LNG Committee Study Group 2

Pathway to Liquidity for LNG in the Energy Market

PRODUCED BY:
INTERNATIONAL GAS UNION
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Executive Summary

Historically, the LNG market has been considered an illiquid market characterized by long-term contracts to protect consumers from sudden price spikes and to provide security of supply for large importers. This kind of contract also reduced uncertainty for suppliers making long-term investment decisions. However, since 2010 new LNG importers are providing diversity to the LNG market by procuring from the spot market, supporting short-term LNG trade growth, representing 28.7% of all global LNG trade in 2017.

The increase of short-term contracts and an abundance of LNG supply and shipping, has allowed new markets to develop. In addition, FSRU deployments have allowed a more diverse market to develop and with it, market conditions that are bringing additional liquidity to the LNG market.

The liquidity is a measure of the ability to buy or sell a product without causing a major change in its price and without incurring significant transaction costs, representing a large advantage for a market.

Therefore, the identification and analysis of drivers which have an influence on the liquidity is critical for the LNG industry. This report analyses seven of the main drivers, their current status and the existing barriers for each one that should be removed to increase liquidity.

1. LNG Hub Formation: Price transparency is a key requirement for expanding the liquidity of LNG. The most effective way to gain price transparency is through the mechanism of a functioning Asian LNG hub that is based on an accepted price marker. Natural gas hubs exist in key markets such as the United States and Europe. LNG hubs are currently proposed by Singapore, Japan, and China. Each of the proposed LNG hubs has hurdles that must be overcome, but are actively being supported. Progress for developing an Asian LNG hub will take time, as seen in the history of HH and NBP.

Singapore appears most advanced due to a regulatory structure that supports free trade. However, it has a small market size and almost no pipeline gas competition that would make it a nearly pure LNG market. Japan has made progress toward
deregulation of its gas and power markets by promoting unbundling and 3rd party access. Further gas interconnects are needed within Japan to allow gas to flow between demand centres and promote a true unified market. China has also begun 3rd party access and limited trading on the Shanghai Petroleum and Natural Gas Exchange (SHPGX) (including LNG). In both the case of Japan and China, a potential hindrance is the security of supply mandate of LNG import-dependent economies. To date there is no clear winner in the LNG hub race.

Another market mechanism that could evolve is the promotion of price transparency by use of a differential to an existing gas hub, e.g. Henry Hub, NBP or TTF. This is the current process for regional gas sales in liquid markets. Henry Hub derived LNG has begun to arrive in Europe and Asia. This along with LNG reloaded or diverted from Europe, which has an alternative value of NBP or TTF, is moving flexibly between markets. A trusted trading platform could further promote this concept.

Other LNG trading points, such as Spanish LNG Terminals, are not considered yet to be LNG Hubs, because transaction prices are not published. Having a transparent price for transactions proves to be one key factor to be developed.

2. **Capital Costs:** The LNG supply chain is a capital-intensive operation, involving the pre-treatment, liquefaction, storage, shipping, storage and regasification of gas. The capital costs of this supply chain have increased substantially over the past decade, thereby causing many export projects and land based import projects to be deferred or delayed. Opportunities do exist for reducing liquefaction facility costs such as shared infrastructure and site selection, technology & project execution and life extension.

While none of these represents a ‘silver bullet’ which will radically reduce costs overnight, there are reasonable expectations that some of these might work.

3. **Shipping:** The current LNG shipping market is driven by technical, logistical, commercial, regulatory, financial and cultural factors which can either constrain or reinforce its level of liquidity. When analyzing the liquidity of the shipping market, we look at the transactions which are made, the period of the same, available fleet, the amount of production that enters into the market, freight level and other relevant factors. The growth in liquidity began in 2013 as a wave of LNG carriers was delivered by the shipyards, many without term engagements, adding length to the shipping market.

4. **Receiving Terminals (including Small-Scale):** Receiving terminals have an impact on liquidity due to various factors, such as, capabilities, services offered and commercial issues. For this reason, to obtain a global, flexible and liquid market, LNG terminals have a key role and operators should constantly optimize utilization of their facilities and invest in improvements to allow large and small scale activities to coexist at the terminals. These enhancements will help create liquidity to stimulate the creation of a global market that will ensure the security of supply and a coherent LNG price.
5. **Market/Supply:** The LNG market has dramatically changed over the past half-decade. Especially, on the supply side, a surge in natural gas production in the United States has eliminated the need for imports and promoted flexible LNG exports. At the same time, new LNG projects from Australia have added significant supply to the balance. This large growth in supply and increasing flexibility is having an impact on volume of LNG in the spot market. In addition, from the perspective of the demand side, the market has balanced via growing consumption from traditional consumers. Also new countries are starting to import LNG as volume has grown and pure traders enter this space. The market has clearly increased the number of buyers and sellers. To keep the momentum towards the market liquidity, the number of participants on both sides needs to keep growing to eliminate the distorting effects of market concentration.

6. **SPA’s:** Sales purchase agreement (SPA) terms and conditions continually evolve to reflect an expansion of LNG production capacity, new technologies involved (FSRU), new import participants, changes in global LNG demand structure, portfolio sales, and deregulation of downstream markets (e.g., third-party infrastructure access and competitive pricing). Moreover, it should be taken into account that political, economic and social conditions will change over time – usually unpredictably. If the LNG market liquidity increases, the commercial structures and terms and conditions of the sale will need to be robust and balanced to moderate the likely market fluctuations and, at times, dislocations.

The removal of destination clauses in FOB contracts will be a pivotal adjustment in the contracts. This change will enhance LNG liquidity by enabling different kinds of trading activities, e.g. location/time swaps, call/put options etc. SPA terms should be adjusted in the manner to provide mutually balanced terms for sellers and buyers, thus enhancing and allowing for security and flexibility at the same time.

Finally, standardization may enhance LNG liquidity by reducing transaction costs. Standard contractual clauses should include force majeure, termination rights, governing law, dispute resolution, seller’s liability for off-specification LNG and seller’s shortfall, tax indemnification and the indemnity regime.

7. **Quality:** The harmonization of LNG quality and gas interchangeability is a key driver to facilitate tradability and liquidity as well as safety and operability for domestic, commercial and industrial applications. The prevailing view is that the world is divided into regions where different specifications predominate and this will continue, with “rich” LNG required in some and “lean” LNG required in others.

