cartena Terminal. Photo courtesy of Enagas

Another effect of the increase in the number of spot cargos traded is that terminals will often receive LNG which is of different quality to that seen in the past. As the LNG importer has an obligation to provide consumers with a supply of natural gas at a required level of calorific value, LNG blending facilities at the Terminal may be needed in order to modify the LNG quality. Quality adjustment facilities allow the higher heating value (HHV) of the sendout gas to be lowered or increased through addition of N₂ or propane. LNG from different cargos can also be mixed to change the quality of the send-out natural gas and thus to widen the range of LNG acceptable to terminals.

As terminals have developed deep technical knowledge over the past 50 years, many have established training centres to train the next generation of operators and engineers. This has also created an opportunity to add a new business stream for the terminal operator by offering these training courses and facilities to third parties.

All these new services make today's LNG terminals a real LNG hub, where LNG is unloaded, stored, reloaded, redistributed and reused. Thanks to the expertise acquired by LNG terminal operators around the world over more than 65 years of experience, import terminals have been able to transform and adapt to the new realities of the global LNG market.

2.4 Flexibility in Peak Shaving Facilities

The development of LNG peak shaving infrastructure worldwide is limited to gas markets requiring periodic peaks in supply. These peaks are chiefly related to weather-sensitive demand for natural gas and pipeline constraints in meeting that demand.

Generally, peak shaving plants were built to serve end-use markets connected to a highly-integrated transmission pipeline system with physical constraints impeding the delivery of natural gas during peak demand periods. These periods were, and still are, most pronounced during periods of cold weather when natural gas use for heating by end customers drives marginal increases in demand.

The construction of peak shaving plants in North America, most active in the 1970s and 1980s, was particularly significant in pipeline-constrained regions. It often occurred at “end of the pipeline” locations, where network flows of natural gas were unavailable to replace or supplement deficiencies from the single supply source or serving pipeline.

In their design, North American peak shaving plants were generally optimized to the “200/20” rule of thumb, where approximately 200 days of liquefaction was installed to store LNG over the course of the calendar year. This was designed to meet peak demands lasting up to approximately 20 days of regasification send out to the local distribution network.

A chief opportunity for expanding LNG peak shaving functionality comes from the availability of excess LNG storage capacity in areas where such additional capacity is difficult to site. Excess storage capacity may arise from increased capacity in the pipeline to the local distribution area, decreased local peak gas demand, and/or observed declines in weather-sensitive demand. Increased pipeline capacity development has been stimulated by a rise in aggregate demand for natural gas and the need to integrate new natural gas supplies into the network. Demand on existing networked natural gas systems, such as those in North America, have increased the number of end uses, particularly the displacement of other fuels (most notably fuel oil for heating) and the increased use in power generation.



The development of shale gas in the U.S. has brought additional supplies into the integrated market and created new supply regions. In many cases, this creates a need to build new pipelines, expand the capacities of existing systems, and even reverse flows in existing pipelines to match the supplies to existing markets.

Declines in local peak demand have resulted from milder winter temperatures for most of the last decade, increased and optimized pipeline operations, the development of other storage sources, and changes in end-use markets and peak service requirements. Extremes in North American winter temperatures have lessened, with generally warmer winter weather, decreasing the need for peaking services and pipeline deliverability constraints. Expanded pipeline segments, renovated compression facilities, and improved dispatching has helped to optimize pipeline operations, improving delivery during peak periods. The increased capacity of underground storage in mid-stream regions and near local distribution systems has alleviated deliverability constraints in many local markets, including during peak services. Most peak shaving capacity is located within developed areas where greenfield LNG storage capacity is hard to site due to regulatory restrictions and public opposition.

In North America generally, and in the U.S. in particular, site requirements implemented by federal and state/provincial governments form barriers to siting new LNG facilities, especially LNG storage. Under the U.S. regulatory regime, LNG storage facilities built before new legal and regulatory requirements came into effect in the late 1970s and were “grandfathered” from many of the new storage requirements, which, in densely occupied areas, effectively banned the siting of new facilities.

In Canada, peak shaving facility expansion and the transition to merchant operations and marine bunkering are led by Gaz Métro’s various expansion projects in Quebec on the St. Lawrence River valley, and Fortis LNG’s Tilbury project in British Columbia on the Canadian west coast. Gaz Métro has worked closely with provincial development authorities during the company’s expansion into satellite operations, trucking LNG under merchant arrangements to other natural gas distributors in Canada and the U.S., marine bunkering in St. Lawrence.



Likewise, Fortis LNG has developed progressive relations with stakeholders in the west, emphasizing marine bunkering in its expansion efforts.

Public opposition to new LNG facilities, particularly large storage facilities, in the U.S. continues to be strong and manifests itself in “NIMBY” (“Not in My Back Yard”) opposition and state/local and federal siting proceedings. In part, this opposition is rooted in an incomplete understanding of LNG, hazards that large LNG storage facilities represent, and hazard mitigation measures associated with the design and operation of LNG facilities.

Interestingly, Canadian projects appear to have experienced fewer obstacles. While the need for additional stakeholder engagements, such as involvement of First Nations communities in project planning and development, is an additional effort, involvement of such communities can increase understanding of the project. In addition, the existence of fewer obstacles in Canada appears to be a result of more frequent engagement of economic and safety regulatory authorities in periodic reviews of projects, in contrast to U.S. projects where periodic reviews stress peak shaving operations and safety.

3 Drivers and Changes in the Industry

The new functionalities identified in Chapter 2 have many different drivers. Whilst most opportunities have multiple drivers, the functionality archetypes outlined above can be associated with one key driver. These opportunities are either business-driven, whereby change is initiated by the terminal in order to enter a new market segment or adapt to market changes, or stakeholder-driven, whereby the terminal needs to adapt to the changing demands of customers, suppliers or regulatory bodies.

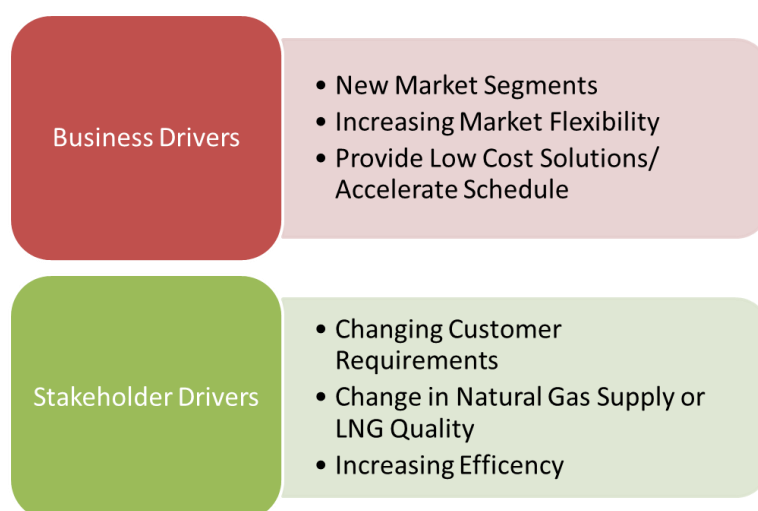


Figure 10: Drivers for adding functionalities vary between terminals but can be broadly classified in recurring themes.

3.1 Business Drivers

Business drivers and changes in markets or technologies, as well as other factors, provide major incentives causing project operators to consider functional changes.

3.1.1 New Market Segments

To increase profitability, all parts of the LNG value chain have had to consider entering new market segments to increase sales of existing products or add new products to their product slate. Out of the key value chain components considered in this report, these changes are most pronounced for LNG import terminals. Here, the emergence of a downstream LNG network in recent years has required the LNG value chain to extend beyond the traditional end point.



In LNG Export Terminals, market changes have made it more economically attractive to extract new products from the feed gas.

3.1.1.1 Product Extraction

Typically, one of the key design decisions in the development of an LNG export terminal is the inclusion of facilities to extract components such as NGLs from the feed gas. For example, if the feed gas is expected to have a significant quantity of propane and/or butane, and a suitable market exists, then fractionation facilities may be included to separate and process these components into marketable NGLs. Even if such facilities have not been included in the initial design, a changing market may well make the extraction of NGLs attractive.

This is also the case for Helium. Since the early 2000s, the demand for this element has grown dramatically. Helium is used extensively as a cryogenic cooling medium for MRI scanners and NMR spectrometers. It is also used to detect leaks in the automotive industry and to create an inert atmosphere for making semiconductors. Whilst Helium is the second most abundant element in the universe, it is rarely found in sufficiently concentrated quantities to be economically viable. However, Natural Gas often contains a non-trivial Helium concentration that will be further concentrated in the End Flash Gas of the liquefaction process. Therefore, the price of Helium increasing, it is now often economically attractive for LNG Terminals to extract and purify the element.

3.1.1.2 Truck Loading

Truck loading facilities have been added to many import terminals to provide LNG to customers in smaller quantities. For example, in regions where there is no existing pipeline infrastructure, LNG can be transported by road to a satellite station where it is then regasified and supplied to commercial and residential consumers. As pipeline construction can be a costly and lengthy process, the supply of gas to remote communities through LNG can be used to develop the market until the network is profitable, or used as a permanent solution if it never becomes profitable. Trucking of LNG can also be used to cover delays in pipeline construction.



Another reason for the addition of truck-loading facilities is to supply LNG as a fuel for transport. Used in trucks delivering goods, LNG has the potential to offer fuel cost savings when compared to conventional diesel. It can also reduce Sulphur emissions, particulates and nitrogen oxides, and help reduce greenhouse gas emissions from production to use.

As LNG Import Terminals are located near populations where demand for LNG as a fuel is higher than Export Terminals, they are ideally placed to enter this market. Truck loading at import terminals is viewed as an extension of services and functionality, and this activity has received varying emphasis in implementation. For example, at the Lake Charles terminal, in Louisiana, U.S., truck loading was removed as a part the terminal's transition to an LNG export facility.

Historically, truck loading at peak shaving facilities served a traditional function, whereby overall LNG strategies included the use of liquefaction capacity to serve satellite LNG facilities as well as peak shaving storage. However, with the expansion of markets into merchant gas operations and transportation applications, renewed interest has emerged in truck loading at peak shaving facilities to serve these new market functions.

3.1.1.3 Bunkering

In addition to supplying LNG as a fuel for road transport, LNG Import Terminals may also consider supplying LNG as a bunker fuel to ships. This is rapidly becoming a reality due to air pollution constraints combined with the significant market opportunity provided by the large volumes of LNG which can be sold.

Indeed, the benefit of using LNG as a marine fuel is that it is clean and cost effective in comparison to the conventional fuels (such as Marine Gas Oil, Fuel Oil, etc) currently used to supply the majority of ships.

For instance, compared to heavy fuel oil, LNG can decrease nitrogen oxide emissions by 85%, carbon dioxide emissions by 30%, and particulate matter emission by 90%. Therefore, LNG

allows operators to meet the requirements set out by the establishment of SECAs (Sulphur Emission Control Areas).

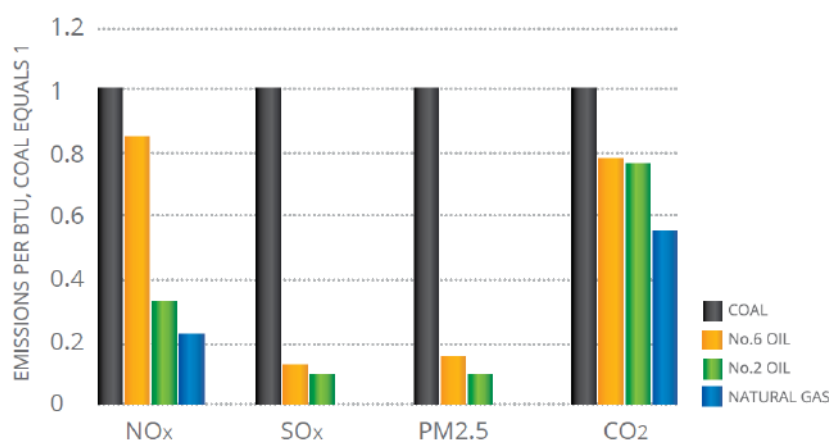


Figure 11: Not only is natural gas the cleanest hydrocarbon fuel source in terms of CO2 emissions it also has significantly less NOx emissions and virtually no SOx and particulate emissions.

LNG Import Terminals which have invested in bunkering facilities have the opportunity to enter the growing LNG-for-Transport market, increasing terminal utilization and adding a new revenue stream.

Similarly, LNG peak shaving facilities also stand to gain from the growing bunkering market. Where such facilities are located adjacent to, or in the proximity of, navigable waterways, peak shaving operations may undertake modifications to serve vessel bunkering.

A chief advantage of using peak shaving facilities for bunkering is the pre-existing LNG storage capacity, which minimizes or eliminates barriers associated with siting new storage facilities. However, despite this advantage, adding bunkering operations to peak shaving facilities does present some technical challenges. This includes the difficulties involved in installing cryogenic pipelines from the peak shaving facility to the bunkering operation (i.e. the fuelling point). There are also regulatory challenges (discussed in greater detail in Chapter 4) which include the need for the facility to seek new approval for the change in use of LNG storage. Whilst the storage tanks were previously approved for the peak shaving function, new permitting is required for their use in the new function of bunkering.

3.1.1.4 Training

As the LNG Industry continues to grow, new players are entering the market. These new entrants may have limited experience of operating LNG terminals. This presents the opportunity for experienced terminal operators to use their knowledge and facilities to create a new business using existing facilities, namely LNG training. This fills an important gap in the market, since there are very few other places where trainees can gain experience in Terminal Operations using LNG.

Most terminals already provide their own in-house training for personnel in terms of safety, maintenance, emergency response and operation. The equipment and facilities required for these courses can be utilized to carry out similar training for other terminals operators.



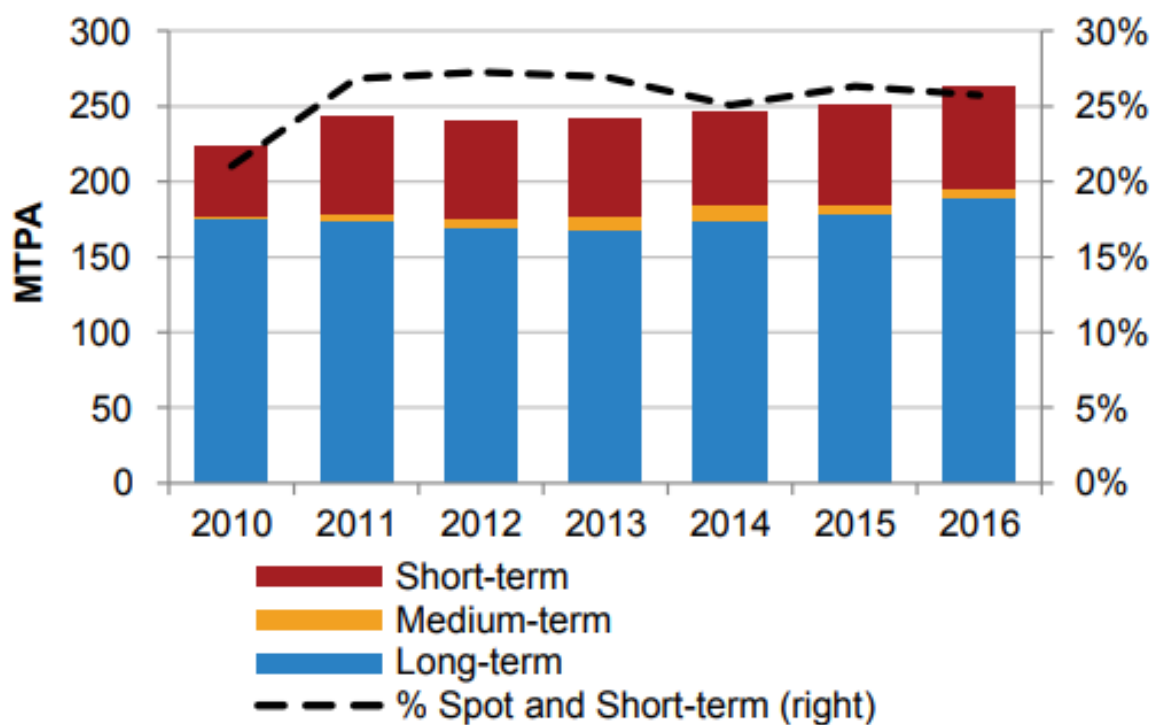
Figure 12: LNG Firefighting training at Fos Tonkin LNG terminal, France, Elengy, Engie Group
Photo courtesy of ELENGY - EVRARD GUES

Table 1: The 4 themes identified in this report have several typical archetypes associated with them. In the table below, the typical primary business driver for these archetypes is identified by a shaded circle. It is noted that many functional changes will have multiple drivers.