The report provides a global view of the current situation regarding LNG market liquidity and how each driver has an important influence on liquidity, but they are not enough individually, and a global improvement of all drivers is required to develop a truly liquid LNG market.
Chapter 1 – Global Price: LNG Hub Formation

1. Introduction:

Liquidity is a measure of the ability to buy or sell a product without causing a major change in its price and without incurring significant transaction costs.

There are many reasons that increased liquidity is advantageous for a market. Firstly, the product becomes more accessible to consumers. Rather than being reliant on a long-term contract, a buyer can obtain the commodity at a moment’s notice, or at least gain exposure via the paper market. For suppliers, a project sanctioning is not dependent on long-term contracts that are necessary in non-liquid markets due to the risk of stranded investment capital. A key benefit to the commodity itself is the potential for market share growth against other competing products, as pricing transparency improves. In the case of LNG, it is expected that a liquid market will lead to greater competitiveness against coal and liquid fuels, especially in power generation. Liquidity does not however eliminate the potential for price spikes or crashes. Supply-demand fundamentals, trading trends and external events, will continue to drive price.

Liquidity of LNG is being sought mainly by buyers now, with specific hub proposals in Singapore, Japan, and China. There are challenges to the development of an LNG hub, mainly due to access to infrastructure, size of market and (downstream) market conditions required, that are not all concurrently available in one place. An LNG hub would also promote LNG pricing transparency. However, it is possible that LNG pricing transparency can be achieved by use of existing liquid gas hubs. As Henry Hub (HH) and National Balancing Point/Title Transfer Facility (NBP/TTF) are fully functional gas markets with both pipeline gas and LNG supply, there is potential to price LNG anywhere in the world based on these markers.

This chapter will explore the potential role of price and sales structure to determine the evolution of liquidity for LNG.

2. Where are we now?

Currently, pipeline gas is traded at hubs both in North America (HH) and Europe (NBP &TTF). Mature hubs provide the needed structure for liquidity to be realized via active trading. The creation of an Asian LNG hub is thought to be what is required for liquidity of LNG. Hence in this section we describe the function and development of pipeline gas hubs to determine insights to the status of on-going LNG hub development efforts and the desired effect of market liquidity and price transparency. The mechanism of using an existing hub, such as TTF, to achieve the desired effect of market liquidity and price transparency will also be discussed.

2.1. Hub concept: What is it?

A hub is a physical or notional place where gas is traded. It provides a platform where buyers and sellers can agree to transact on physical and future delivery of natural gas. This becomes an effective mechanism for price (value) determination of natural gas because many consumers, producers and speculators are ready to transact. To qualify as a hub, several factors can be considered. Churn rate, or ratio of traded volume to
physical volume, is one factor that can be considered in determining comfort that the resultant price is a market-wide accepted outcome. Other considerations are the number of buyers and sellers, and the activity of non-physical traders.

A hub must have clear rules on credit-worthiness of participants and on settlement obligations. If a buyer is holding a contract at expiration, they must be capable of clearing physical delivery at the stated point. Likewise, a seller must be able to physically deliver if they hold a contract to expiration. In reality, most contracts are settled to cash prior to expiration, eliminating the extra cost of physical handling. As such the “risk” of bringing a contract to maturity is more important to traders and the trader’s ability to “get out of a market” a key measure of confidence.

Although most gas may not be sold physically at the hub, the trading process provides confidence in the market of the clearing price determined. This price becomes the basis for many physical bi-lateral transactions that never enter the “hub”.

2.2. History: How have hubs developed in US?

The Henry Hub is the most active gas trading point in the United States, and the world. It is both a physical and paper trading hub. It was established as a physical trading point in the 1950’s, with several pipeline interconnections. But it wasn’t until 1992, after deregulation and unbundling of the natural gas industry, that full-fledged trading began. With strong market rules, interested players, abundant supply and demand; the Henry Hub has become one of the most perfect markets in the world. Other trading points in the United States are referenced by a differential to Henry Hub in setting their prices. Gas flows largely unencumbered between supply point and demand locations based on optimized least cost. The greatest challenge for Henry Hub in the future is the relocation of the centre of gravity of production from the U.S. Gulf Coast to the Marcellus (Pennsylvania) region with the advent of shale gas. There is no technical reason that Henry Hub cannot continue to function, especially given the momentum of paper trading at that location. However, it is plausible that a shift can occur given the continuing shifts in production geography.
2.3. How have hubs developed in EU?

NBP became the first European hub, and also a model (benchmark) for other hubs in Europe. The creation of the NBP was a result of the liberalization of the UK gas market. The effective start of hub trading was the development of the Network Code in 1996. Network Code established procedures and rules for third party access to British network, introduced daily balancing protocols and the National Balancing Point (NBP) - a balancing platform, where shippers nominate and where the system is balanced on a daily basis by the system operator. NBP soon evolved as a trading point, becoming the most liquid hub in the UK, so market players had assurance in trading there. Moreover, NBP has soon become a reference for wholesale gas trading and was used as the basis for the standardized contract NBP’97 - a foundation of the British OTC traded market, and the ICE gas futures market. Since this time, the number of participants and trading volumes increased rapidly. New methods of trading such as futures, swaps and options supplemented more traditional OTC deals. NBP has been considered a ‘mature’ market for more than 15 years now. It remained the most active traded hub until recently, but has lost its position in 2016 as the Dutch TTF has exceeded it by all liquidity indicators.
2.4. Is an LNG hub the only way to deliver liquidity?

A fundamental question that must be answered is whether an LNG hub is the only way to promote liquidity of LNG. LNG is not an independent product; it is a subset of the natural gas complex. In the oil market, we do not have one hub for pipeline oil and one for waterborne oil. Just as those two marketed volumes rely upon the same indices, Brent and WTI; LNG and pipeline gas can share price indices and insure their connectedness. By the definition of a hub, liquidity is a given. However, can the liquidity of an existing gas hub be transferred to the LNG market via a similar market mechanism as basis differentials used in pipeline markets? Given the uncertainty of an LNG hub developing, this is a fair concept to explore.

3. Benefits of liquidity to market players

Henry Hub sourced LNG has begun to arrive in Europe and Asia. This along with LNG reloaded or diverted from Europe, which has an alternative value of NBP or TTF, is moving flexibly between markets. These deliveries and trades will promote price transparency. Price transparency promotes liquidity by making bid/ask offers closer in absolute terms. To a large extent, this market mechanism is underway, with no

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<th>2016</th>
<th>5 KEY ELEMENTS</th>
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<td>Active Market Participants</td>
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<td>TTF</td>
<td>&gt;40</td>
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<td>NCG</td>
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<td>GPL</td>
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* Score is derived from the OTC and Exchange product categories in the Traded Products Table.
** Score based on each of the Key Elements scoring zero for Grey; 1 point for Red; 2 points for Amber; 3 points for Green.

regulatory or government incentive. It is a natural approach that may develop faster than promulgated hubs.

2.1. More pricing options/arbitrage: a necessity for suppliers

Suppliers are making direct sales of LNG to end-users, in the form of long-term sales contracts valued against a percentage of crude oil prices; and more recently under shorter-term contracts or even spot sales achieved through tendering processes. These can use “fixed price”, oil indexation or natural gas indexes like Henry Hub (HH), NBP in the UK or TTF in North-West Europe, plus sometimes spot LNG indexes published by agencies such as Platt’s, Argus, ICIS, etc.

From a supplier’s point of view, there has always been a need for selling extra cargoes on top of long-term commitments. For operational flexibility, projects tend to contract at levels below nameplate capacity. In addition, actual production capacity can be higher than nameplate. There are also timing uncertainties of first LNG that can require managing early cargos or bridging volumes to meet contractual obligations.

Therefore, suppliers have developed teams of “portfolio” managers to handle the need for complementary sales on top of long-term contracts. On the shipping side, suppliers manage their fleets of LNG carriers to run the operation as smoothly as possible. Again, the more options available, the more value that can be created for both suppliers and customers.

3.1. Demand security- what’s the trend in contracting long-term LNG?

Since 2014, when oil price collapsed from $100/bbl to below $50/bbl, fewer long-term contracts have been signed with smaller quantities by contract; leaving a greater avenue for short-term and “spot” sales.

Short-term price indexation has trended to either 100% HH, 100% crude oil (JCC or Brent) or a mix of both; assuming a 50/50 balance between HH and JCC in mixed formulae, it appears that oil indexation represented 64% of the quantities with China leading the pack with a 91% ratio, followed by Japan (54%), Korea (56%), Taiwan (18%) and Singapore (24%).

From January 2017, with a lower oil price outlook and the start-up of new projects in Australia that make use of oil-indexed contracts, the use of hub indexing has slowed down. European buyers continue to use Hub natural gas indexes, to be in line with the common practise of the EU market.

3.2. Transparency benefits

Buyers and sellers take comfort from knowing that they are transacting in a competitive price range. Due to contract confidentiality, the only available information on quantities and prices historically, has been the official monthly government statistics, the GIIGNL publications and various trade reporting agencies.

With the development of tendering processes (initiated by Suppliers or by Buyers) for spot transactions came the need for more visibility and transparency. Each party of a
tender should have a clear understanding of what to expect in terms of price/location/volume before striking a deal.

3.3. Traders: Physical & Financial

Current LNG market activity blurs the line between the aggregator and the trader. As a simple definition though, a trader tends to take shorter and smaller positions compared to an aggregator. Traders tend to have smaller balance sheets than larger International Oil Companies (IOCs, which make up most of the large aggregators) which limit the contract length they can commit to. Moreover, taking on longer positions might impact their ability to exploit short-term disconnects in the market. However, this does not preclude them from signing long-term deals altogether. Nevertheless, while a trader might be predominantly focused on deals over the near-term months, an aggregator would be generally focused on multi-year positions.

2.1.1. Traders

Pure traders act as a middleman between producers and end users. This role offers players opportunities to fill in the gaps and also to arbitrage differentials in (price, location and volume) between various LNG markets while providing credit and shouldering risk for both sides of the transaction.

Supply availability in the LNG market has allowed commodity traders without access to their own production or long-term supply, to enter short-term trade opportunities. LNG trade is still dominated by the traditional long-term contract structure between producers and end-users; however, similar to LNG aggregators (see next section for definition), commodity traders act as a go-between for producers and end users, investing in logistics and storage to facilitate trade, while providing credit and risk diversification for both sides of the transaction.

Typically, these types of traders have provided liquidity in spot commodity markets:

- New buyers with low credit ratings and high country risk enables commodity traders to act as an intermediary for traditional suppliers.
- Traders are closer to emerging markets because of established oil trading positions and in some cases coal and mining positions. This gives traders a thorough understanding of the regulatory challenges and port specific operations.
- Commodity traders are open to creative pricing structures as they can meld physical trading with their expertise in financial hedging.
- Traders are able to accommodate buyers’ request for variable delivery schedules as they are not tied to a single project.
- LNG supply growth over the next 5 years provides liquidity for traders to build a diverse portfolio to suit buyer requirements.
- Traders offer necessary flexibility at the margins
- Commodity traders are stepping up their activity in LNG, adding liquidity and carving out a niche in a market dominated by traditional LNG producers as new supplies and markets create fresh trade opportunities.
In the coming years, the market may be more saturated with uncommitted, flexible volumes, opening the opportunity for traders on short-term LNG trade. Many of the US offtakers – and Australian producers for that matter – expected Asia to be a safe bet for uncommitted LNG supply, but regional demand uncertainty may shift some of these volumes to the spot market, offering expanded potential supply for traders.

The near-term market remains ripe with opportunity for traders: In emerging markets, buying tenders gave a much-needed outlet for LNG that was unable to be absorbed in the initial target regions. New importers entered the LNG market at a time of oversupply that allowed them to quickly move forward with less expensive FSRU agreements without supply contracts in place, a perfect target market for a commodity trader. The most notable is Egypt where rapid production declines and domestic demand growth gave the supply-constrained market incentive to find new gas supply sources. As more of these new importers come online in the age of oversupply, commodity traders will be able to provide credit while acting as the middleman between risk-averse sellers and high-credit risk consumers.

These commodity traders are becoming more involved in LNG given recent favourable market conditions for their business model. Typically, these types of traders have provided liquidity in spot commodity markets, with companies establishing significant positions in LNG, particularly in respect to emerging markets. Moreover, with a cargo costing $7/MMBtu in 2015, compared to a high of $18/MMBtu only a year before, the capital risk for cargoes has softened, allowing these niche players to emerge and capitalize on perfecting the logistics needed in flexible trading. Despite the reduced capital required to back an LNG trade, the flexible nature of commodity traders comes with considerable financial risk with high exposure to price volatility. With additional liquidity in the LNG space, the role of the pure trader will contribute to how the market evolves over the next five years of oversupply.

### 3.3.2. LNG aggregators

Historically, an aggregator was a company that aggregated one part of the supply chain, combining small parcels of supply or demand into larger volumes and then buying or selling gas in those larger units. For example, in the 1980s, British utility British Gas amalgamated gas supply from the North Sea for sale into the UK market. At the other end of the chain, utilities aggregated the needs of smaller Japanese consumers and secured LNG offtake contracts to meet that demand. As companies sought to grow their LNG businesses they took positions at one or both ends of the LNG value chain, aggregating demand and/or supply over different periods.