Themes -->		Export Terminals				Floating Facilities				Import Terminals										Peak Shaving	
Archetypes -->		Accommodate new feed gases	Product Extraction	LNG quality adjustment	Export to Import Conversion	Redeployment of FLNG	Redeployment of FSRU	conversion to FSU / FSRU	conversion to FLNG	Breakbulk of LNG		Shipping Services		Increased Efficiency		Accommodating New Carriers	Quality Adjustment for Sendout Gas	Training	Import Conversion to Export	Breakbulk of LNG	Direct Fueling of Vehicles
										Truck Loading	Bunkering	Reloading/Trans-shipment	Gasing Up/Cool Down	BOG Management	Cold Utilization	Expanding Jetty and Storage					
BUSINESS DRIVERS	New Market Segments		●							●	●							●		●	●
	Increasing Market Flexibility											●	●			●					
	Provide Low Cost Solutions/ Accelerate Schedule							●	●												
STAKEHOLDER INFLUENCED DRIVERS	Changing Customer Requirements					●	●														
	Change in Natural Gas Supply or LNG Quality	●		●	●												●		●		
	Increasing Efficiency													●	●						

3.1.2 Increasing market flexibility

As the LNG market has grown, a spot market for trading has developed. This short-term trading has increased due to the emergence of portfolio traders. However, to be able to take advantage of this growing market, LNG Import Terminals need to be able to accept LNG carriers of different sizes and may also need additional storage facilities to accept cargos which are not part of long term scheduling.



Sources: IHS, IGU

Figure 13: As the LNG volumes traded in recent years has increased, there has also been a rise in the proportion of short term and spot trading. To capitalize on this emerging market sector, terminals will often need to add new functionalities.

3.1.2.1 Reloading/Transshipment.

Reloading services are an attractive addition allowing LNG Import Terminals to develop new LNG routes. This is done using intermediary LNG terminals providing flexibility and new possibilities for existing infrastructures. The addition of reloading facilities also allows for the optimization of transportation costs using large LNGCs to transport LNG from liquefaction plants to intermediary terminals. Here, this cargo can be split and reloaded onto smaller LNGCs for distribution to smaller consumers, thus optimizing the logistics chain.

Some terminals also offer a transshipment service, which is in several cases more efficient than unloading/ reloading, since it minimizes the lay time duration for the two ships. As the LNG is moved from one vessel to the other, the total operation time is minimized. Operation costs, such as electrical consumption, BOG generation or Nitrogen usage, are also lower.

The main advantage of performing transshipment at the terminal as opposed to in open sea, which is more common for instance for oil, is that operations can be undertaken with less public risk and without any environmental impact. Whereas harbour environmental conditions associated with wind speed or wave action are usually lower, the control mechanisms requirements are always more rigorous.

From a terminal's point of view, reloading or transshipment makes their facilities more profitable, since terminal equipment, historically designed for unloading use only, is now used for additional purposes.



Figure 14: View of "Ben Badis" and "Gemini" LNG tankers during first LNG transshipment between two LNG tankers at Montoir-de-Bretagne LNG terminal the 7th of August 2013, France, Elengy, Engie Group – Photo courtesy of ENGIE / BESTIMAGE / WERDEFROY YANN

3.1.2.2 Gassing up & Cool Down

Traditionally gassing up and cool down is carried out at an LNG Export Terminal. However, Export Terminals often have limited berth availability. Therefore, to minimize the time spent at the LNG Export Terminal berth, there is an opportunity for LNG Import Terminals to offer these services. Additionally, LNG Import Terminals are often near shipyards where LNG Carriers will undergo drydock, and therefore ideally located to offer this service.

Terminal facilities are also more adapted to smooth gassing up and cool down than liquefaction plants, since reloading flowrate is lower in a receiving terminal. This niche activity allows receiving terminals to make their facilities more profitable and optimize the use of their jetty.

3.1.2.3 Modification of Jetty and Storage Facilities

LNG storage tanks are often a significant part of the initial investment in the construction of an LNG Import Terminal. Therefore, when storage is initially built, care is taken to find the optimum balance between cost and ullage. In addition to cost, the size of LNG storage may also be dictated by plot restrictions, government agreements, and construction technology of the time.

However, with the recent growth in LNG volumes traded and the addition of new market sectors, many terminals have found the need to enhance LNG storage volume. There are no practical means to increase the storage size of an existing tank, but many sites have considered building new tanks if plot space allows or demolishing older smaller tanks and replacing them with new larger tanks. Increasing LNG storage capacity will expand the terminal's operating range and improve the flexibility involved in receiving and sending out LNG. For example, a larger storage capacity can allow for the acceptance of LNG carriers larger than before.

For users of the terminal for regasification (the user is not necessarily the same as the owner and the operator of the terminal), increasing the LNG carrier size has been vital to reducing the transportation cost. Therefore, for terminal owners the expansion of jetty and receiving facilities are an important functionality enhancement.

3.1.3 Providing a low-cost solution and accelerating schedule

The introduction of new larger and more efficient LNGCs has led to a surplus of older vessels which are available for new roles. This emergent surplus has coincided with an upward trend in CAPEX, schedule and permitting challenges for new onshore LNG terminals.

The conversion of retired LNG carriers into floating terminals (FLNG/FSU/FSRU) provides an opportunity to develop projects with a substantially lower unit cost compared to new-build offshore or land-based facilities. This is because the cost of building new LNG vessels or onshore LNG tanks can be eliminated. The modification costs required to allow the LNGC to be used as an FSU are normally relatively minor. Typical changes may include additional BOG management capacity and the addition of vaporizers.

For LNGCs to be converted into FLNGs, liquefaction modules need to be added to the topside design. The type of equipment required is typically dependent on the feed gas composition. When the feed gas composition requires relatively little processing (for example, if it is relatively lean and has few contaminants), then the equipment count is lower. It is in these cases where FLNG using a converted LNGC can be attractive. For example, this could occur when pipeline quality is to be liquefied. Utilizing LNGCs also allows for schedule acceleration since they eliminate the need for the construction of onshore LNG tanks, which are often on the critical path for LNG projects. In the case of LNG Import Terminal projects, using an FSRU can often allow for the development of a small gas market. The FSRU can then be replaced with a larger Onshore Terminal once the market has grown.

As highlighted in section 2.2., building speculative vessels may be easier as a conversion project compared to new-build. Although some project-specific modifications may be required for the deployment of these vessels, they provide an opportunity to further accelerate project schedule and reduce project unit costs. This may be interesting for gas reserve owners who are looking to

quickly develop an offshore (stranded) asset (i.e. FLNG), enter a new market (i.e. FSRUs) or develop a hub/breakbulk facility (i.e. FSU).

The extent to which LNGC conversion projects can offer a schedule saving over the course of an onshore development is project- and location-specific. However, the risk of schedule delays as well as cost overruns is likely to be reduced because the vessels are converted in shipyards. Shipyards have a good track record of delivering major projects on time and on budget compared to plants which are constructed onshore. The latter frequently experience delays as result of limited infrastructure, limited resources and extreme weather conditions.



Figure 15: The Golar Freeze LNG Carrier, which was converted to serve as an FSRU in Dubai. Photo courtesy of Shell.

3.2 Stakeholder-influenced drivers

Changes in stakeholder needs and opportunities represent additional drivers for functionality changes at LNG facilities. To a great extent, these drivers are outside of the control of LNG facility operators and require a clear understanding of the changing environment faced by stakeholders.

3.2.1 Changing Customer Requirements

As the LNG industry has grown and developed, the needs of the customer have also developed. This has created the need for the components of the LNG value chain to be able to respond to what the customer requires. For example, the LNG industry now transports LNG in both larger and smaller units than in the past. This has led to the need for terminals to make adaptations to LNG receiving facilities to accommodate the full range of carriers in the LNG fleet.

Another way the industry has demonstrated flexibility is through the redeployment of floating facilities. This relatively new addition has occurred when project needs have changed and floating facilities have been redeployed.

For peak shaving facilities, historical trends have demonstrated a reduced need for peak shaving send out, which may be due to a variety of factors, including increased pipeline capacity to serve peak demands and warmer temperatures reducing the need for weather-sensitive send out. Generally, this may be perceived as a reduction in customer service requirements. However, supply/demand balancing is highly subject to transient influences such as temperature extremes, making a general statement about the reduced need for peak shaving services difficult to justify in many cases.

3.2.1.1 Redeployment of FSRUs

One of the advantages of FSRUs is that they can be readily redeployed if business scenarios change. For example, for many countries preparing to access the LNG market, initial volumes of imported gas may be too small to justify the cost of building traditional onshore infrastructure.



According to Wood Mackenzie, 80% of countries importing their first LNG in 2014-2017 will opt for FSRUs.

The inherent flexibility of FSRUs means that owners can then decide to build permanent onshore facilities once the market has developed or, if the market does not develop as planned, the project can be stopped and the FSRU can be redeployed to another project. Alternatively, operators may choose to keep the FSRU as a permanent solution.

3.2.1.2 Redeployment of FLNG

Whilst we are still in the early days of FLNG development, one of the key design features of FLNG is its ability to be redeployed. Whilst the intent is redeployment once a gas field is depleted, allowing for the development of smaller stranded gas fields, an FLNG can also be redeployed if a business decision is taken to stop the original FLNG project. As mentioned previously, this has been seen in the Caribbean FLNG project, which was cancelled after changes to the domestic gas market in Colombia. The FLNG is now available to be redeployed to a new project.

3.2.2 Change in Gas Supply and LNG Quality

In LNG Export facilities, the process design is made for the predicted feed gas. However, over time the gas composition received from upstream facilities can change, either due to depletion of the original gas field or due to the addition of new gas fields in so called “back-fill” projects. Often, these feed gases will have a different composition and changes to the LNG facility may be required in order for the terminal to continue producing LNG of similar quality and maintain production rates.

With the rise in the number of LNG exporting countries, there have also been consequences for LNG importers. Given that LNG from different sources will have different compositions and heating values, Import Terminals have had to adapt to accommodate these new products.



However, the biggest change faced by the industry in recent years, is the complete transformation in function of some terminals. This has occurred, for example, in the U.S., where the shale gas boom has led to the complete reversal in flow from LNG Import to LNG Export. Examples of conversion from LNG Export to Import have also been seen but are much less common.

As noted in Section 3.2.1, the reduced need for peak shaving services is due, in part, to the expansion of pipeline gas deliverability. This effect is most pronounced in the north east of the U.S., where transmission pipeline expansion and the development of regional gas supplies in tight geologic formations have helped alleviate historical physical constraints on natural gas deliverability.

3.2.2.1 Accommodation of New Feed Gas

When designing an LNG terminal, predictions of likely feed gas compositions are made based on the available information about the upstream gas fields. However, over time, the feed gas to the plant may change due to many factors. As fields become older, techniques may be applied to try to maintain production from a depleting gas field. These techniques may lead to increasing volumes of liquid hydrocarbons being found in the supply to the plant. Feed gas to the plant may also change as new fields are developed with different compositions to the fields initially developed.

Variation in feed gas supplied to a site can have many effects on the site which need to be addressed. For example, if the feed contains an increasing amount of liquid components the existing NGL removal units may be undersized and become a bottleneck leading to reduced production. If the concentration of contaminants in the feed gas (e.g. H₂O, CO₂, H₂S, etc.) increases, then the Gas Treating section of the plant may also become a bottleneck to production.

A related consideration with respect to feed gas is the need to accommodate differing market demands for LNG energy content. In this case, for a fixed feed gas quality, market requirements



may set different limits on the quality of LNG received. In the case of Qatargas, development of its megatrains liquefaction operations has had to take into consideration the lower Wobbe Index and HHV limits set by the U.K. and the U.S. (typically lower than 42 MJ/m³) relative to limits in other receiving markets. Specific trains were designed and optimized to meet these lower Wobbe Index and HHV markets (lean LNG). As the market for lean LNG has shifted with U.S. imports dropping off, Qatargas (and RasGas, its partner operating company before the merger of the two entities completed in January of 2018) developed “Common Lean Storage” and “Common Lean Loading” facilities to address the need to integrate operations which serve leaner markets.

3.2.2.2 Export to Import Conversion

LNG Export Terminals are built in locations where the natural gas reserves are greater than local demand. This creates an opportunity for the country to monetize the gas through export to locations where there is high demand. However, in-country circumstances may change over time. For example, depletion of natural gas reserves, an increase in domestic gas demand or political instability may lead to an LNG terminal no longer being required. However, the components of the LNG facility can still prove to be an asset. If a net exporter of LNG becomes an importer of LNG, then the conversion of the terminal can become an attractive option.

There are many aspects of an LNG Export Terminal which can be reutilized in an Import Terminal. For example, the LNG storage tanks, loading lines, and jetty are some of the high CAPEX items associated with an LNG Import Terminal which can be reused in a conversion project. Whilst modifications to pumps, valves and piping will need to be made, there remains a significant cost saving in terminal conversion.

3.2.2.3 Import to Export Conversion

Within the North American gas market, a major shift in gas supply conditions has incentivized a transition of purpose-built and sanctioned LNG Import Terminals to LNG Export Terminals through the addition of liquefaction facilities. Virtually all LNG terminal projects which have completed construction or passed FID at the time of writing of this report have investigated or



implemented a transition to LNG exports while maintaining their capacity to serve as import facilities. In the U.S. in particular, a sea change in supply and demand balance has been facilitated by the increase in hydraulic fracturing production technologies. These technologies extract non-associated natural gas from previously technologically-infeasible “tight” geologic formations, most commonly involving impermeable shale formations. With the exception of eastern Canadian import terminals (principally the Canaport facility in New Brunswick), anticipated Canadian momentum in development of export facilities has been focused on western Canadian “greenfield” projects. Here, development has been slowed by world gas market softness and associated infrastructure (e.g. gas pipeline) development constraints.

The construction of the sanctioned LNG import facilities in the U.S. and Canada was motivated in large measure by widely-publicized estimates of a shortfall in domestic natural gas supply. In 2003, U.S. Federal Reserve Chair, Alan Greenspan, responsible primarily for U.S. monetary policy, forecasted a shortfall in U.S. natural gas supply and a resulting doubling of equilibrium prices for U.S. natural gas. Chairman Greenspan’s testimony to the U.S. Congress followed many experts in alerting U.S. market players (the U.S. being the world’s largest gas market) to the need for expanding LNG imports and import facilities beyond the four constructed Import Terminals in various states of readiness at the time.

The North American gas industry was swift in exploring the development of new LNG import facilities. By the beginning of 2006, U.S. regulators had approved 12 new onshore and 3 offshore LNG receiving terminal projects. Ultimately, six new U.S. receiving terminal projects and one Canadian project were put into service between 2008 and 2011. When North American gas surplus conditions reached the recognition of market players, the transition of focus to LNG exports launched many new projects toward the regulatory application and pre-FEED stages. Estimates of U.S. exports reached as much as 66 MTPA as late as 2017. Proposed export facilities are summarized in Figure 16, produced in August 2017 by the U.S. Federal Energy Regulatory Commission (FERC), which principally regulates onshore LNG safety of U.S. LNG facilities engaged in the “interstate” and international LNG and regas trade.