LNG aggregators have been a key driver of growth in the LNG business over the past ten years, and their role has matured from cargo intermediaries, to companies underpinning the growth of new LNG capacity. The role of LNG aggregators has evolved since BG Group started its trading and optimization activities in the mid-2000s, whereby it secured short, medium and long-term LNG supply and sold LNG on varying contract lengths to buyers, using its fleet of chartered vessels. Through optimizing LNG flows and due to its flexible portfolio allowing it to respond to sudden market changes after the Fukushima incident in 2011, the company helped to rebalance the market.
Other companies have since joined the business though some of which operate on a shorter-term basis, blurring the role between a “trader” and an “aggregator.”

The rapid development of US LNG export projects from 2011 onwards was considerably underpinned by aggregators. Moreover, the flexible destination rights of US cargoes will make traditional consumers of LNG a new sort of aggregator in that they can sell volumes as needed. In many cases, both traditional and non-traditional aggregators still have unsold volumes over the next several years during which time the market is expected to be oversupplied.

The large aggregators have underpinned the development of US LNG. Although US LNG’s contract flexibility would be attractive to traders, the reasons stated above likely precluded them from being offtakers. However, some Asian LNG buyers have sought to optimize their US portfolios through swap deals with traders.

In an increasingly liquid market for LNG, companies cannot just “sit in the middle” between buyers and sellers and collect a margin. Intermediaries need to add value to justify a trading premium. Traders therefore must take a position in the chain and use that position to trade around. In most cases, traders would manage price risk through back-to-back pricing formulae, hedge positions using oil or gas futures, or swaps in the over-the-counter market.

In recent years, the length of contract period that aggregators and traders operate in has evolved. Aggregators have tended to incorporate more shorter-term deals into their portfolios and in a few instances traders have taken some longer-term positions.

A host of factors including the onset of greater volumes of destination-free, hub-priced LNG from the US, greater volume and price flexibility from other LNG supply sources, and unexpected demand changes has blurred the definitions of players. In many cases, large LNG buyers have entered contractual arrangements with European companies to swap or sell LNG cargoes in order to manage their volume and price exposures. In optimizing their overall LNG portfolio, these buyers are taking on an aggregator role.

As the industry enters a period of oversupply giving buyers greater choice, trading margins are under pressure. This has already happened and explains why companies such as ship owners and financial institutions have largely exited the LNG trading business. However, we expect that the aggregator role will continue to be critical for the market’s trade flows during the period of surplus.

4. Progress on Asian LNG hubs and trade

There are advances by several countries in pursuit of a hub, with most advanced concepts in Singapore, Japan, and China.

Singapore has an advanced financial and trading centre which has been successful in adding liquidity to many other commodities, including oil. Natural gas has been imported via pipeline from Indonesia and Malaysia. Since 2013 LNG has also been imported from numerous supply countries. In addition, over half of the world’s LNG
trade travels via the Malacca Straits near Singapore. Hence the country has established infrastructure and geographic advantage that could serve as a physical location to trade LNG. Regulatory framework and free-market practices in Singapore are a key strength to a potential LNG hub.

A liberalized market is key to the mechanism of trading and support of a hub. Japan has begun efforts to liberalize the power and gas markets so that more competition develops. Physical interconnects between isolated gas markets within Japan are being built to smooth market dislocation and price signals. The government efforts involve adding flexibility to LNG contracts by pushing for elimination of destination clauses. In addition, third-party access to infrastructure is being pursued. Assuming these measures are all successful, the largest remaining question for Japan will be how it would react in a high-demand/low-supply situation. Would they defend the function of the hub, allowing LNG to flow away from Japan to the highest bidder, or would they protect Japanese customers through its historic security of supply mandate?

China has also made efforts toward establishing an LNG hub at Shanghai. China has the highest forecasted absolute growth rate for natural gas consumption in the world. However, price controls both on upstream production and demand sectors, have been a key feature of government policy and limits the effectiveness of a potential hub. The Shanghai Petroleum and Natural Gas Exchange (SHPGX) was established in 2015 and trades less than 10% of Chinese gas demand. In August 2017, the platform was used to market a small volume of excess LNG, in lots as small as 20 tons. Further deregulation and free-market based principles could support China as an LNG hub. However, like Japan, as a net consumer with security of supply concerns, a functioning hub would require LNG to flow to the highest bidder, which might not always be Chinese.

An evaluation of conditions for LNG hub development has been prepared by KPMG and shows that Singapore is closest to meeting those requirements. A deterring negative factor is the small size of their market and minimal pipeline gas available. However, Singapore has proven to be an effective market for trading oil, with also limited infrastructure on a global basis. Japan and China have less developed criteria toward a competitive market, mainly around establishing trusted regulatory and free-market mechanisms.

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1 KPMG Developing Liquidity in the LNG Market, January 2017
2 US EIA Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region, March 2017
3 Interfax CNOOC teams up with SHPGX to boost LNG sales - August 2017
Source: KPMG Developing Liquidity in the LNG Market, January 2017

The financial side of trade has also been progressed by Singapore in the establishment of the SGX LNG Index Group SLingG – LNG price index and derivatives.

In addition, Platt’s assessment of LNG markets in its JKM (Japan Korea Marker) and swap market are also gaining momentum. The JKM volume has more than doubled in the last year. Financial trade of LNG can occur anywhere to support the physical trade.
5. Other potential Hubs

There are others LNG trading points that although there are a huge volume of Over the Counter (OTC) transactions, they are not considered yet to be LNG Hubs, because there is no pricing list of the transaction.

This is the Spanish case, where the 60% of total OTC transaction is linked to LNG terminals, with a volume of 260 TWh. This implies that in Spanish LNG terminals there is enough liquidity by trading gas, and therefore there is a great opportunity to transform Spanish LNG Terminals into an LNG hub and to become the region’s leaders in this field. This opportunity is even higher due to the evolution of the organized natural gas market, which from 2018 will list monthly (starting in M+2), quarterly, seasonal and yearly physical products. This will contribute to the completion of the product and price curve in the Iberian natural gas market, and facilitate the development of an LNG hub.

6. Conclusion and recommendations:

Establishing a true functional hub for LNG would increase liquidity. The real challenge will be to find a location that can always have a buyer and seller ready to transact. The pipeline hubs by their geographic nature have direct supply and direct offtake, hence there are active buyers and sellers ready to transact always. For a hub in a market such as China or Japan, which require net consumption of LNG, there may be times when supply is short and players are unwilling to release cargos into a secondary market. Singapore provides a more neutral location between buyer and seller with a widely accepted free-market environment.

A remaining question, beyond whether an LNG hub is achievable, is whether NBP or TTF can serve as a proxy hub, via shipping differential, to the world LNG market. The lesson from those existing gas hubs is that trust in the underlying market takes time to develop and must be guarded with strict protocols. Players will gravitate to the most attractive hub which will benefit the market: all buyers and all sellers.
Chapter 2 – Capital Costs

1. Introduction

While no project proponent (or its lenders) is currently willing to pursue final investment decisions on any export scheme without guarantees that sufficient contracts are in place to secure a return on their investments, securing demand itself is rarely the main issue for a project (although securing demand at a price acceptable to both parties is). While the concerns about future demand for LNG are certainly warranted, the more worrying trend lies in the rising costs of liquefaction and onshore regasification projects. In the last 10 years, the skyrocketing capital costs have challenged the viability of projects for many proponents.

The recent combination of high development costs and low gas prices is not sustainable, with the LNG industry risking losing energy market share unless costs are reduced. LNG project costs for new greenfield developments have escalated to the extent it has been difficult for buyers to accept the price point and for the developers to find an attractive investment.

LNG producers worldwide are struggling to make new projects stack up economically, enabling them to move towards final investment decisions, with customers wary of locking themselves into long-term contracts that could end up costing much more than spot LNG over the next few years, given the increasing supply that is expected to prevail over the next several years. Players seeking to weather this environment successfully and position themselves optimally for the longer term will need to materially reduce the development costs of new liquefaction projects. This was not a make-or-break issue for producers when prices and demand were supportive, however it is of critical importance and producers today are more reluctant to approve LNG projects in remote areas that have poor infrastructure, scarce key resources, and high construction costs. Rather, they must narrow their focus to only the most competitive projects and implement cost management measures to materially reduce development costs.

The LNG supply chain is an expensive operation, involving the pre-treatment, liquefaction, storage, shipping, storage and regasification of gas. The capital costs of this supply chain have increased substantially over the past decade, thereby impacting the liquidity of LNG with many export projects and land based import projects being deferred or delayed. The largest cost component of the LNG value chain (comprising more than 70%) is the liquefaction plant and with many of the large scale greenfield liquefaction projects being planned today (such as those in Russia, East Africa, Western Canada and Alaska) involving complexity and location issues, their high unit costs will challenge progressing those developments. It should be noted that the majority of the new LNG projects included in the exceptionally high unit cost category, are greenfield LNG complex projects, constructed in remote locations (many on offshore islands), with specific logistical and environmental sensitivities, and high local cost bases. They also involve extensive and expensive upstream production facilities and long pipelines, so the cost of getting the feedgas to the liquefaction plants has been a large part of the cost blow-outs, particularly for the Australian plants.
As the LNG industry looks at the next wave of LNG plants to come on-line post 2020, the question is whether the high unit costs experienced on many recent remote location greenfield LNG projects will continue, or whether cost reduction strategies can successfully reduce costs.

This chapter firstly documents the capital cost trends across the LNG supply chain (for liquefaction, regasification and shipping), then secondly identifies ways that the LNG industry can work to reduce (or at least contain) rising capital costs.

2. LNG unit capital cost trends

Reliable data on historical capital cost trends for facilities across the LNG supply chain (for liquefaction, regasification and shipping) is difficult to pinpoint since costs vary widely depending on location, extent of processing required and whether a project is greenfield or a brownfield expansion of an existing facility (further background regarding these variables for liquefaction plants is provided in Chapter 2.1.3).

With most infrastructures already in place, brownfield projects cost much less than new greenfield developments. To explain the main difference between brownfield and greenfield projects:

- A **brownfield** development involves the adding of gas pre-treatment and liquefaction trains to an existing plant, with infrastructure (including LNG storage tanks and loading jetty) already in place. Most of the US export plants under construction are existing import terminals, with LNG storage tanks, jetties and other infrastructure, to which liquefaction trains are being added (and they require minimal gas pre-treatment process units – due to their feedgas being of pipeline quality).

- A **greenfield** project is a complete new facility built from scratch on unused lands where there is no need to remodel or demolish an existing structure. Many Greenfield developments also process sour rich raw gas which requires extensive gas pre-treatment, such as condensate and LPG recovery, sour gas removal and potentially sulphur recovery. Greenfield developments in remote locations and/or in under-developed countries may also require extensive port development, dredging, airfield, accommodation etc. Greenfield LNG developments in Arctic locations also require extensive winterization and suffer from construction in cold (and in winter dark) working conditions.

By way of cost comparison the greenfield Corpus Christi plant being executed by Cheniere in Texas is estimated to cost US$1,050 to 1,100 per tonne of annual production (tpa), compared with the unit cost of about US$800/tpa for Cheniere’s Sabine Pass LNG project in Louisiana, which is a brownfield conversion of their LNG import terminal, which benefits from existing LNG storage tanks, marine berths and buildings. Expansions at Cheniere’s facilities would cost about US$500-600/tpa, significantly cheaper than greenfield projects because of the ability to use existing infrastructure. (unit costs attributed to Cheniere CEO Jack Fusco during a May 2017 earnings call; as reported by Argus Media 5May2017).

2.1 LNG liquefaction plant costs
The cost of LNG liquefaction plants has almost tripled over the past 10 years, an escalation rate that is almost twice that experienced by the oil and gas sector in general. While there are clearly evident reasons for some of these cost increases (such as those projects implemented in high cost countries and at remote locations), causes of other increases in cost are less clear (and outside even the downstream industry ‘inflation’ indices tracked by the IHS Markit Downstream Capital Costs Index - DCCI - detailed in Chapter 2.1.4).

Various attempts have been made to document the capital cost of building new LNG liquefaction facilities, however, regardless of their source and validity, the data all highlight this upward trending in LNG facility unit capital costs.


The following figure from the IGU World LNG Report – 2017 Edition highlights the average unit capital costs of LNG liquefaction plants (in US$/tpa) sorted for completion in three timeframes, and highlighting the increasing costs over time, for greenfield and brownfield onshore developments and for floating facilities.