North American LNG Export Terminals Proposed

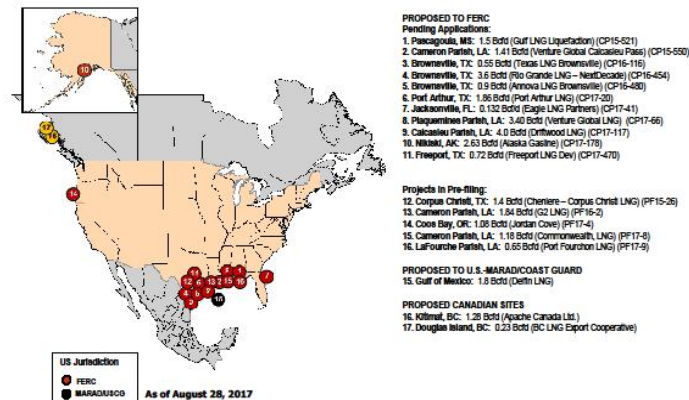


Figure 16: With the shale gas revolution in North America, there has been a raft of projects proposed for development in both the Gulf of Mexico and British Columbia.

Five U.S. receiving terminal projects have implemented or proposal liquefaction trains to support LNG exports including:

- Sabine Pass LNG, completing 9 MPTA of liquefaction capacity as of early 2017 and planning an additional 4.5 MPTA under construction for proposed start up in 2019
- Cove Point LNG, with 5.25 MPTA under construction for proposed start up in 2017
- Elba Island LNG, with 2.5 MPTA under construction for proposed start up in 2018
- Cameron LNG, with 12 MPTA under construction for proposed start up in 2018
- Freeport LNG, with 10.2 MPTA and an additional 5.1 MPTA under construction for proposed start up in 2018-19 and 2019, respectively.

The volumes reported here reflect capacity under construction only and exclude additional capacity planned (i.e. pre-FID). Current information on Canadian project development (Canaport) is not available at this time.

Expansion of U.S. exports was forecasted by the U.S. Energy Information Administration to follow the trend shown in the figure below through the third quarter of 2017.³

³ Zaretskaya, V. and, K. Tsai, "U.S. Liquefied Natural Gas Exports Have Increased as New Facilities Come Online," Today in Energy, U. S. Energy Information Administration, 7 December 2017.

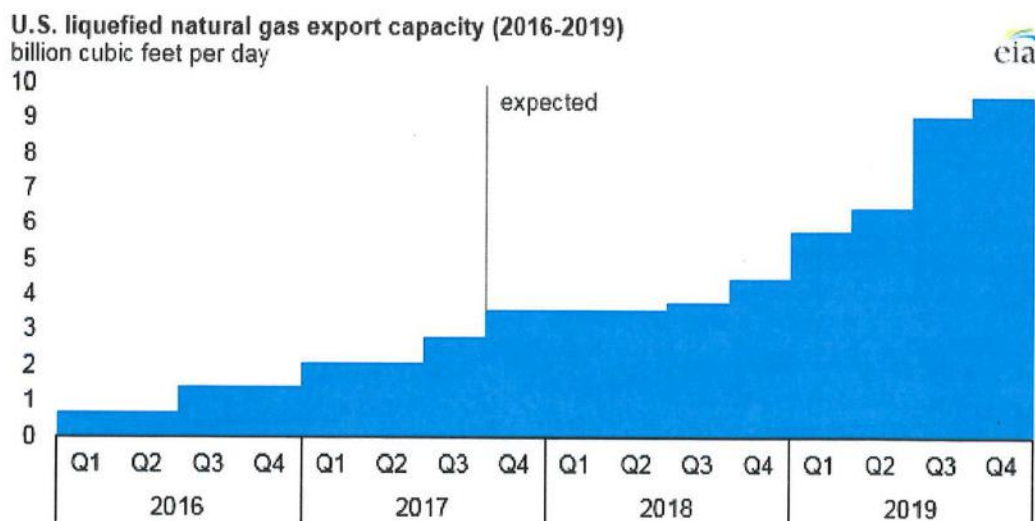


Figure 17: LNG Export Capacity is forecasted to grow rapidly in the coming years as conversions of Import Terminals and new build LNG Export Facilities start to come online.

Aside from Sabine Pass exports, an Export Terminal in Kenai, Alaska, has historically exported LNG to Japan since 1969, with a suspension of exports in 2015. Of total North American exports, most LNG is shipped to Asian countries as shown in the plot below.⁴

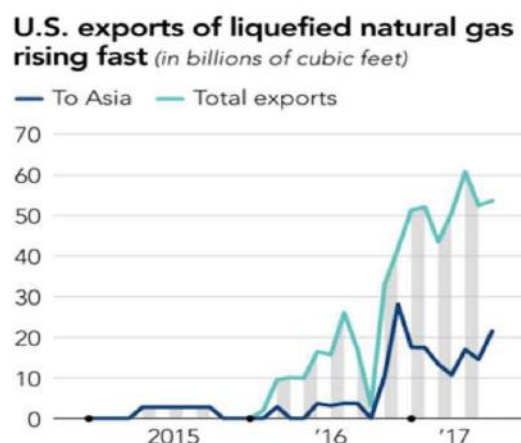


Figure 18: The rapid rise in US LNG Exports in recent years has a significant component of sales to Asia.

The principal driver for this North American activity is LNG demand around the world, mainly in the Pacific Basin and the European market. Generally, the volumes of LNG capacity under construction have been pursued without firm offtake commitments in anticipation of general demand being high enough to absorb all North American supply. However, in the last two to

⁴ Institute for Energy Research, Canada, "U. S. to Become a Major LNG Exporter," 1 November 2017.



three years, the softening of energy demand generally coupled with LNG demand growth (now at 0.5% annually) has put increased pressure upon project development and schedules. This has required more careful alignment of CAPEX commitments to expectations of a global LNG market recovery, particularly as world economies recover and natural gas gains market share relative to other fuels. Additionally, current market conditions are likely to have motivated delays in FIDs for other likely entrants design-built as LNG receiving terminals.

3.2.2.4 *Quality adjustment for send-out gas*

LNG quality adjustment is often carried out at Import Terminals by blending to maintain the heat value level. Natural gas has different components depending on the place of production. With the move away from traditional long-term supply, importers often receive LNG from a different location. This product therefore has a different calorific content. If natural gas with a calorific value which does not meet customer specifications is supplied, damage may occur in end users' gas facilities. Therefore, terminals have had to add facilities to control the heating value in order to satisfy requirements by injecting LPG/N₂ to the natural gas supplied.

3.2.3 *Improving Efficiency*

In order to maximize profitability, it is important to ensure that all parts of the LNG value chain are utilized with maximum efficiency. As margins have been squeezed, operators have looked for new ways to minimize product loss. Many terminals have seen lower than design send out. This low send out typically means that the plant operates less efficiently as many equipment items are operating far from their design point.

3.2.3.1 *BOG Management*

As heat is transferred into the LNG Import Terminal from ambient surroundings, LNG will vaporize and become boil-off gas. This boil-off gas must exit the terminal. Typically, the gas will be sent out to customers using BOG compressor or recondenser. However, in low send out scenarios, where regasification is lower than the design conditions, it may not be possible to send this gas to the customers. This can pose a problem during the unloading of LNG carriers, which leads to a



significant additional boil off gas. Additionally, as LNG carriers have become larger, unloading rates have increased which has led to increased BOG volume flows.

The only other option for many terminals is to route the excess boil off gas to flare. However, not only is this a loss of gas which could be sold to the market, it is also harmful to the environment. Therefore, many terminals have invested in additional equipment to increase their BOG management capacity.

3.2.3.2 Cold Utilization

The cold energy which can be captured from the vaporization of LNG is typically rejected into the surrounding environment. However, to improve the overall efficiency of the terminal, this energy can be recovered and used as a cold source. By utilizing this cold LNG energy, businesses will be able to reduce the power consumption of refrigeration equipment, which can be located at the terminal or in a nearby plant.

Generally, users of cold LNG energy pay a usage fee to the suppliers of the energy based on consumption. The tariff for cold LNG energy is allocated by the user and supplier. In other words, by using cold LNG energy, the user can reduce electricity costs beyond the market price, even when paying a cold energy fee.

In many cases, it is also possible to return the heat transfer fluid back to the LNG Import Terminal as a warm source to improve the efficiency of the LNG vaporization process.

4 Opportunities and Challenges for Enhancing Facility Flexibility

The introduction of new functionalities into an LNG facility presents many opportunities and challenges. Whilst some of these are unique to individual facilities, there are many common themes in the opportunities and challenges associated with introducing new flexibilities to terminals.

For example, many of the enhancements are dependent on the development of new markets. Typically, terminals will be challenged with finding the optimum point to invest in new infrastructure when the market in which they are entering is still small but has the potential for significant growth. Whilst being an early entrant into a growing market can offer significant opportunity, the challenge of timing an appropriate CAPEX investment can pose difficulties. This can be seen, for example, when adding bunkering or truck loading facilities to an LNG terminal.

Another common challenge for adding functionalities to an existing facility is the availability of plot space. In many cases, LNG Import Terminals and peak shaving facilities are located in areas where land space may be at a premium, such as industrial areas near major cities. This can pose a challenge when looking to add additional equipment to the complex. Whilst LNG Export Terminals are typically located in areas where land is more readily available, the plot space requirements for adding new LPG or Helium extraction facilities are often large and have associated separation distances from existing process units. These requirements can then pose challenges for the terminals, particularly if changes in functionality were not considered in the design phase.



4.1 Export Facilities

4.1.1 Opportunities

As discussed above, the most typical opportunity available to LNG exporters is to optimize their product slate when the feed gas to the complex changes. Whilst there are challenges associated with this (as outlined below), there can also be significant benefits. For example, if the feed gas to the plant becomes significantly richer, containing an increased number of non-methane hydrocarbons, then this represents an opportunity for the asset. If the richer gas can be processed by the existing equipment, then LNG production can be increased. It should be noted that a richer feed gas can be liquefied with a lower specific power and therefore LNG production can often be achieved. However, the asset may choose to benefit from extracting the heavier hydrocarbons and selling them into more profitable markets.

Opportunities may also exist in LNG terminals to increase their energy efficiency. With an increasing global focus on reducing CO₂ emissions, there is often increased scrutiny on the emissions of existing LNG facilities. Whilst reducing emissions can pose a challenge to facilities, there may also be an opportunity to reduce operational costs. For example, small plant projects such as optimizing power generation and fuel gas systems can reduce the amount of feed gas used as fuel gas and, therefore, liberate gas to be produced as LNG.

4.1.2 Challenges

Incorporating new flexibility and functionalities at LNG Export Terminals is typically somewhat constrained by the lack of customers in nearby markets. This will often limit opportunities for adding services such as truck loading or bunkering. However, terminals have needed to show flexibility to be able to meet the growing demand for LNG and to extend asset life, particularly when faced with changing feed gas quality.

Whilst the composition of feed to an LNG plant will vary depending on changes in the upstream gas field, the composition in the early years of plant life will largely fall within the operating window determined during the design phase of the project. However, over time, with the



addition of new feed gas sources or the depletion of older fields, the feed gas composition may change beyond the original design envelope. If this change introduces more contaminants such as CO₂ or Sulphur, then the Gas Treating facilities may have to be modified to ensure that the process specifications can still be met. Ideally, changes made to the facility will have a minimal impact on ongoing operations. For example, increased CO₂ may be accommodated by changes to the solvent used in the acid gas removal unit. This is a relatively easy modification that, with sound engineering judgement, could be carried out during a turnaround window. However, if the increase in contaminants requires physical modifications or addition to existing facilities then it may be difficult to achieve this without extending the duration of the turnaround. This can pose a significant challenge to the project as extended periods of non-production will have significant financial implications.

As outlined in 4.1.1., a richer feed gas can present a significant opportunity for a terminal to increase sales of valuable LPGs, or increase LNG production. However, again there can be bottlenecks in the existing processing facilities. For example, existing NGL fractionation columns may be loaded more heavily than what was originally designed for. Whilst physical modifications to column and vessel internals can be carried out, this may require significant investment and operational downtime.

Therefore, it may be possible for operational adjustments to accommodate the new feed. Whilst these changes will require study work and may require checks with vendors and licensors, they could minimize physical modifications to the hardware. Such changes may include adjusting process temperatures, adjusting flowrates or partially bypassing certain units. It should be noted that these modifications should be considered for their impacts on all connecting parts of the plant to ensure that there are no unintended consequences to other operating units.

In the event that the asset has no NGL/LPG extraction facilities, then it may be necessary to add these to the facility in order to meet LNG sales specifications.

If modifications are not made to accommodate changes in the feed gas then it will still be possible to continue production. However, to allow product specifications to be met, the LNG production rate is likely to need to be reduced.



Figure 19: Oman LNG has recently undertaken modifications to process a wider range of feed gas compositions in light of new upstream developments. Photo courtesy of Shell and Khalil

4.2 Floating Facilities and Logistics

4.2.1 Opportunities

Given that there has been a step change in the size and efficiency of LNGCs, there is a significant opportunity for ship owners to utilize older LNGCs to provide storage in both new and existing LNG projects. This allows for older LNGs, which are often less efficient and therefore costlier to operate, to continue to be used when they would otherwise no longer be in service as LNG carriers.

As previously discussed, LNGC conversion projects provide an opportunity for substantially lower unit cost projects and are quicker to deploy and develop. This is one of the main drivers for the conversion of retired vessels. Compared to new-build offshore vessels, the modification costs required to allow the LNGC to be used are normally relatively minor. Another opportunity for converted LNGCs is redeployment to a different location if an LNG project is delayed or cancelled. This reduces the risk of sunk costs to the facility owners in the event of projects being cancelled after FID has been taken.



Figure 20: Prelude FLNG sails away from the shipyard in Goeje en route to the gas field 475km north north-east of Broome.
Photo Courtesy of Shell

4.2.2 Challenges

In order for a converted LNGC to be deployed economically as a FLNG terminal, there needs to be a restricted window of feed gas compositions. This is due to limited available space for gas processing modules and limited storage space for condensate or NGL products.

Regulations for floating LNG facilities also vary significantly between regions, which can impose deployment challenges and less advantaged project economics.

In some regions, floating facilities are required to be sent to dry dock for inspection every five years. During this time, a replacement vessel needs to be found in order to continue facility operation. This may cause potentially high charter rates or a period of downtime, which results in a loss of revenue.



Figure 21: The FSRU *Independence* was delivered in 2014 to diversify Lithuania's gas imports. Photo courtesy of AB Klaipėdos Nafta at Wikimedia Commons



The use of a converted LNGC in projects may also lead to challenges when the resource holder desires a significant amount of local content in a project. As most of the manpower required to convert an LNGC into an FSRU, FSU or FLNG is carried out in a shipyard, the opportunities for local workers to be involved in project construction is significantly reduced. This driver may cause governments to pursue a traditional onshore development over a converted LNGC project.

Another challenge to the conversion of LNGCs into floating export or import facilities, is the limited deck space available for the addition of processing facilities and gas or LNG transfer arms to the topside design.

Whilst it has been proven that a regasification plant, together with the LNG loading and gas export system, can be easily fitted on the main deck of a Moss LNG carrier, the space on the hull of Moss LNGCs is limited for FLNG conversions. To fit the feed gas treatment facilities and liquefaction facilities on top of the hull, the hull can be extended via the addition of sponsons. These are floating side structures that are installed on the side of the tanker and provide space for the additional equipment as well as stability to the floating structure.



4.3 Import Facilities

4.3.1 Opportunities

The concept of using Import Terminals as an LNG Hub - a single location in which LNG is unloaded, stored, reloaded, redistributed and reused - gives these terminals the opportunity to be in the middle of an extended LNG chain rather than at the end of the conventional LNG chain. Import Terminals are now a connection point between the conventional upstream LNG chain and several new smaller downstream chains, thanks to their new functions.