Source: IGU World LNG Report – 2017 Edition Figure 4.11

Although there is unit cost data for floating LNG liquefaction facilities included in the above figure, there are too few LNG FLSOs (floating liquefaction, storage and offloading vessels) being executed to enable any conclusions to be drawn with regard to their capital cost performance. The FLSOs being implemented range in complexity, size and cost from Shell’s 3.6Mtpa Prelude at the upper end to Exmar’s 0.5Mtpa barge at the lower end. The projects are:

- Shell : Prelude (offshore Australia)
- Petronas : PFLNG1 (offshore Sarawak) & PFLNG2 (offshore Sabah)
• Golar : Hilli Episeyo (offshore Cameroon)
• Exmar : Caribbean (nearshore Iran)

2.1.2 – Wood Mackenzie database

The figure below shows initial unit capital cost data points (in US$/tpa) for liquefaction plants built globally since 1965, interpreted from Wood Mackenzie data (escalated to a common base year).

Source: interpretation of Wood Mackenzie's data 2017

The data has been identified by project in two major groups, with the blue diamonds denoting complete LNG plant facilities including the liquefaction train(s), storage tanks, jetty, offsites and utilities (greenfield developments) and the red diamonds denoting primarily the addition of liquefaction trains to existing export or import terminals (brownfield developments).

The project unit costs can be further sorted into “normal cost” projects and “high cost” projects:

• The LNG plant datapoints outside of the shaded box identify “normal” cost projects. Within this category are brownfield US LNG projects, such as Sabine Pass, Freeport, Cameron, Cove Point and Elba Island (where liquefaction facilities are being added to existing LNG import and regasification terminals).

• The LNG plant datapoints inside the shaded box highlight recent “high cost” greenfield projects. These projects are located in remote areas, are complex and have a high construction cost base due to their location (and in the case of Australia, there has been strong competition for labour resources and the use of foreign construction workers is restricted):
- The costs of the Australian projects reflect the complexity of these projects, with their remote locations (e.g. Gorgon, GLNG, APLNG and QCLNG are located on environmentally sensitive islands, with all construction workers and materials being transported by boat to the islands).

- The PNG project is complex with local land ownership and workforce issues and a remote location (requiring substantial infrastructure including an airfield and operations accommodation).

- The Snohvit project is very complex, located on a remote island in northern Norway and using a new liquefaction process. As well, both Snohvit and Gorgon projects include very expensive CO2 removal and disposal facilities. Yamal and Snohvit are both located north of the Arctic Circle, in remote areas with a very short summer construction period.

- The Angola project has its own particular problems and suffered significant delays, which have impacted its cost.

- The Prelude and Petronas PFLNG1 projects are prototype floating LNG developments, with project costs including upstream facilities.

A continuation of these higher costs for remote and complex projects will jeopardise the chance of new projects in similar locations being sanctioned and the LNG industry needs to reduce costs for such projects to remain competitive.

Similar unit cost data to that presented above is available in the February 2014 Oxford Institute of Energy Studies publication *LNG Plant Cost Escalation* which provides unit capital costs of a range of LNG liquefaction plants (in US$/tpa) completed since 1969, for both complete (greenfield) and liquefaction only (brownfield) facilities, and highlights the growing unit costs of those projects executed in recent years.

### 2.1.3 - LNG liquefaction plant cost variables

As outlined in KBR’s 2007 LNG15 technical paper “LNG Liquefaction—Not All Plants Are Created Equal”, comparing LNG liquefaction plant capital costs on a US$/tpa basis is fraught with danger.

Sourcing accurate and consistent cost data to conduct benchmarking is hard for any project. For LNG projects there are a wide range of potential inclusions/exclusions that must be considered and only a few of these are transparent when project capital costs are cited. While some LNG liquefaction plants may be very similar, there are many variables that need to be considered when comparing liquefaction projects, including:

a. While LNG export plants are referred to by their throughput (in Mtpa), what isn’t transparent is the basis for that quoted capacity. There is no consistency in how companies quote their plant throughputs, with some using Nameplate Capacity while others quote Annual Contract Quantity etc. There is also no consistency with regard to use of metric tonnes, Imperial tons or US short tons.
b. Comparing unit costs for LNG trains constructed over 30 or 40 year period is difficult (as many factors come into play; actual inflation versus CPI type numbers, hungry versus busy EPC contractors, lump-sum turnkey versus reimbursable contracts etc).

c. One of the features of many of the LNG liquefaction projects recently built, or being proposed, is that they are located in environmentally and/or culturally sensitive areas, distant from their undeveloped gas reserves. All of the recent Australian projects and Yamal, and most of the LNG projects being considered in Western Canada, East Africa, Russia and Alaska, fit within that description. The projects have to support an integrated supply chain including the liquefaction plant, upstream development and many times the pipeline construction too (unlike the LNG projects being developed in the US Lower 48 States, which are generally able to take advantage of the existing gas production pipeline network for their gas feedstock).

d. Whereas most LNG liquefaction/export plants process “raw” gas, from dedicated upstream and pipeline facilities, the US LNG export projects are sourcing their feedgas off existing pipeline networks from which the majority of contaminants and richer hydrocarbons have been removed, which simplifies their feedgas pretreatment requirements.

2.1.4 Oil & Gas Industry Plant Cost Escalation

Between 2003 and 2008, actual LNG liquefaction plant building costs more than doubled (some sources would indicate up to 3x), this was the highest rate of inflation in the LNG value chain and a major reason behind delays in the FID decisions of many LNG developments.

The EPC (engineering, procurement and construction) business serving the hydrocarbon processing industry experienced abnormal price escalation due to concurrent high demand for their engineering and construction services, along with rising material and labour costs. This dramatic increase in LNG plant construction costs was partly a result of the sector’s overheating and the high growth rate created "demand-pull" inflation in construction costs as it taxed the availability of qualified contractors, process equipment manufacturers and specialty materials suppliers.

This “hyperinflation” (abnormally high escalation) that occurred with oil and gas industry projects in general and LNG projects more specifically, has warped typical escalation factors such that escalating LNG project costs from say 2002 to 2017 with ‘normal’ escalators, would substantially underestimate the 2017 cost. The growth in LNG plant prices has outstripped that general process plant escalation, as typified by the IHS Markit Downstream Capital Costs Index – DCCI (the DCCI being one of the few available indices which are specifically tailored for the process plant industry and which also attempt to incorporate ‘market factors’).

The IHS Markit DCCI tracks the costs of equipment, facilities, materials and personnel used in the construction of a geographically diversified portfolio of 40 refining and petrochemical construction projects around the world. Unlike its competitors (such as
the Chemical Engineering and Marshall&Swift indices shown below) the DCCI captured most, but not all, of the rapid hyper-inflation experienced during the early to mid-2000s.