Changes in Import Terminals allow clients to create and develop new LNG markets, such as the use of LNG as fuel. Already mature in some countries, including the U.S. and Canada, this market is booming in Europe, thanks to the environmental benefits of natural gas compared to other carbon products.

The enhanced functionalities of LNG Import Terminals also make it possible for producers to distribute LNG to a number of countries that were previously unable to access the LNG market because they were located far from producing countries or because they were accessible only by low capacity tankers.

Finally, the use of liquefaction plants and LNG tankers is optimized since they are not linked to a single LNG chain. The entire LNG chain is therefore undergoing a transformation thanks to the evolution of LNG import terminals.

The main lesson learned through the transformation of terminals in recent years is not to restrict the potential for future expansion by building a terminal in too small a site. It is also crucial to predict tie-ins at several locations of the LNG/NG main headers. By predicting these tie-ins, terminals should be able to not only prevent long-term plant closures but also minimize the cost of possible modifications or expansions.



For potential activities which require little capital expenditure (e.g. vessel reloading or ship gassing-up/cool down), it is worth including the required infrastructure from the beginning, even if the market for these activities is not yet developed in the country at the time of building the terminal.

Digital control systems and fire and gas detection systems should be adaptable and scalable in order to accommodate potential additional functionalities. Key equipment as pumps, compressors or loading arms may also have to be adapted so they can meet new demands in an efficient way, minimizing unavailability, maintenance and electricity cost.

BOG management equipment must be sized to deal with the fluctuating gas market, with varied natural gas sendout, while eliminating the need to flare any BOG.

Equipment used for new LNG functionalities, for instance LNG truck loading or LNG barge loading, should be standardized to make trucks and barges compatible at all import terminals and to standardize operators' practices in order to improve the safety of operations.

On the other hand, planning for potential new activities must be balanced with reasonable costs, with the emphasis during terminal design placed firmly on the predicted use and avoiding regret costs.



Figure 22: Carbon Dioxide Liquefaction plant at Senboku Terminal I. Photo courtesy of Osaka Gas

4.3.2 Challenges

The modification of LNG Import Terminals can often require radical changes in the terminal model.

The mindsets of operators are evolving because, through LNG truck loading services, they are now directly in contact with customers and have to respond quickly to their needs.

The way terminals operate is also evolving. The work of a terminal has gone from a static or routine unloading and regasification operation, to a fluctuating dynamic operation linked to daily or hourly LNG market changes, which require reliable and adaptable facilities.

To meet these new requirements, new skills are also needed so people have to be trained. From a maintenance perspective, equipment is required work in conditions different from those set out in the design. This means more inspections and overhauls but also more failures and unavailability. In addition, the utilization of existing facilities increases and must be managed to meet all requirements. In sum, the whole organization must adapt to the new environment.

Terminal facilities should also be designed for several activities, which differ in terms of purpose, availability, reliability and redundancy. In some cases (for example, jetty enhancement for small scale loading), existing facilities need to be adapted. In other cases, it will be necessary to build new equipment, as is the case for truck loading stations.

The decision to invest is also a challenge and, unlike regasification, which is governed by high-income long-term contracts, new terminal activities take place in short-term, spot and lower-income markets. The development of these new markets is less predictable and requires investors to take risks.

In addition, whether large-scale or small-scale, the terminal must remain 100% safe since any incident on an LNG terminal would impact the entire LNG chain and market. Thus, bringing flexibility to the LNG value chain requires not only the flexibility of the LNG terminal itself, but also the flexibility of the people who operate it and the organizations who support it.



Figure 23: Two truck loading bays at Fos-Tonkin LNG terminal: End September 2014, first commercial truck loading. Photo provided courtesy of ENGIE / NEUS / BRUNET ARNAUD



4.4 Peak Shaving

Potential opportunities for functional changes at LNG peak shaving facilities are fundamentally limited by competing sources of natural gas and restrictions associated with the chartered purpose of the facilities. While some new-build projects, such as Takoma LNG in the State of Washington (U.S.), have taken both peak shaving and marine bunkering operations into consideration in their design prior to the FEED stage, the adaptation of existing facilities requires a proper, and often regulatory-approved, balance across the different functionalities.

4.4.1 Opportunities

A key opportunity facing many peak shaving facilities is the expansion of natural gas markets to new service territories beyond the boundaries of the originally-sanctioned peak shaving market area. Taking up this opportunity involves continued use of the public utility business model to extend supply services to other distribution grids and remote end use customers. As discussed in Chapter 3, this can occur where the gas market grows faster than new pipelines can be delivered to meet this new service territory demand. Likewise, some individual end users or end user groups outside of the traditional public utility model may simply be too remote to be supplied by pipeline natural gas in the foreseeable future.

To take advantage of these opportunities, operators of LNG peak shaving facilities with liquefaction and storage capacity in excess of peak shaving needs may need to reexamine their corporate strategies. This involves looking for service territory expansion opportunities and remote customers where natural gas end use represents cost-effective advantages and environmental or other needs external to the pure energy play LNG might provide. These may be non-traditional areas for facility ownership and management to consider and may require a refocusing of basic business strategy.

Additionally, the extension of LNG services to liquid delivery to transportation customers, including fueling land vehicles (on-road and off-road) and marine vessels, represents new market opportunities. Breaking into the transportation fuels market requires some basic



infrastructure modification as well as basic business strategy adjustments. However, if competitive transportation fuel prices and the emissions regulatory environment are forecasted to remain intact in the economic long run, entry into the transportation fuels market may be a logical alternative for consideration. As with the expansion of trucked operations serving new service territories and other traditional end users, entry into the merchant LNG business for providing transportation fuels requires a fundamental shift in ownership and management strategy as well as a re-examination of physical facilities to serve such new functions. In particular, CAPEX decisions on adding liquefaction capacity beyond the traditional seasonal storage replacement need to be made early in the consideration of these alternatives for peak shaving facilities. In some rare instances, storage expansion may need to be considered as well. Nevertheless, it is rarer that the physical facility in-place will be sufficient to support these expanded service opportunities.

The direct fueling of LNG road vehicles is another potential opportunity. This may be the most modest opportunity facing the LNG peak shaving facility owners and operators. Some facilities may have already provided for truck loading for transfer operations that can be adapted to vehicle fueling operations. The simplest implementation of this approach would be for fueling utility vehicles where custody transfer would not be an issue or would, at least, be minimized. Nevertheless, the change-over to dispensing LNG as a vehicle fuel would require some basic, if relatively minor, changes to equipment and standards compliance at the LNG send out for the plant. Some of the technical requirements in international and domestic standards are under development at this time and, in a number of cases, do not anticipate incorporation into a peak shaving facility. As a result, facility ownership and management may need to take creative approaches to adapting requirements from various sources to achieve corporate and local stakeholder acceptance.

4.4.2 Challenges

Challenges facing functional changes to LNG peak shaving facilities include both market challenges and regulatory and public acceptance challenges. Some of these are introduced in earlier report sections but are more fully discussed in this section.

Safety regulatory barriers to the expansion of function and addition of infrastructure are among the most important barriers to functionality changes. Perhaps the most pronounced of these challenges facing expanding the functionalities at LNG peak shaving facilities is in overcoming perceived and regulated safety status and requirements associated with the facility, particularly where safety and regulatory requirements were originally applicable to the peak shaving facility and functionality. In most project cases, some degree of significant modification of the facility is needed to add functionality, most often requiring the addition of liquefaction capacity and its associated footprint.

In other cases, the addition of truck loading facilities and footprint is needed. In rare instances, some additional storage capacity is needed but, more often, the expansion project is based upon existing storage capacity with only higher frequencies of LNG inventory cycling. Regardless of the infrastructural changes, the additional infrastructure and associated higher levels of LNG turnover raise concerns over the public safety of the modified facility. In cases in North America (and particularly the U.S.), LNG peak shaving facilities received waivers from federal citing requirements since the facilities had preceded the promulgation of these requirements.⁵ In those instances, any significant modification to a peak shaving facility approved under those conditions would potentially nullify the waived requirements, effectively requiring the re-evaluation of facility safety with respect to accidental LNG releases and potential vapor ignitions. Few facilities in the U.S. would be able to meet these new requirements once their waiver (referred to as “grandfathering”) was removed.

⁵ 49 Code of Federal Regulations, Section 193.



This is the environment for U.S. LNG peak shaving facilities, regardless of whether the intent of facility modifications is to add functionality or to add to chartered peak shaving capacity. Other, non-U.S., facilities are expected to face similar restrictions, albeit not necessary under national regulatory requirements. Safety requirements aside, a practical safety issue facing LNG peak shaving facilities, regardless of national jurisdiction, is that economic growth surrounding the facilities over time has brought the public into closer proximity to the facility and any potential hazards associated with LNG releases. Adding facility throughput to serve new functions works to increase public hazards as a result, which may be contrary to a wide range of stakeholder interests, including peak shaving facility ownership and management.

Additionally, economic regulatory barriers to expanding functions may be perceived to compete with the peak shaving function. For most LNG peak shaving facility operators (and particularly for those in the U.S.), facilities have been approved by regulatory authorities and funded based on natural gas utility “rate payer” funds. In the U.S., these funding agreements and commitments to serve the peak shaving function are regulated by State regulatory commissions, which may differ in their recognition of the legitimacy of using rate payer-funded infrastructure to serve other non-regulated corporate objectives. As an illustration and in the context of “excess capacity” at a U.S. peak shaving facility, it is uncertain: (1) how “excess capacity” is estimated and, (2) at what cost the non-regulated business interest should repay the rate payers for their initial investment in the facility. Utilities have proposed and have gained acceptance for this consideration in different ways. Chapter 5 provides some examples of cases where this was done. In some cases, it has required spinning off the LNG peak shaving facility to a non-regulated entity and recovering the depreciated cost of the facility to the utility to compensate rate payers, followed by utility contracting with the non-regulated entity for peak shaving services. In other cases, a shared facility approach has been used where virtual storage capacity is split between utility and non-regulated businesses (compensating rate payers in the case of the non-regulated capacity), sharing storage volume and other capacity factors on a proportional basis.



In this virtual storage arrangement, contingency agreements, including interruptible natural gas supply contract clauses, may be implemented to provide assurances that, in all cases, the peak shaving function is provided for. A key risk facing LNG peak shaving owners and managers in this situation is to have an accurate and reliable understanding of the regulatory oversight of the peak shaving function. In approaching the regulatory authority with a proposed revision of the use of the LNG peak shaving facility, the owners and management must have a comprehensive financial and operational approach, clear communications with all stakeholders in the peak shaving function the LNG facility provides, and public trust in the objectives and protections provided in the proposed arrangement.

Uncertainties among general natural gas demand factors present challenges. All new functions involve some degree of market risk. In the case of expanding functionality to serve new natural gas service territory, the primary risk may be the ultimate construction of natural gas pipelines to provide lower cost natural gas services than the LNG peak shaving facility can supply via a satellite facility. In the case of other traditional markets such as power generation with natural gas, the pipeline risk may be even higher since competing gas services via pipeline may better approach wholesale prices. Also in those cases, a risk of fuel switching away from natural gas altogether (as in the case of a coal/natural gas power facility) is tangible and may hinge upon fuel price differential stability. As a result, initial drivers for such projects may need to be risk adjusted in terms of contracting and term commitments. While trucked LNG to these customers can be diverted if market risks arise, alternative markets may be highly speculative.

Additionally, uncertainties within competing fuels markets present market risk. Merchant LNG services to vehicle refueling and vessel bunking operations face risks from at least two sources: instability in fuel price differentials facing the LNG price/technology in the mid-term and LNG supply competition from other sources. As discussed in Section 2.4, market demand for natural gas as a vehicle fuel has been influenced by a mix of emissions performance and fuel price competitiveness. In the wake of dramatic increases in North American supply of natural gas as a result of hydraulic-fracture production and relatively high oil prices, the natural gas price and



emissions performance demonstrated competitive advantages for LNG-sourced natural gas. However, with the penetration of hydraulic fracturing technology in oil production, a significant portion of the price advantage evaporated, leaving natural gas (still in an early phase of introduction as a vehicle fuel) in a more difficult competitive position as a competing transportation fuel. This is coupled with uncertainty over the pace of introduction of more stringent emissions requirements on engines. Here, the LNG peak shaving facilities face a potentially highly competitive fuels market. In contrast, marine bunkering has longer lead times and higher switching costs between fuels and fueling infrastructure and may provide greater certainty. However, LNG peak shaving facilities as a supply source will still face competition from other sources of LNG for vessel bunkering. In all cases, the extent to which LNG peak shaving suppliers can negotiate price and term commitments from fuel customers can help alleviate at least a portion of these risks.

Organizational orientation toward serving the natural gas utility function present non-technical but important challenges. Since LNG peak shaving plays a key (if under-utilized) role in meeting needle peak demands, ownership and management may have difficulty in adapting to the new, competitive market-based functions that it chooses to undertake. In many cases, management may not have direct experience in dealing in these competitive markets and may not be suited to take on that challenge. Additionally, managers who are experienced and knowledgeable about these challenges may have to address potential conflicts with the traditional gas supply interests. From a corporate culture standpoint, the ownership and management must find the appropriate balance and team to execute the new project while meeting their chartered peak shaving roles. Organizationally, and as demonstrated in the case studies in Chapter 5, an appropriate approach might be to spin off the peak shaving plant and operation to a third party and contract with the new ownership for the chartered peak shaving operations. Under that structure, the new management may be better oriented toward serving these multiple functions.

5 Case Studies

In this chapter, you can find a case study for each theme to illustrate the functionality additions which have led to increased flexibility across the LNG value chain. These case studies represent a sample of projects describing functionality changes and are not a complete listing

5.1 LNG Export Terminals

Sonatrach, Arzew, Algeria

In 1964, the world's first base load LNG facility came on-stream in Arzew, Algeria. The *Compagnie algérienne du méthane liquide* (CAMEL or GL4Z) plant exported shipments of LNG to France and the U.K. The plant was steam turbine driven, water-cooled and consisted of three trains using the Cascade liquefaction process with a total LNG capacity of 0.9 mtpa. The project was a joint development between Sonatrach, Shell (the technical advisor) and others.

Since these first trains were commissioned at Arzew, the facility has expanded to include several neighbouring LNG plants. Arzew GL1Z (1978) has six trains; Arzew GL2Z (1981) has six trains; the most recently completed Arzew GL3Z (December 2014) has one train. Over the years, these facilities have seen increasing additions of flexibility and functionalities.



Figure 24: GL3Z facility at Arzew is the latest addition to an industrial complex which first exported LNG over 50 years ago. Photo courtesy of Sonatrach.

5.1.1 Extracting LPGs

The first LNG trains (GL4Z) were built in the mid-1960s. The trains were designed to process gas from the Hassi R'Mel field. The trains in the GL4Z complex could recover condensate after propane pre-cooling but there were no facilities for LPG extractions. When additional trains were added as part of the GL1Z and GL2Z facilities, these were provided with the capacity to recover LPGs from the feed gas.

The new GL3Z complex added in 2014 has the capacity to extract LPGs and condensate from the feed gas. Since the first terminal was built over 50 years ago, the product slate of the Arzew terminals has been significantly diversified to maximize value from the feed gas.

5.1.2 Ethane Extraction

Further to LPG production, the GL3Z facility also has the capacity to extract 300,000 tons of ethane per annum from the feed gas. Sonatrach has also studied options to extract ethane at the GL1Z and GL2Z terminals and to build an ethane cracker which would produce ethylene for use in ethylene glycols and polyethylene. Similar studies have also been carried out for propane as a chemical feedstock. These options would significantly vary the revenue streams of the Arzew facilities. However, to date these plans have not been realized.

5.1.3 Helium Extraction

In addition to the hydrocarbon product slate outlined above, the Arzew facilities also have the capacity to extract helium from the feed gas. In 1995, a two-train Helium extraction facility was added to produce liquid helium from GL2Z. This Helium could then be sold predominantly into the European market and was shipped in cryogenic ISO containers. This was the first example of Helium being produced at an LNG plant. The GL3Z facility, built later, also has the potential to be integrated into the existing Helium facility.

5.1.4 Market Flexibility

As the LNG volumes produced at the Arzew complex have increased, changes have also been made to how LNG is stored and shipped from the facilities.

The first LNG shipment from the GL4Z complex was to Canvey Island in the U.K. on board the LNG carrier *Methane Princess*. The carrier had a capacity of around 27,500 m³. Additional LNG carriers involved in the first LNG shipments included its sister ship the *Methane Progress* and the *Jules Verne*, which had a slightly smaller capacity of 25,000 m³.

Since these initial shipments, the volumes in which LNG is traded has significantly increased. The fleet of the HYPROC Shipping Company, which serves the Arzew terminals, consists of two vessels with a capacity of 75,000 m³ (joint venture), 4 vessels with a capacity of around 125,000 m³, and a vessel of 145,000 m³ (joint venture). In addition to these, in 2017 HYPROC have taken delivery of two new 171,800 m³ vessels, the *Tessala* and *Ougarta*.

The initial GL4Z terminal, used 38,000 m³ in-ground tank storage plus three 11,000 m³ tanks of conventional design. The in-ground tank was taken out of service in July 2004 after ongoing concerns about its performance. The GL1Z and GL2Z plants both have three 100,000 m³ LNG storage tanks. The newly built GL3Z plant has two 160,000 m³ LNG storage tanks. This segregated storage between the different LNG facilities allows Sonatrach to market different grades of LNG.

This growth in both LNG storage and LNG jetty facilities at the Arzew complex over the past 50 years mirrors the transformation in the global LNG industry.

5.1.5 Decommissioning

In 2010, after almost 50 years of production Sonatrach decided to cease production from the GL4Z terminal. Over the years, several projects were undertaken to rejuvenate and increase production at the facility. However, with an aging facility, increasing maintenance costs made decommissioning a more economically attractive option.



After the decommissioning of the CAMEL plant, the history of the facility has not been lost and an exhibition at the CAMEL site now captures the birth of the LNG industry and the associated history.

5.2 Floating Facilities and Logistics

The archetypal flexibilities of a floating facility are conversion from an LNG carrier and redeployment. These archetypes are applicable to both floating regasification and liquefaction terminals.

A prime example of the flexibility brought by floating facilities can be seen in the Energy Bridge concept developed by Excelerate Energy.

5.2.1 Excelerate Energy – Energy Bridge

Founded in 2003, Excelerate Energy have developed the concept of the Energy Bridge solution, first proposed by the El Paso group in 2000. This concept utilizes the inherent flexibility of FSRUs to bring LNG to markets where it is most valuable with minimum investment costs and a short schedule for initial construction.

The Energy Bridge concept uses a purpose-built FSRU, known as an Energy Bridge Regasification Vessel (EBRV) to ship LNG to a destination. The EBRV then regasifies this cargo to the grid as required. If the energy needs of the customer have been satisfied and natural gas demand has decreased the EBRV can then depart to another customer, collecting a new cargo of LNG en-route. Alternatively, if there is still market demand for LNG, a second LNG carrier can come alongside the EBRV and provide a new cargo of LNG through Ship-to-Ship transfer.

The first EBRV, *Excelsior*, was delivered in 2005. Since, then Excelerate have developed a fleet of FSRU/EBRVs to serve a variety of projects worldwide. These range from the 138,000 m³ *Excelsior* class (4 vessels) to the 150,900 m³ *Explorer* class (5 vessels) and the most recent addition, the 173,400 m³ *Experience* class (1 vessel).

Excelerate has developed a series of 'Gateways' or 'GasPorts' where LNG is provided to markets. The first of these was the Gulf Gateway in the Gulf of Mexico.

5.2.2 Gulf Gateway - Gulf of Mexico

The first Energy Bridge project was the Gulf Gateway, which started up in March 2005. This Gateway was the world's first deep water LNG port, located 116 miles off the Louisiana Coast. The Gateway consisted of a submerged turret loading (STL) system which would be retrieved by the crew of the EBRV on arrival and, when connected, served as the offloading mechanism and the mooring platform.

The STL buoy was connected to a flexible high-pressure gas riser and then to a subsea gas distribution pipeline to bring gas to the Tennessee gas network.⁶ The project had a design sendout rate of 500 MMSCFD.



Figure 25: The EBRV *Excelsior* on station at the Gulf Gateway deep-water port

Whilst the project was a technical success and provided a quick low-cost solution to bring LNG to the American market, the facility was closed in 2011. This was primarily down to the transformation in the U.S. shale gas market, which saw a rapid decline in the volumes of LNG imported and the reversal in the direction of LNG flow, as previously discussed.

The flexibility associated with the EBRV concept was also apparent after the project was stopped. Not only was the EBRV able to continue to the next regasification project, the STL components of the Gulf Gateway were also recovered for use in other projects.

⁶ <https://www.offshore-mag.com/articles/print/volume-65/issue-6/pipeline-transportation/energy-bridge-delivers-lng-to-gom.html>

5.2.3 Teesside GasPort, Middlesbrough, United Kingdom

The second Energy Bridge Project was the Teesside GasPort Project was commissioned in 2007 near Middlesbrough, U.K. The project delivered natural gas to the U.K.'s national gas distribution system and provided access to the National Balancing Point Market (NBP).

Due to the flexibility offered by a floating solution, the project was able to move from site selection to start-up in 12 months. Further the project costs were relatively low, with the operator claiming the cost to be around 10% of those associated with a land-based terminal.⁷

After commissioning in 2007, the terminal was used intermittently to meet the U.K.'s gas needs until 2015, when it was decommissioned due to under-utilization. Again, due to the flexibility of the floating facility, the ERBV could be redeployed to a new project.

In the case of the Teesside GasPort, the benefits brought by flexibility can be extended to future projects. In 2017, plans were realized to reintroduce the regasification facilities at Teesside. With a changing energy mix in the U.K., the phasing out of coal power plants has given rise to increased forecast gas demand in the U.K. Therefore, Trafigura has taken a new lease at Teesside with the aim of introducing a new FSRU to the port in 2018. Whilst the choice of FSRU for the project has not yet been announced, utilization of the existing pipeline and jetty infrastructure will help to accelerate the project and minimize costs. This reopening of the regasification facility at Teesside is a prime example of the sort of flexibility which an FSRU offers to terminal operators.

As well as the two cases outlined above, the Energy Bridge solution is deployed at many other projects including the Northeast Gateway Deepwater Port (U.S.) and Bahia Blanca GasPort (Argentina). The concept was further used as a temporary solution at the Min Al-Ahmadi GasPort (Kuwait) whilst the country developed its own gas reserves.

⁷ <http://excelerateenergy.com/fsru/>

5.3 LNG Import Terminals

The Cartagena LNG Regasification terminal is owned by Enagás. It is located in the south east of Spain. Since operations began in 1989, the terminal has been expanded and many new functionalities have been incorporated. Presently, the terminal has a storage capacity of almost 600,000 m³ and a send out capacity of 1,350,000 Nm³/h.



Figure 26: The Cartagena LNG Import Terminal in southern Spain has added several additional functionalities to adapt to changing market conditions. Photo courtesy of Enagas

5.3.1 Breakbulk of LNG

Several functionalities have been added to the Cartagena terminal to facilitate the distribution of LNG to new markets.

5.3.1.1 Bunkering

During 2016, the small jetty has been adapted to provide bunkering services. The first pipe-to-ship bunkering operation (i.e. supplying a ship with LNG fuel directly from a regasification plant) took place in April 2017 with the Damia Desgagnes. This operation was accomplished within the framework of the CORE LNGas Hive project, which is co-funded by the European Commission, coordinated by Enagás and spearheaded by the Spanish Ports Authority. This initiative is turning Spain into the leader in LNG bunkering in Europe, a transformation which is also aided by the country's privileged geographical location as the gateway to the Mediterranean and Atlantic basins.



Figure 27: Bunkering facilities at Cartagena. Photo courtesy of Enagas.

5.3.1.2 Truck loading

The terminal has three truck bays so it can supply more than 9,000 trucks a year with LNG. When the plant was first built in 1989, it had one bay. The other two were added at a later stage.

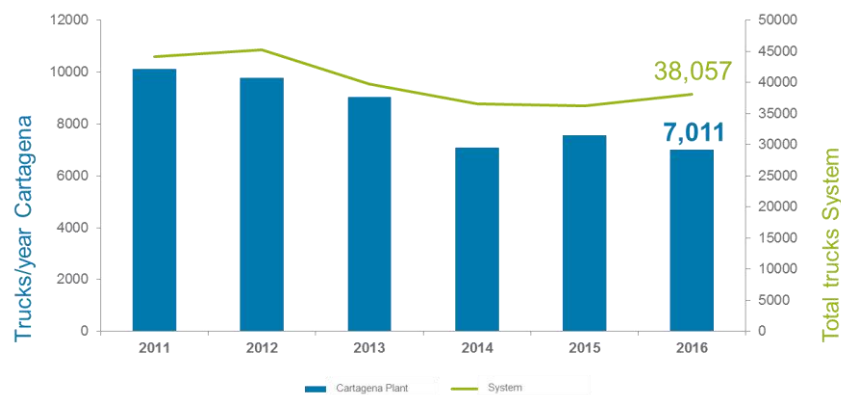


Figure 28: Cartagena's role in the truck loading evolution as part of the wider network in Spain.

Spain has more than 900 satellite regasification units to supply towns and industries where there is no pipeline. Enagás regasification terminals have loaded around 500,000 trucks in the company's history.

Cartagena's truck loading system has been adapted over time incorporating the latest technology and information. In 2016, it was adapted to load ISO container and multimodal transportation.



Figure 29: Truck loading operations taking place at Cartagena. Photo courtesy of Enagas

5.3.2 Shipping Services

5.3.2.1 Gassing up and Cool down

The terminal is equipped to offer gassing up and cool down services, operations which have been carried out several times in recent years. For gassing up, the gas in the vessel is mixed with the BOG so it is important to monitor the calorific value of the mixture to guarantee that it is inside the system limits.

5.3.2.2 Reloading

The terminal has been modified to reload vessels at 7,222 m³/h. The three liquid loading arms have been adapted so there is always a backup where needed.

5.3.2.3 Transshipment

The Cartagena terminal has two jetties and allows transshipment between two carriers at a rate of up to 4,000 m³/h. The small jetty vessel limitation is 70,000 m³.

All the functionalities associated with gassing up and reloading are also used during transshipment, including backups and BOG management. The terminal's infrastructure has been enhanced to recover all the extra boil-off gas produced through these operations.

All these improvements have driven down the total cost of tanker loading at the Cartagena terminal, placing the terminal at the forefront of loading operations in Europe.



Figure 30: Reloading at the Cartagena Terminal. Photo courtesy of Enagas.

5.3.2.4 Increasing Spot Market Trading

In 2003, Cartagena's biggest jetty was adapted to receive Qmax and Qflex. Later, smaller adjustments were carried out to enable cargo reception during the night. Storage capacity was increased from 55,000m³ to 600,000m³ in 2003 to absorb an increase in demand.

5.3.3 Improved Efficiency

5.3.3.1 Minimum Send Out

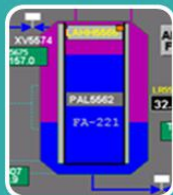
In recent years, the terminal has suffered, as many others, a continuous reduction in send out. Several changes have been made to adapt to this situation in the most efficient way.

To tackle the main concern, namely BOG management, a number of actions have been taken in three main areas:



BOG GENERATION MINIMIZATION

Warm-up parts of the terminal
Pipe insulation improvement
Tanks pressure control



BOG RECOVERY INCREASE

Recondenser On-line process simulator
BOG/seawater heat exchanger
BOG send-out to local network
Zero send-out emission compressors



BOG VALORIZATION

Energy valorization: Electricity Generators
SCV use.
Flare purge gas replaced with Nitrogen

Figure 31: Boil Off Gas management optimization in Enagas

As a result, the minimum send out rate has drastically been reduced to zero as can be seen in the figure below.

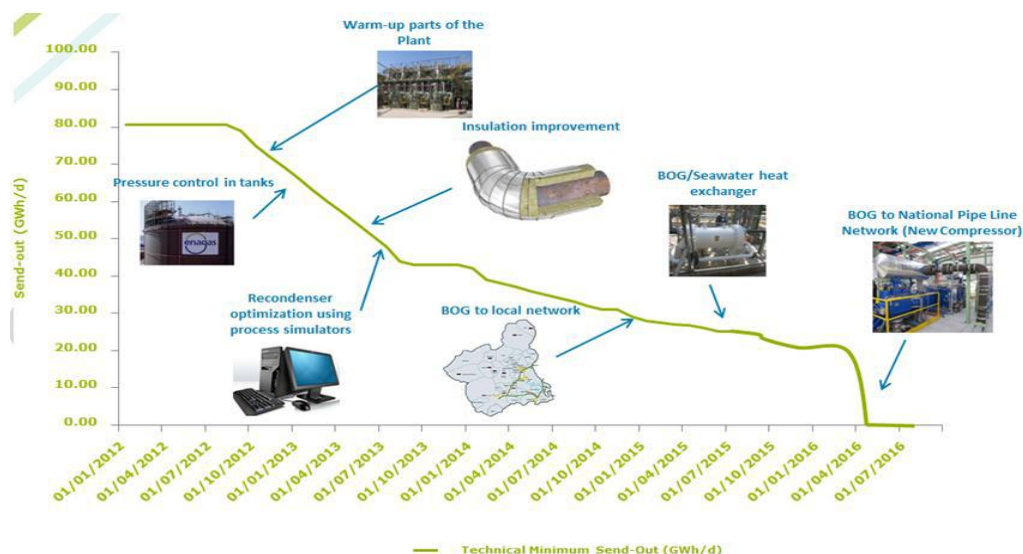


Figure 32: Key implementation steps in the Cartagena Boil Off Gas management plan

In addition, equipment has been adjusted to operate in conditions very different from the original design specifications. This has included the installation of variable speed drivers and the modification of internal components of pumps.

The decrease in BOG and the installation of network delivery compressors ensures that gas is fully recovered. As a result, tanker loading operations are shrinkage free, a result which is in line with Enagás's commercial offering to its customer for tanker loading operations at any terminal.

5.3.3.2 Energy Integration

In early 2000, the terminal was adapted to supply cold sea water to a CCGT that had been built close to the terminal at that time. This led to a significant reduction in CAPEX and OPEX, simultaneously increasing the efficiency of the vapor thermodynamic cycle.

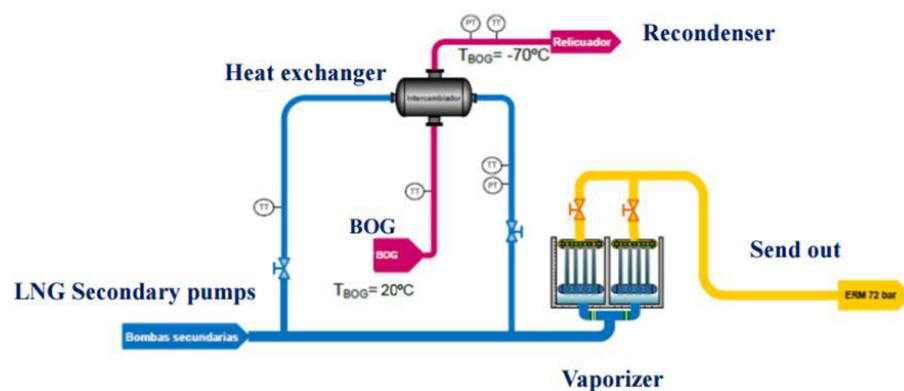


Figure 33: Cartagena BOG/LNG heat exchanger.

5.4 Import to Export Projects

General considerations and drivers are discussed in Section 3.2.2.3, but a focus on cases can provide insights on specific influences. North America represents the principal region where these projects have been developed.