While the level of abnormal escalation is reported as easing (refer to the IHS Markit DCCI chart below), actual experience with tendered prices for LNG liquefaction plants has been that even though the DCCI captures aspects of hyperinflation incurred over the 2000 to 2017 timeframe, the actual cost increases in that period far exceeded the DCCI, with tendered prices for LNG liquefaction projects today remaining at more than triple what they were in the early 2000s.

The DCCI peaked at 204 in 3Q2014 and the DCCI was 193 in 4Q2017.
2.2 - LNG import and regasification terminal costs

LNG import terminals have traditionally been built onshore, with multiple LNG storage tanks and large vaporiser capacity (with several terminals in Asia having more than 2 million m3 of storage capacity).

Recently, due to the high capital costs and long execution durations of onshore terminals, FSRUs have become increasingly popular, because of location flexibility, duration of the charter and since the capital costs are less (while it is noted that the opex costs are higher). The need for fast access to imported gas (as LNG), increases in the cost of land based terminals, and the reluctance towards committing to long-term agreements, has paved the way for the rapid rise in Floating Storage and Regasification Units (FSRU’s) in recent years. FSRUs best suit the interest of countries that have stagnant or declining gas production or countries that are seeking extra gas supplies over the short term and which have limited capital expenditure. FSRUs also offer temporary solutions for countries that may later opt for onshore regasification facilities in the longer term.

The capital cost of a new FSRU based terminal can typically represent less than 60% of an onshore terminal and FSRUs can be delivered in a shorter time, as a result of not requiring onshore storage tanks and other infrastructure. The project schedule to
construct an onshore terminal is driven by the construction duration of the LNG storage tanks, which is typically 36-40 months, whereas newbuild FSRUs typically take 27-36 months (with conversions of older LNG carriers typically taking 18-24 months). Government approvals can also be much shorter for FSRU based import terminals, which require minimal (in some cases no) land.

On the other hand, while FSRUs involve less Capex they are more Opex intensive, while both the storage and regasification capacities for FSRUs are limited. Furthermore, since FSRUs are located in open waters, weather conditions have an impact on operations.

For small volume LNG importers, an FSRU can be leased for a short term (5 years or less) and even for just summer or winter peak periods. Through use of FSRUs, LNG can thus penetrate non-traditional markets which may not be able to justify the commitment (of cost and time) required for a large land based terminal.

2.2.1 - IGU World LNG Report – 2017 Edition

Capital cost data for onshore regasification terminals is difficult to source, however from the limited data available, it is apparent that there has also been a growing cost trend similar to (but not as dramatic as) that experienced with liquefaction facilities, because these facilities typically use simpler technology and are located closer to available labour pools.


![Graph of Capital Costs for Onshore and Floating LNG Regasification Facilities]

Source: IGU World LNG Report – 2017 Edition Figure 6.11
2.2.2 – Onshore LNG regasification terminal costs

Many of the cost differentiators highlighted for liquefaction plants above also apply to land based regasification plants, with a number of unique factors to be considered including; local environmental limitations (e.g. can seawater be used as the heating medium?), pipeline gas heating value requirements (is enrichment or derichment required?) and whether the LNG vaporization facilities are located in a warm climate or a cold climate region.

Over the past 10 years, construction costs for land based import terminals (on a capital cost per unit of send-out capacity) have risen an average 12% per annum for both grassroots projects and expansions alike. Storage tanks are the single biggest contributor to these cost increases for onshore terminal costs and in many cases this has led to poor economies of scale at smaller grassroots facilities, as minimum storage capacity is dictated by the expected size and frequency of incoming ships rather than the terminal’s actual send-out capacity.

While storage costs are the main driver behind the inflationary pressure, other factors also come into play. Equipment costs and lead times for essential items such as pumps, heat exchangers and compressors have also continued to rise due to constraints on the manufacturing side and higher raw materials costs. As well, EPC contractor demand has remained at unprecedented levels throughout the entire energy industry.

2.2.3 – Floating Storage and Regasification Unit (FSRU) costs

FSRUs have a number of advantages over land-based LNG facilities; they are quicker to build, have lower capital cost, can be moved from one location to another as business demands, they remain largely unseen by the public and are not a permanent feature of the landscape (although as noted above, FSRUs are more Opex intensive).

While FSRUs tend to have lower capital costs than onshore import and regasification terminals, for LNG import facilities required for 10 years or longer, a fixed onshore terminal is usually more cost effective, due to their lower Opex costs.

Five of the first FSRUs were based on converted older LNG carriers (LNGCs), however more recently most FSRUs have been purpose-built units. Recently there has been renewed focus on conversions, because as the LNG shipping market has deteriorated, older LNG carriers are becoming harder to employ and are therefore seeking alternate use. Currently there is an oversupply of LNGCs, with a number of 1970s and 1980s-built vessels laid-up with potential plans for conversion to LNG FLSOs or FSRUs.

FSRU conversions are lower cost (conversion of an old LNGC costs between US$60 and US$100million, plus purchase of a 2nd hand LNGC - typically using 30 year and older LNGCs costing $18 million to $20 million) and are faster to market.

New FSRUs are now being built in the range of 138,000m³ to 263,000m³ LNG storage capacity, with onboard regasification facilities in the range of 400mmmscf/d to 1bscf/d and recent FSRU newbuilds cost between US$260 to $400million (depending on storage/regasification capacity), which is a premium on the cost of a newbuild LNGC,
due to the additional pumping, regasification and heating facilities required to regasify the LNG. This equates to a range of US$1,500 to 2,200/m³ of LNG storage capacity.

Note that in addition to the purchase cost (or lease costs) of an FSRU, also to be considered are the capital costs of the associated facilities required to support the FSRU. These include location specific facilities such as; a jetty or berth or mooring, gas pipeline from FSRU and even potentially a breakwater.

2.3 - LNG Carrier (LNGC) newbuilding costs

Unlike the rising capital costs of liquefaction and regasification facilities, strong competition between Korean and Japanese (and more recently Chinese) shipyards, and technical developments in the construction of LNGCs, and a “design one build many philosophy”, have contributed to a downward trend in cost of building these vessels.

LNGCs are among the most sophisticated and expensive merchant ships and their construction has traditionally been limited to a few shipyards, due to the technologies required to store and transport the cryogenic LNG cargo. The requirement for continuous cargo cooling, as well as avoiding cargo evaporation, requires very good thermal insulation of the storage tanks and the tanks are manufactured from expensive high nickel stainless steel or aluminium.