Sabine Pass LNG (Cheniere)

Sabine Pass, located on the U.S. Gulf Coast near the Louisiana-Texas border in Cameron Parish, Louisiana, currently employs four liquefaction trains, with a fifth train under construction. When complete, the terminal will have a total liquefaction capacity of 3.5 Bcf/d.



Figure 34: Sabine Pass was the first LNG conversion after the shale gas revolution in North America which reversed the flow of the LNG value chain

Production from the four trains from until October 2017 is shown, along with capacity utilization, in the figure below.⁸ The average capacity utilization of the four trains in the latest 12-month period has averaged 80%.

⁸ Zaretskaya, V. and, K. Tsai, "U.S. Liquefied Natural Gas Exports Have Increased as New Facilities Come Online," Today in Energy, U. S. Energy Information Administration, 7 December 2017.

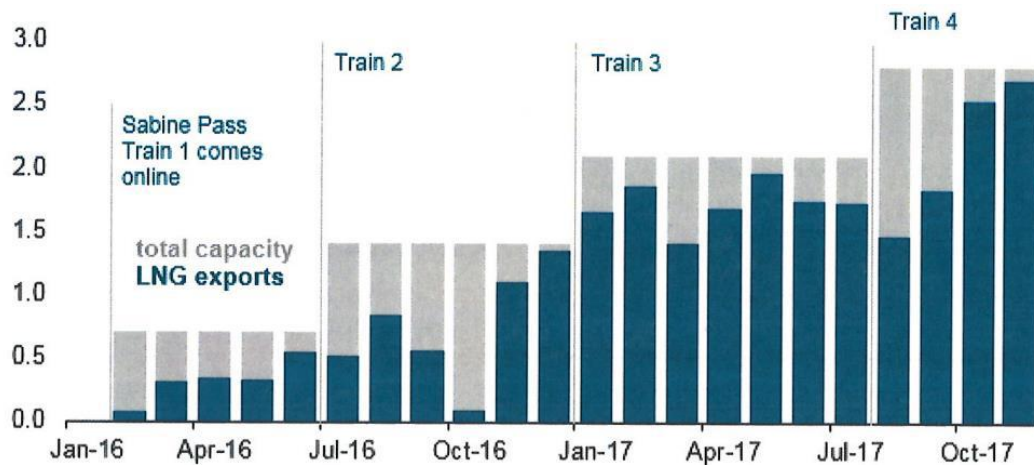


Figure 35 Forecast LNG growth from Sabine Pass LNG in bcf/d

Sabine Pass has benefitted from its central location in the U.S. pipeline industry network, as shown below. It is strategically situated for LNG export services given its large acreage; proximity to unconventional gas plays in Louisiana and Texas; interconnections with multiple interstate and intrastate pipeline systems; and marine access, with a location of less than four miles from the Gulf Coast. Since pipelines from the Gulf Coast were constructed to move natural gas out to other regions of the U.S., key pipelines have had to implement reversing flow to supply the Sabine Pass terminal.

The U.S. Federal Energy Regulatory Commission (FERC) approved the proposal for Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P. (a subsidiary of Cheniere Energy Investments, LLC) on 16 April 2012. This is the first authorization by FERC of a project to export LNG from production resources within the Lower-48 United States. Approval was initially for facilities that would enable the companies to liquefy and export up to 2.2 billion cubic feet, or 16 mtpa, of domestically produced natural gas. FERC's approval came after the U.S. Department of Energy authorized companies' plans to export LNG for a 20-year period to all Free Trade Agreement and non-Free Trade Agreement nations (DOE/FE Order No. 2833 issued on 7 September 2010).

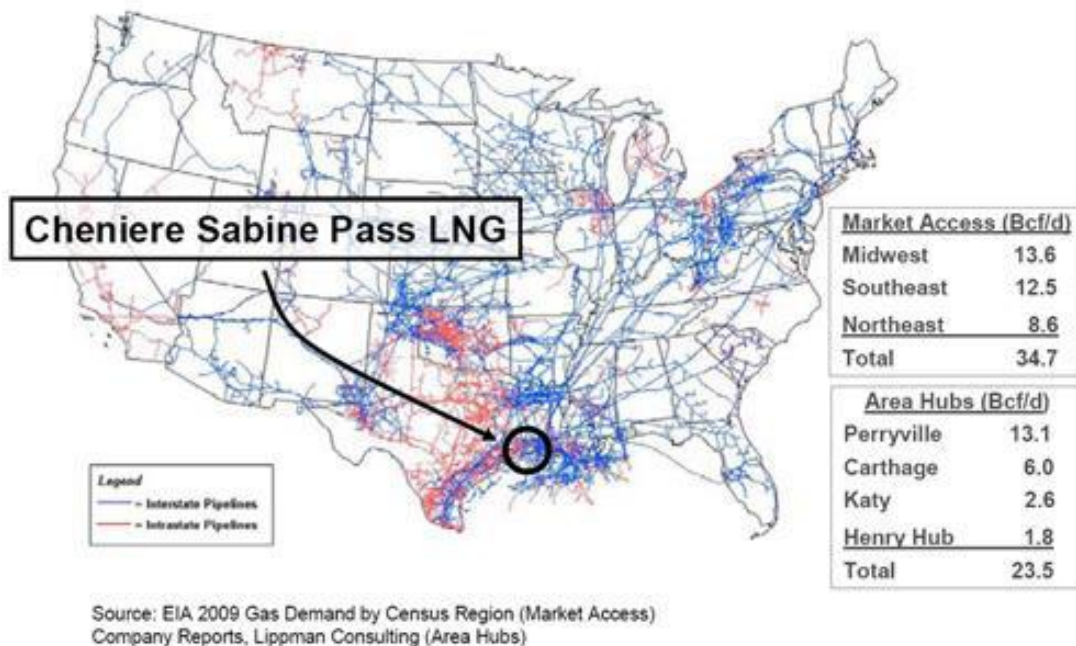


Figure 36: U.S. gas demand and pipeline infrastructure

At Sabine Pass and elsewhere in the U.S., terminals retained their authorizations to import LNG over the duration of the existing authorizations.

Each LNG process train contains gas treatment facilities, gas turbine-driven refrigerant compressors, cold boxes and heat exchangers for cooling and liquefying natural gas, waste heat recovery systems, fire and gas detection and safety systems, and other facilities. The project required the use of an additional 191 acres within the existing terminal and five existing LNG storage tanks at the site. No additional marine facilities were required for the project. Implementation of liquefaction trains - the major systems in the terminal conversion - was permitted for the Phillips Optimized Cascade Process. The project retains its vaporization send out capacity of 4.0 Bcf/d while utilizing the existing five LNG storage tanks and two LNG carrier berths.

Sabine Pass storage and jetty facilities for LNG export remained relatively unchanged from their authorized import facilities. However, major site development activities were undertaken to support liquefaction operations, dominated by the construction of liquefaction trains and

supporting facilities. The figure below illustrates the changes in the site plan, showing the location of the first four liquefaction trains prior to ground breaking for train construction.

Trains 1 through 6 are designed to produce up to 4.5 mtpa of LNG each for a nominal capacity of 27 mtpa, and process over 3.5 Bcf/d of natural gas. For the first five LNG trains, 19.75 of the 22.5 mtpa nominal production capacity (approximately 88%) has been contracted to third party, foundation customers on a long-term FOB basis under sale and purchase agreements (SPAs).



Figure 37: Sabine Pass Plan View for New Facilities, Including Trains 1 through 4 (From Sabine Pass [Final Environmental Assessment](#), 2011, Ecology and Environment, Inc., 2011)

The Cheniere business model differs from other U.S. LNG projects. In addition to processing natural gas based on the tolling model, Cheniere also procures natural gas supply for feedstock. Once the natural gas is liquefied, the customer takes delivery at the tailgate of the terminal. As a result, Cheniere is expected to become one of the largest buyers of natural gas in the U.S. once all of the trains are operational.⁹

The transition of Sabine Pass from Import Terminal to export facility is shown in the figure below, which is based on annual data up to 2017 from the U.S. Energy Information Administration. It

⁹ <http://www.cheniere.com/terminals/sabine-pass/>.

demonstrates that actual throughput for the facility is now dominated by the export function. Export data shown for 2011 and 2012 are for reloaded cargoes, not exports from liquefaction operations since liquefaction facilities had not yet been brought on line.

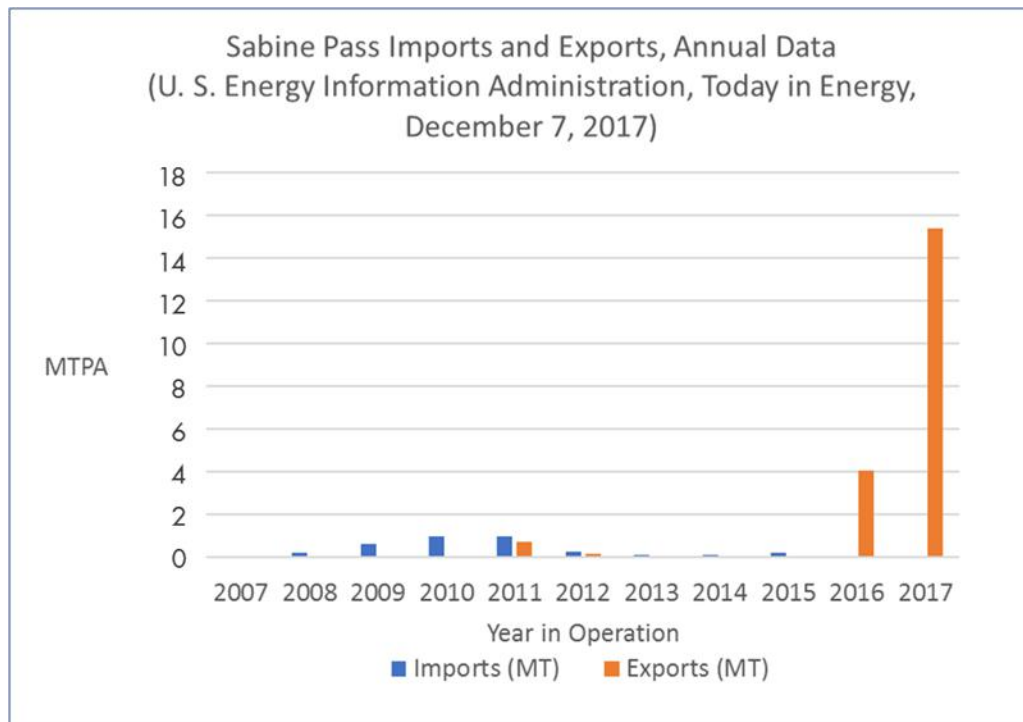


Figure 38 Sabine Pass aggregated LNG imports and exports since 2007

5.5 Peak Shaving

Examples of functional changes at peak shaving facilities (specifically noted in North American facilities) represent similar changes described earlier in this section and include truck loading and bunkering. However, the drivers and challenges for these transitions tend to be different from the examples discussed in the sections above, owing to differences in chartered facilities functions and regulatory schemes.

5.5.1 Tilbury LNG, Vancouver, British Columbia, Canada

5.5.1.1. Project Description

The Tilbury LNG project is owned by Fortis BC Energy Inc. and has been operational since 1971 as a peak shaving facility. Liquefaction capacity is currently 4.24 mmcf/d with a storage capacity of 535 mmcf. The functionality change described in this case study has been in place since 2009. The Tilbury LNG plant is a regulated, utility owned plant of Fortis BC Energy Inc. and is located in an industrial zone on Tilbury Island near the Fortis BC transmission pipeline system outside Vancouver. It was built to supplement the Lower Mainland gas supply during periods of peak demand and has an adjacent truck loading facility for emergency purposes in case of pipeline failure. This added facility has allowed it to sell LNG as a fuel on occasions, such as to a local sawmill in 1990 with spot loads under a special tariff approved by the BC Utilities Commission. Today, the plant sells LNG fuel to a broad regional market, which includes:

- Truck-based exports¹⁰ that account for close to 200 trucks;
- Remote communities in the Yukon as well as the Northwest Territories;
- Regional ferries¹¹ and roll-on, roll-off (ro-ro) vessels¹² that account for three operating LNG ships, increasing to seven by the end of 2018;
- A coalmine site in southeast B.C. owned by Teck Resources Ltd, who is piloting the use of LNG in six haul trucks;
- Local CNG stations fuelling waste haulers, buses and trucks.

¹⁰ Heavy-duty customers such as Vedder Transport Ltd., Arrow Transportation Systems Inc. and Denwill Enterprises Inc.

¹¹ BC Ferry and Seaspam

¹² Roll-on roll-off vessel for vehicle transport



Figure 39: Tilbury LNG Peakshaving Plant and Artist Rendering of Expansion, BC, Canada

Notes: Yellow Lines: Major roads. Black Lines: Railway lines

The plant is presently undergoing a \$400 million expansion to meet long-term projected growth for LNG as a fuel. The project started in 2014 and was completed in late 2017. The expansion will add 32 mmcf/d and 1000 mmcf of LNG storage. In December 2017, Fortis BC announced a first shipment of 17 tonnes of LNG to China using a ship-loaded ISO container. It is notable that the export function was not specifically part of the facility modification plan but arose out of a market opportunity to utilize facility jetty operations and liquefaction and storage operations to support small-scale export activities presented by the Chinese market.

5.5.1.2. Functionality Transition

In 2007, the BC government set forth '*The Energy Plan*', a policy to reduce atmospheric emissions. Transportation emissions accounted for 40% of BC's GHG emissions. As such, the government was supportive of any initiative to transition vehicles from diesel to LNG. It granted the rate for a 5-year pilot period starting in 2009 and permitted the utility to sell up to 1,200 LNG gallons/d.

The pilot schedule proved successful. By 2012, Fortis BC had fulfilled 54% of its monthly cap and had received so much interest for additional LNG contracts that it projected exceeding the supply cap by the end of 2013.



Ahead of the pilot programme expiration, Fortis applied for an amendment to the schedule. It sought an increase of the supply cap, the authorization to sell LNG fuel on a firm basis with a permanent tariff, and a designated tank storage capacity. The new LNG fuel supply cap required the Tilbury liquefaction facility to operate on a full-time basis. As such, Fortis BC further requested the supply source to include the Mt. Hayes liquefaction and storage facility.¹³ This additional storage capacity secured Fortis BC's ability to respond to LNG fuel demand and fulfil peak shaving requirements.

5.5.1.3. Drivers of Functional Change

Fortis BC had a growing local and regional demand for LNG fuel. In addition, the BC government's policy to reduce GHG emissions supported the adoption of LNG fuel.

5.5.1.4. Risks and Challenges

In this case the risks were limited, because:

- Storage capacity was sufficient to supply peak demand and existing local LNG fuel demand;
- Market demand for LNG fuel was growing and further supported by government subsidies;
- The LNG was priced competitively,¹⁴ which mitigated price competition from other fuel providers.

5.5.1.5. Reasons for Success

- The facility did not require investment for technology upgrades as it had a liquefaction capacity and a truck loading facility;
- Safety measures only had to reflect the change in LNG loading frequency;
- Approval from the BC Utilities Commission was facilitated because:
 - There was no additional cost burden to peak demand ratepayers;
 - There was no risk of supply disruption to peak demand ratepayers, as there was sufficient storage, in the pilot phase, to allow spot LNG fuel sales without

¹³ This facility was built on Vancouver Island in 2011. Its purpose is to supply peak demand and storage capacity but also postpone the need to reinforce the Coastal and Vancouver Island Gas Transmission systems.

¹⁴ The plant was fully depreciated. Although, the cost of fuel was slightly adjusted to reflect some capital costs in anticipation of a future plant expansion within the timeframe of the rate schedule.



affecting the peak shaving security of supply. The storage tank was never empty at the end of winter (Bennett, 2017);

- The Commission was instructed to consider all customers as ratepayers by the BC government. This meant Fortis BC could spread the cost of the additional service across all its customers.
- The plant is strategically located to service different demand markets; i.e., trucking, marine bunkering, mine sites, off-grid industry and remote communities.

6 Conclusion and Outlook on Increasing Flexibility in the Industry

By 2050, the world's population is likely to have risen to over 10 billion, and by 2060 the global demand for energy will have risen by almost 60%.¹⁵ If this increase in energy demand is to be met whilst still meeting COP 21 climate change targets then Natural Gas will have a significant role to play in the energy mix, as shown in the figure below.

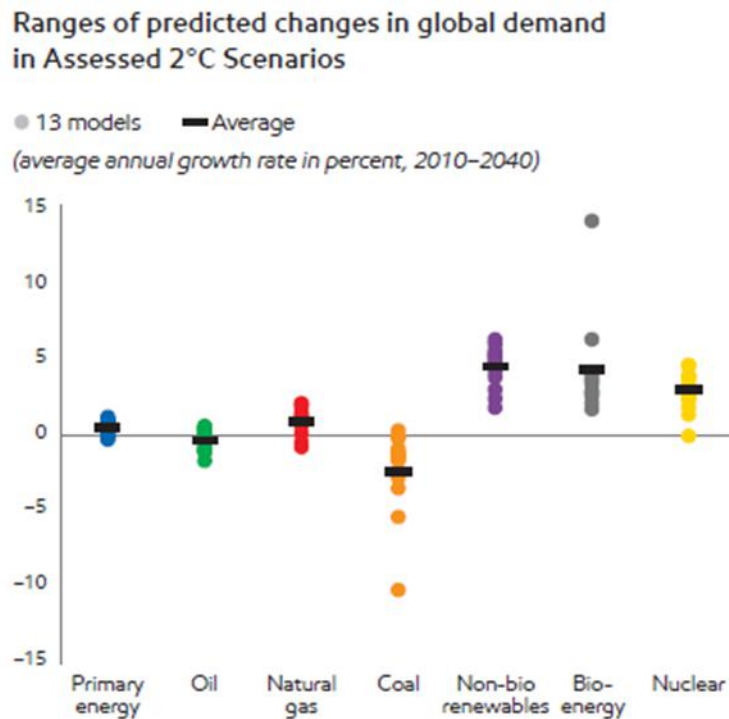


Figure 40: In an assessment of 13 models of global energy demand change to meet the 2°C Paris Agreement ambition, natural gas is expected to grow in almost scenarios. Image from Exxon's 2018 Outlook for Energy

At present, around 10% of natural gas demand is supplied as LNG. Traditionally, LNG has seen a higher growth rate than the natural gas average. This trend is expected to continue as demand for more cleaner energy grows, Figure 41 illustrates this expectation in key markets.

¹⁵ Source: UN Population Fund; UN World Population Prospects (2015 revision); World Urbanization Prospects (2014 revision); International Energy Agency, Energy Technology Perspectives 2015; Shell New Lens Scenarios.

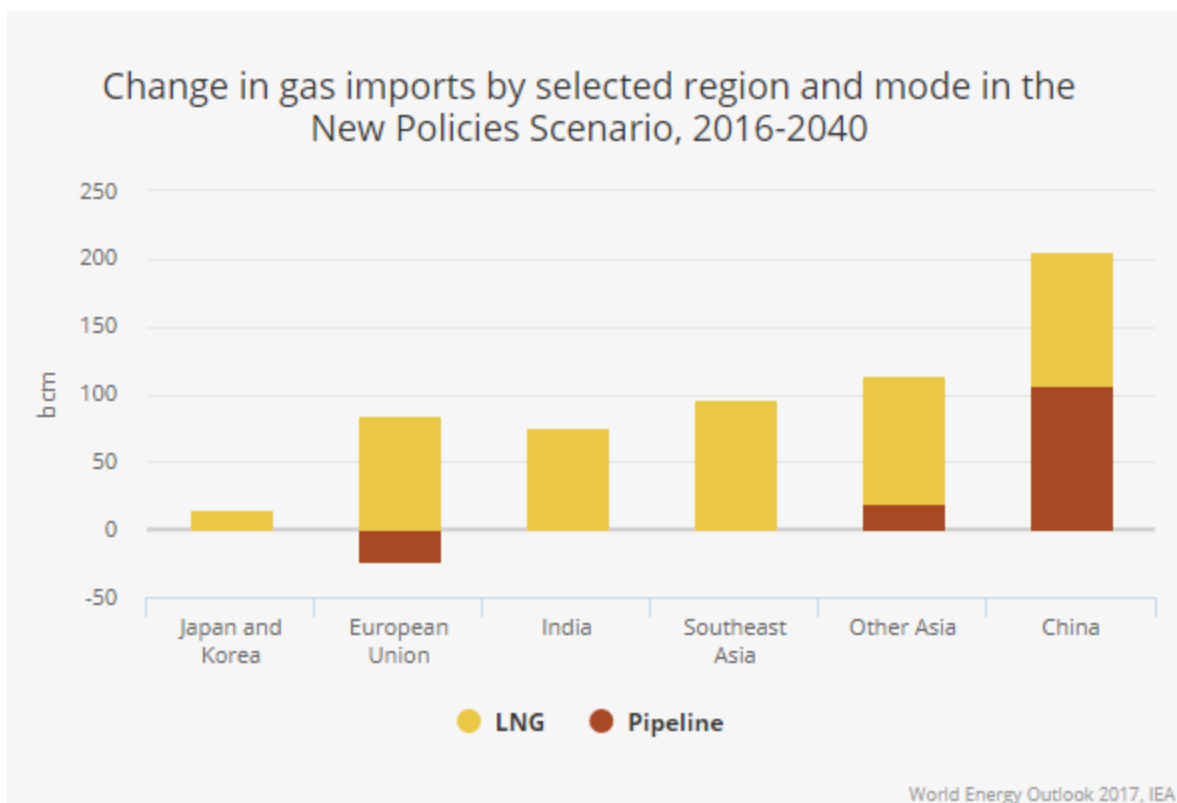


Figure 41: According to the World Energy Outlook, LNG imports will grow significantly in emerging LNG markets such as China and other Asian countries, with limited growth in the traditional LNG markets of Japan and Korea <https://www.iea.org/weo2017/>

In the coming years, LNG will not only be supplied to the traditional Natural Gas consumers such as power plants, domestic consumers and industry but will also be used in increasing volumes by the emerging haulage and shipping industries as fuel. The IMO decision in October 2016 to implement a 0.5% global Sulphur cap from 2020, rather than 2025, has spurred new orders for ships capable of running on LNG (usually as a dual-fuel option) and further studies to install LNG bunkering infrastructure at various ports.

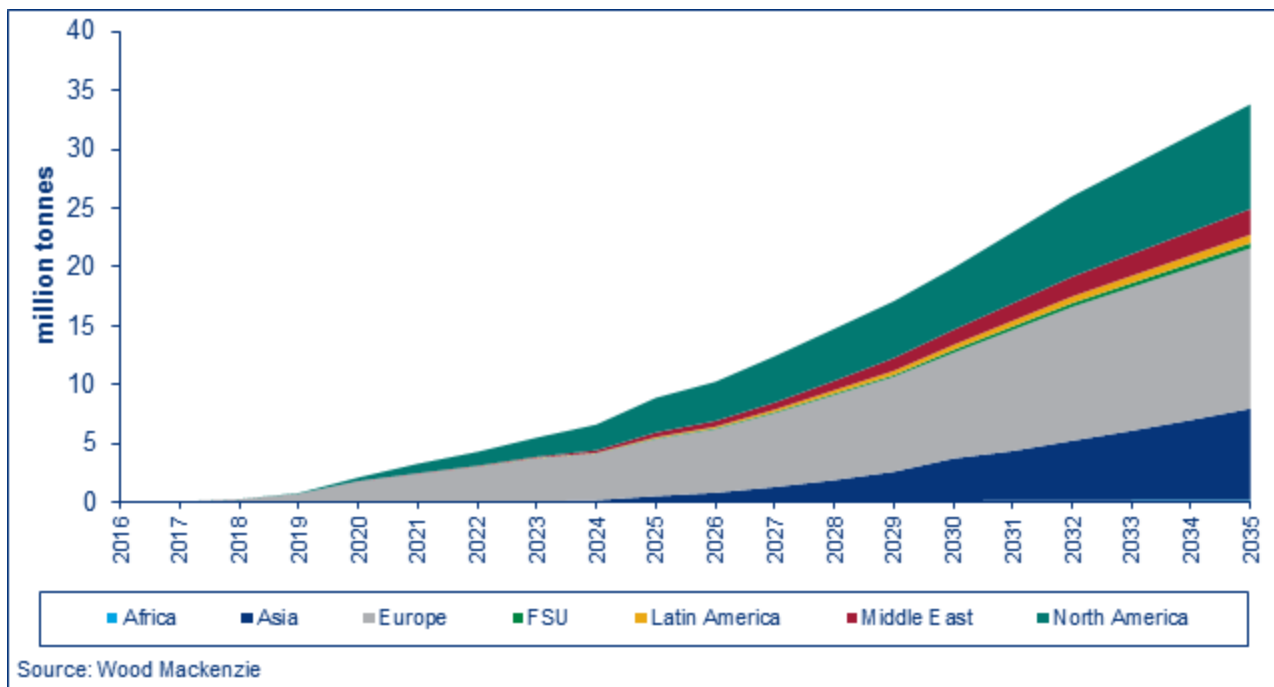


Figure 42: International LNG marine bunker demand from Wood Mackenzie's Global LNG - emerging markets overview 2017

The increase in demand in traditional markets, coupled with the growth in new LNG outlets, creates opportunities for terminals to increase utilization if they have the flexibility to adapt to these new markets. Indeed, many of the functionalities described in this report will be critical for LNG facilities across the value chain to remain competitive and profitable.

Whilst this report has focused on the addition of the new functionalities to existing terminals, there is also an increasing number of projects which have flexibility incorporated in the design phase. This is particularly apparent for LNG Import Terminals, which are often located in commercial or industrial areas where customers for LNG as a fuel may be co-located. For new terminal projects, it is important to consider early in the development phase which flexibilities can enhance the project value from market opportunities.

Many new terminals are incorporating flexibilities such as reloading and truck loading, or efficiency measures such as heat integration into the design phase of projects. These elements can either be realized during the construction of the terminal, such as heat integration in the



Gibraltar LNG Terminal and the Dunkerque LNG Terminal, both of which utilize heat from a nearby power plant to regasify the LNG. Alternatively, project developers may choose to reserve plot space and provide tie-ins so that the new flexibilities can be added with minimal impact and cost when required.

Export Facilities - Extracting Value in the Upstream

Whilst liquefaction terminals are generally located away from the markets, opportunities still exist for terminals to improve their flexibility. This can typically be done by extracting the maximum value out of the product streams. Many assets will see benefits in maximizing the value from their feed gas by extracting more valuable components and bringing the products to higher value markets. For example, as older fields may start to produce more liquids, it may become economical, or even necessary, to add or expand liquid handling/extraction facilities to monetize these liquids.

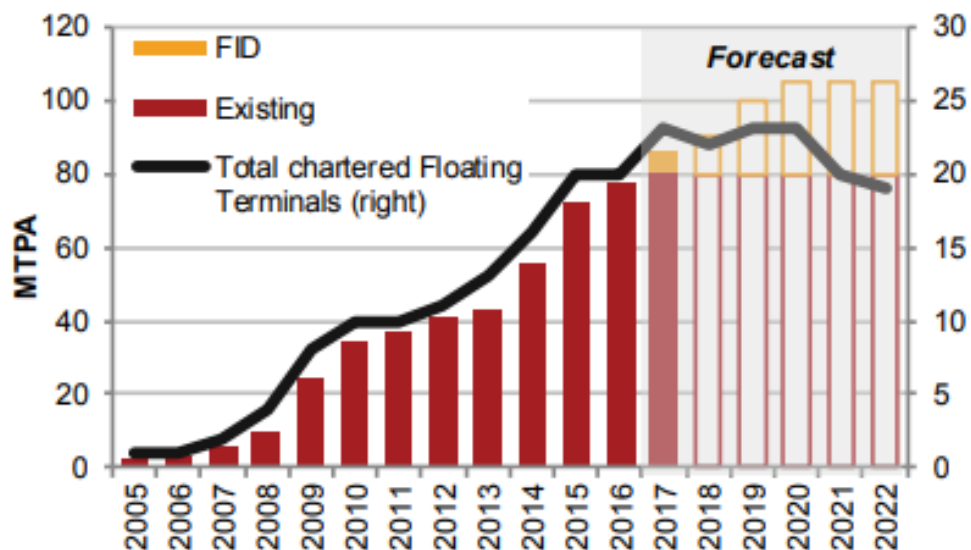
Additionally, assets may increase profitability by increasing the efficiency of the terminal and thereby maximizing the availability of feed gas to be sold as LNG product. As around 10% of feed gas is used as fuel gas, this efficiency improvement can increase the volume of LNG sold in the case of feed gas constraints. This can be done by installing new, more efficient gas turbines, both for the mechanical drive of refrigerant compressors and for power generation. Additionally, terminals may look to alternative power generation options such as gas engines or renewables.

Whilst PT Arun LNG is the only LNG export terminal to have transitioned to an import terminal to date, it is possible that other assets may follow suit, particularly since several assets have seen declining domestic gas production and rising demand.

Floating Facilities – Inherently Flexible

With the current pressure on capital expenditure in the Oil and Gas business, the number of projects utilizing floating facilities continues to rise. In 2018, proposed FLNG capacity was over 150 mtpa. In the regasification space, six of the 19 regasification projects under construction are

floating concepts. This is further driven by the rise in countries becoming LNG importers who are looking to quickly add gas to their energy mix. In many cases, this will drive countries to select floating facilities as entry solution whilst larger onshore terminals are developed as a long-term solution.



Note: The above forecast only includes floating capacity sanctioned as of end-2016. Owing to short construction timelines for FSRUs, additional projects that have not yet been sanctioned may still come online in the forecast period, as indicated by the outlined bars. The decline in number of chartered floating terminals at the end of the forecast period is the result of short FSRU contract expirations. Sources: IHS Markit, Company Announcements

Figure 43 The cost and schedule advantages of FSRUs is forecast to lead to a rise of around 35% in LNG capacity between 2017 and 2023.

LNG Import Facilities - Creating LNG Hubs

In recent years, the industry has seen a shift in the role of the LNG Import Terminal, from a simple Liquid-in Gas-out operation to an LNG Hub. In an LNG Hub, the terminal also serves as a conduit for new LNG sales to smaller satellite terminals or to high value markets such as LNG for transport. Indeed, the main function of a LNG hub terminal may be the redistribution of LNG by maritime, land and rail transport. This would result in gas send out to the network becoming a secondary function.



Conversions – Reversing the Value Chain

Since the development of tight shale gas plays in the U.S., there has been a significant reversal in the flow of LNG into the country. In 2016 the industry saw the first exports of Lower-48 LNG from Sabine Pass. With significant LNG Import Terminal capacity now being under-utilized in the U.S., many project developers have seized opportunity to convert these Import Terminals. As such conversions to LNG Export Terminals share the obvious advantages of reducing CAPEX and schedule duration compared to a greenfield LNG plant, project developers have moved to capitalize on a surplus of low priced gas. Indeed, five of the six projects under construction in 2016 in the USA were conversions of LNG Import Terminals.

Peak Shaving

Future changes to peak shaving facilities will continue to depend upon recognition of retail market opportunities to use available storage capacity but will confront various technical, regulatory, and economic barriers. In terms of technical barriers, and since peak shaving facilities are generally located in developed and sometimes urban areas, the addition of new facilities for truck loading, vehicle fuelling, and other functions may be problematic purely in terms of facility congestion and difficulties in expanding the footprint of the physical plant. Also, the addition of infrastructure such as cryogenic pipelines to navigable water ways and bunkering operations may not be compatible with adjacent land uses and land use restrictions.

In terms of regulatory barriers, the use of approved storage to serve retail functions requires creative approaches and stakeholder engagement in segmenting storage operations between the peak shaving function (paid for by customers served by that function) and the new retail use of storage. Also, the addition of new liquefaction capacity to increase facility throughput may place at risk regulatory variances for plant safety and other contemporary needs originally granted only for the peak shaving function. For example, in the U.S., additions to liquefaction capacity would threaten to remove “grandfathering” exemptions for federal siting requirements for LNG release vapour dispersion and pool fire exclusion zones. In terms of economic barriers, the need for CAPEX investment and the identification of who pays for this investment may



present difficulties since the existing customers would not likely provide the investment needed, such as through regulated rates for natural gas service.

As a consequence, the future conversion of facilities will depend greatly upon local conditions and opportunities for addressing these potential barriers. Therefore, no general statements about expansion of functionality of peak shaving facilities would be prudent. However, recent experience suggests that one or more of these barriers may be circumvented through careful development of project proposals that serve multiple stakeholder interests and early regulatory approvals of project plans. In North America, such efforts continue. Broader international consideration of peak shaving facilities has yet to develop based on research conducted for this study.

LNG in a Decarbonized Future

The energy transition will require the provision of more and cleaner energy to meet rising global demand. Meeting this demand, whilst still meeting the global climate change targets, requires a blend of energy sources. Gas is the cleanest burning fossil fuel and can therefore support an energy system which also includes nuclear and renewables.

Thanks to the high level of flexibility provided by LNG facilities (energy storage capacities, rapid ramp-down/ ramp-up of send-out rates during the day), LNG gradually becomes a balancing fuel to cope with rapid variations in the production of renewable energies (wind, solar, hydro) and ensure, through gas power plants, the stability and reliability of the electricity network.

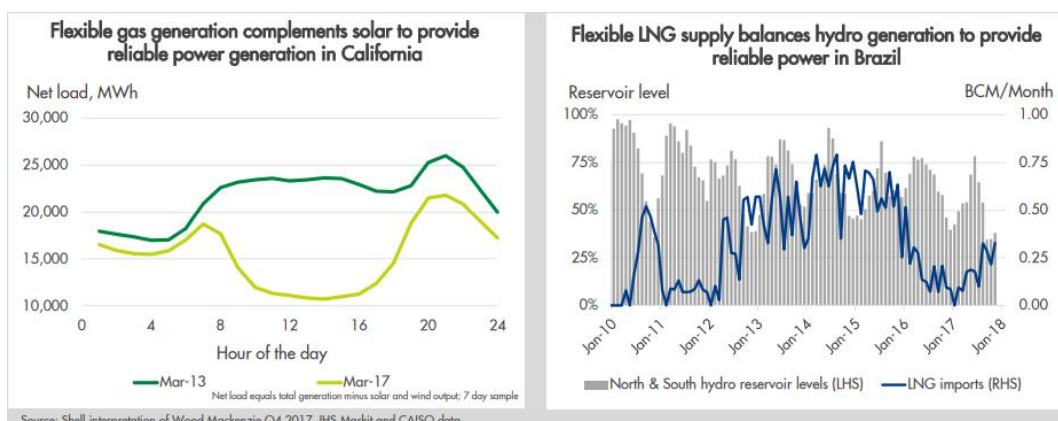


Figure 44: With the rapid increase of renewable power generation, the flexibility offered by gas turbine power generation will be key in managing the intermittent power supply.

However, only 20% of the energy currently consumed globally is used in power generation. Whilst this percentage will rise through electrification of end energy use, a substantial proportion of energy-use will not be electrified. For example, due to the high temperature needed in the manufacture of materials such as iron, steel and cement, renewables will struggle to replace oil and gas in such markets. This means gas will complement renewables by continuing to play a core role in industry and construction. Further, whilst personal transportation will likely become electric, in heavy haulage and shipping, the electrification of fleets is not practical. Therefore, the use of LNG as a fuel creates a new market for terminals, provided they have the required flexibility to supply the LNG. This may be done directly through bunkering, or by providing truck loading or reloading services to supply the LNG to third party distributors. Growth in this sector is fast moving and presents LNG terminals with the opportunity to broaden their customer-base and find a higher value outlet for LNG.

To ensure that Natural Gas contributes to meeting the COP 21 climate commitments, all the elements across the LNG value chain need to contribute to improving efficiency, reducing flaring and minimizing fugitive Methane emissions. As highlighted in this report, not only is this of great importance to reducing GHG emissions, it will also improve profitability for the asset in many cases.



New Functionalities

As society moves to a carbon-neutral energy mix, new functionalities could be envisaged. One such new functionality is associated with the increase in bio-gas production. This presents an opportunity for facilities in biogas-producing countries to become involved in the creation of a bio-LNG market. This may involve the development of bio-LNG treatment and small-scale liquefaction units or introducing bio-LNG import, storage and trading. For instance, in France, which has set the target of 10% of all gas to come from renewable sources by 2030, facilities will be needed to store and transport this gas.

In the more than 50 years of the LNG business, there have been many changes and evolutions. As industry continues to grow and develop, market demands, coupled with the rapid acceleration of the energy transition, will lead to significant opportunities for those terminals who are flexible to adapt to the new reality. Embracing the functionalities outlined in this report will be key for all elements of the LNG value chain if they are to secure their part in the growing role of LNG in the future energy landscape.

7 Appendix

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Souad	Abdallah	Sonatrach
Warin	Iamteerapaiboon	PTT LNG
Youngkyun	Kim	KOGAS
Arnaud	Planchon	Elengy
Masatada	Kobayashi	Tokyo Gas Co., Ltd.



Abbreviations & Acronyms

BOG	Boil Off Gas
CAPEX	Capital Expenditure
FEED	Front End Engineering and Design
FID	Final Investment Decision
FLNG	Floating Liquefied Natural Gas
FSRU	Floating Storage and Regasification Unit
FSU	Floating Storage Unit
HHV	Higher Heating Value
LNG	Liquefied Natural Gas
LNGC	Liquefied Natural Gas Carrier
LPG	Liquid Petroleum Gases
MRI	Magnetic Resonance Imaging
MTPA	Million Tons Per Annum
NG	Natural Gas
NGL	Natural Gas Liquids
NMR	Nuclear Magnetic Resonance
Q _{FLEX}	Qatar Flexible
Q _{MAX}	Qatar Maximum

Database of Projects

LNG facility type	Project/facility name	What? (type of functional enhancement)	When?	Why? (adjusted business models/drivers, to reduce cost/environmental footprint)
Import Terminal	Enagas Barcelona and Huelva	- Reloading of small scale carriers in actual jetty (smaller than 30,000 m3)	2016-17	Adapting to new small scale logistic services (new business)
Import Terminal		- New BOG compressors for zero sendout and unloading operations	April 2016	Actual situation of low emission, required the improvement of boil-off gas treatment facilities, to treat the boil-off gas generated in the LNG terminal during low production operational situations (even zero send-out situations) and during vessel unloading. These compressors permit natural gas self-consumption reduction, injecting the gas straight to the gas pipelines avoiding burning it in the flare.
Import Terminal	Montoir	- Cargo reloading	Since April 2012	New business, response to market demand
Import Terminal		- Cargo transshipment	Since August 2013	-New business, response to market demand such as Yamal LNG in Russia
Import Terminal		- Holding mode operations (zero sendout)	Since April 2013 during summer period only.	lack of LNG import in north of France during summer period. LNG price impact on the gas market in Europe
Import Terminal		- Jetty design and operations for larger carriers	Since 2011 for one jetty among 2. Project to design second jetty for Qmax for 2018.	New range of LNGC (Qmax)
Import Terminal		- LNG Master software use for boiloff management	Since 1990's	To predict the behavior of LNG during: - unloading of LNGC into storage tanks - holding mode (zero send-out): stratification leading to potential rollover, weathering of LNG. - transshipment between two LNGC - reloading of storage tanks into LNGC
Import Terminal		- LNG blending for gas quality	Since 1990's	to respect Sendout gas specifications (Wobbe index, HHV).
Import Terminal		- LNG Truck loading	End September 2013: first commercial truck loading	New business in France, response to market demand
Import Terminal	Fos-Cavaou	- Cargo reloading	Mid 2014	New business, response to market demand

Import Terminal		- Cargo cool down	End 2015	New business, response to market demand
Import Terminal		- Cargo transshipment	End 2015	- New business, response to market demand - give the opportunity for LNG terminals with one single berth to do transshipment (no need to perform unloading/reloading. Time and cost saving))
Import Terminal	Fos-Tonkin LNG terminal	- LNG Truck loading	End September 2014: first commercial truck loading	New business in France, response to market demand
Import Terminal		- Cold/warm energy exchange with a neighboring plant	Since plant start-up: 1972	- Electrical power consumption optimization - Reduction of environmental footprint (ORV with closed water loop)
Import Terminal		- Storage volume enhancement	2015	To cope flexibly with enlargement of natural gas demand and change of LNG procurement environment and to enhance reliability of gas supply.
Import Terminal	Osaka Senboku 1/2	- Cold utilization to reduce environmental footprint	2010	- GCC power generation - Rankine cycle power generation - BOG liquefaction system using cold energy storage
Import Terminal		- Reloading between terminals via LNG pipeline due to jetty constraints	2008	The jetty of Osaka Senboku 1 was only compatible with middle size LNG vessels (Brunei PJ). The vessels of Brunei PJ would replace to large vessel, not compatible with Senboku1
Import Terminal	Himeji	- Coastal tanker loading	2005	"IGF21 Plan", in Japan, encourages all city gas utilities to switch over to high calorie gases (mostly natural gas) by the target year of 2010.
Import Terminal		- Receiving terminal training for foreign nationals	2006	Promote exporting KOGAS technologies with basic design of LNG terminal and LNG storage
Import Terminal	Kogas, Inchon	- LPG blending for gas quality	2010	Maintain the heat value
Import Terminal		- Jetty design and operations for Q-Flex carriers	2008	For berth in Q-max series
Import Terminal	PTTLNG	- Jetty design and operations for larger carriers (125,000-264,000 m3)	Since September 2011	Volume of Natural Gas in Thai Gulf declined, response to market demand
Import Terminal	PTTLNG	- Truck Loading, capacity 500 ton/day	Since September 2011	Pilot Project to serve industry's customer
Import Terminal	Sodeshi(Shimizu)	- Cargo Reloading	2016	New Business, response to market demand
Import Terminal	Hatukaichi	- Expanding jetty and receiving facilities for standard LNG carrier	2016	-Improvement of Stability in LNG supply chain -Improvement of utilization and operating ratio -To respond to market demand in future

Import Terminal	Chita Midorihama	- Super compact BOG re-condenser	2016	-To reduce electrical cost of BOG management - Limited existing space
Import Terminal	Sabine Pass	Import to export facility conversion	First LNG cargo shipped in Q1 2016	Due to declining conventional gas production in 2000s, energy companies expected the U.S .to become large LNG importer, and therefore, many LNG terminals were built. However, with the boom in shale gas production, the Sabine Pass LNG terminal, along with others, has been greatly underutilized over the last several years: in 2013, it imported cargoes at just 0.5% of capacity and in 2014 imported only two cargoes. In 2010 export idea was proposed, originally a 4-train project but later expanded to 6 trains.
Import Terminal	Elba Island	Import to export facility conversion	Under development	As with Sabine Pass, planning for converting the terminal (in this case from a mothballed status) to exports is seen as the logical extension of use of the asset.
Import Terminal	Cove Point	Import to export facility conversion	First LNG cargo shipped in Q1 2018	After a brief reactivation of the terminal as an import terminal following two decades in mothball, sanctioning and construction of liquefaction operations to support export function were realized using dispatched shale gas from the Eastern U.S. at the feed gas source.
Import Terminal	Lake Charles (not addressed as a case study in this report)	Import to export facility conversion	Formerly known as Trunkline LNG, the project was completed as an import terminal in 1981.	Responding to U.S. supply conditions and overseas opportunities for export, the project received sanction as an export facility in 2015 for exporting just over 16 MTPA. Construction of all facility expansion and liquefaction operations are now targeted for 2019.
Import Terminal	Freeport LNG (not addressed as a case study in this report)	Import to export facility conversion	2008 completion of regas terminal, export of first LNG cargo expected in 2018	- Belief that abundance of domestic reserves and low gas prices in U.S. (because of Shale accessibility) makes exporting of gas economically attractive: a significant difference between lower US gas prices and higher international crude oil-linked gas prices is expected to remain long into the future. - LNG buyers are interested in diversifying supply and linking price to Henry Hub
Export Terminal	Sonatrach LNG plant GL3Z	-Helium and Nitrogen extraction	Pre-feed completed. FEED ongoing.	- New LNG plant GL3Z started operation in 2014 with a capacity of 4,7 Mt/a LNG. - Boil off gas from liquefaction contains 4% He and 15% N2. - Generating revenue by selling feed gas containing helium to helium plant. - GL3Z plant and other plants around it need N2 for operation and maintenance. - Helium plant (HELIOS) is in operation and is 2000 m only from GL3Z. - Tie in for connection to helium plant existing at boundary limit of GL3Z.
Export Terminal	Peru LNG	- LNG Truck loading	2017	- To provide gas to off-pipeline communities in Northern and Southern Peru

Export Terminal	Woodside, Pluto	- LNG Truck loading	Under construction 2018	- New market access to provide LNG as fuel to heavy industry nearby
	Arun LNG	Conversion from export to LNG receiving facility	Final cargo to KOGAS was sent October 2014, start-up of regas facility in early 2015.	6-train Arun LNG project started operations in 1978 and reached end of its life as export project (declining gas deliverability from upstream field, no new prospective gas reserve, expiry of LNG contract in 2014). PERTAMINA fully decommissioned Arun in 2014 at the end of the KOGAS contract. Gas production is likely to continue beyond 2014, but will be sold to the domestic market. Reasons for converting facility into regas terminal include: - To provide additional gas supply to region for rising demand and maintain the sustainability of industrial activities (unavailability of gas supply was closing other industries in area) - To revitalize the industry such as fertilizer, pulp paper and power plant. - To enhance National Energy Security and Sustainability. - To create national gas infrastructure to support the gas network long term program NOC PERTAMINA also plans to use the Arun regasification terminal as a gas hub for the region as well as LNG & LPG trading hub internationally
Floating	FLNG Hilli	LNG carrier conversion into midstream FLNG	Start-up 2018	Main driver is to provide substantial lower unit cost liquefaction for stranded assets
Floating	Golar Spirit	LNG carrier conversion to FSRU	Operating since 2009	- Main driver to convert LNG carriers to FSRUs is to provide cheaper solution compared to (new build) land based terminals (reuse of facilities). - Development of FSRUs is also considered attractive over land based terminals for supplying gas to riskier countries, where gas demand is rising. - Quicker to deploy and develop - Flexibility -> potentially FSRU can be relocated?
Peak Shaving	Tilbury (not addressed as a case study in this report)	Peak shaving expansion, truck loading, vessel bunkering, LNG export	Construction completed in 2017 with a first export of LNG in 2018 in advance of other functions.	A key project feature and factor for success was early and regular engagement with regional stakeholder to overcome potential opposition to facility expansion.
Peak Shaving	Richmond LNG	Expansion for conventional and merchant gas operations, truck loading	Merchant LNG operations begun in 2013.	Stagnant peak shaving demand and proximity to merchant gas market opportunities led to decision for expansion.

Peak Shaving	Acushnet LNG	Expansion for potential satellite operations and merchant gas operations via truck loading	Project is on hold.	Facility receives LNG via truck deliveries from the Everett, Massachusetts import terminal and lacks transmission line delivery option, having been built to serve the local distribution market. Current obstacles to project development include local opposition to expansion. Regional gas demand incentivizes expansion, but direct use for fueling operations is at best limited because of lack of transportation access to potential retail customers.
Peak Shaving	Kinetrex Energy	Truck loading	Merchant LNG operations begun in 2013.	One of two plants remaining in operation due to declining peak gas demand requirements operates as both a municipal peak shaving facility and merchant gas operation serving developing LNG vehicle fuel markets.



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