There are also only a few technology providers for the containment systems, with those on the market essentially the same for the last few decades. However, recently the designers and builders of both Moss-Rosenburg spherical and GTT membrane containment ships have developed more fuel efficient propulsion systems which require correspondingly more efficient containment insulation systems, as these new propulsion systems use less fuel (with many of the propulsion systems being either dual or triple fuel compatible).

Competition among shipyards and technical development have both contributed to the continued reduction in the unit cost of LNG carriers. In recent years the unit cost of an LNG carrier of conventional size has been reduced from around US$2,000/m³ in the mid-1990s to about US$1,150/m³ today. In gross dollars, construction costs in 1995 were around $270 million for a 135,000-cubic-meter-capacity ship and today the cost of building a 170,000m³ LNG carrier amounts to around US$200million.

2.3.1 - IGU World LNG Report – 2017 Edition

The following figure from the IGU World LNG Report – 2017 Edition shows the capital costs of newbuild LNG carriers (in US$/m³ of cargo capacity) for delivery between 2005 and 2015, for various propulsion systems; slow speed diesel (SSD), dual-fuel diesel electric (DFDE), tri-fuel diesel electric (TFDE), Steam and M-Type Electronically Controlled – Gas Injection (ME-GI):
Note that the surge in TFDE LNG carriers around 2014 was due to the ordering of 15 ice-class tankers for the Yamal LNG liquefaction project. These vessels cost approximately US$320 million each, or US$1850/m³.

**2.3.2 – World LNG Shipping Jan/Feb 2017**

The following figure shows the capital costs of LNG carriers (in US$) for future delivery, for various propulsion systems and LNG capacities (and also included are costs for newbuild FSRUs):

Source: IGU World LNG Report – 2017 Edition Figure 5.12

Source: World LNG Shipping Jan/Feb 2017
3. Enhancing liquidity

The objective of this chapter is to document how the industry might enhance the liquidity of LNG by reducing capital costs across the LNG supply chain.

Many of these measures have worked, either in the oil and gas industry internationally, or in another sector; however the size of the cost gap is large enough to suggest that closing it will require significant effort of all parties involved.

The steps producers can take to put themselves on the right path, include the following:

3.1 – Shared infrastructure and site selection

- Encourage cooperation among operators. Historically, there has been limited cooperation among developers; independent plants have been built side by side, resulting in substantial duplication. A more cooperative approach, one that leverages shared facilities, could optimize design and construction spending and generate meaningful reductions in capital and operational spending. Cooperation between the owners of different projects in the same area should consider taking advantage of synergies and shared use of facilities. The most obvious example of lack of cooperation is the QCLNG/GLNG/APLNG two train baseload plants built next to one another in Australia on Curtis Island, where there were "missed opportunities" for the three projects to collaborate on common facilities. Sharing their infrastructure would have resulted in major cost savings; yet there has been triplication in most project areas, with each of these projects ended up going it alone.

- Carefully consider the full impact of chosen liquefaction plant sites. Many of the cited high cost liquefaction projects have been afflicted by significant cost and schedule blowouts, exacerbated by their selected locations. For example, the Wheatstone project site is located on a remote floodplain (requiring substantial site filling to raise the level of the land and extensive piling), Gorgon is located in a Class A nature reserve on an island (involving strict quarantine and environment management requirements), while the three Gladstone projects (QCLNG, GLNG & APLNG) and Snohvit are all also located on islands. Being located on islands added significantly to their project costs (due to the requirement to transport all personnel, equipment and materials to these islands by ferry/ship/barge). For those Gladstone projects, working together, along with involvement from the State Government, to construct a bridge across the Narrows to Curtis Island, would have drastically reduced construction (and ongoing operations) costs.

- Another potential cost consideration for an LNG regasification facility is whether it can be integrated with a power plant to recover their waste heat for vaporising the LNG. This has seldom been practiced, however with current high energy prices and concerns for carbon emissions, integration with waste heat from power plants can be attractive. For example, the recently completed Dunkirk LNG regasification terminal includes a 3 meter diameter 5 kilometer tunnel from
the nearby Gravelines nuclear power plant to the LNG terminal, supplying discharged hot water to the terminal for regasification of the LNG.

3.2 – Technology & project execution

- Support the development and standardization of floating LNG technology. The LNG industry is in the early stages of developing and testing offshore liquefaction. Once the technology has been proven, industry participants will need to work to standardize the processes before its full potential value can be realized.

- Foster competition among suppliers. In recent years, the industry has been characterized by limited competition among suppliers, especially in such critical components as refrigeration compressors and large heat exchangers. By fostering competition and supporting a larger supplier base, the industry could put downward pressure on prices. This would be facilitated by increased standardization of plants.

- Rethink the company’s technology strategy. Industry participants have emphasized new technologies that have boosted scale and thermal efficiency. These complex technologies, however, are very expensive and relatively difficult to standardize. Currently, the greater efficiency that they deliver also translates into relatively low value, given depressed LNG spot prices. Producers must therefore reassess these technologies from a cost-benefit perspective.

- Develop modular and/or standardized approaches to plant construction. The industry has evolved toward the construction of very large, one-of-a-kind plants that have limited potential for standardization. Companies could potentially reduce construction costs considerably by turning to smaller units that permit modular plant construction and more standardization.

- Use steel or concrete liquefaction facility barges built under workshop/fabrication yard conditions, where a large labour pool and experienced fabrication companies exist (to take advantage of the lower cost base and higher productivity), with the barge mounted facilities being floated into position and permanently grounded (such as was utilized for Snohvit LNG). This concept is proposed for the Texas Brownsville LNG and Russian Arctic-2 LNG projects.

- Use aeroderivative GT compressor drivers, which are more fuel efficient and have lower emissions. Aeroderivatives were first used for LNG mechanical drives on Darwin LNG and have since been applied to PNG LNG, QCLNG, GLNG, APLNG, Wheatstone, Sabine Pass and Corpus Christi liquefaction trains. They have also been proposed for Shell’s LNG Canada and Lake Charles LNG projects.

- Apply the “design one, build many” concept which has had some notable successes, however the LNG industry could do more. While on the surface this philosophy makes sense, the reality is that due to differing feedstocks, ambient conditions and LNG product qualities, LNG trains are generally bespoke designed. Bechtel and ConocoPhillips offer this concept with their “LNG template” based on their experience in designing, building and turning over LNG projects based on
the proven ConocoPhillips LNG liquefaction process. The template addresses such critical areas as project planning, building on proven experience, effective technology selections, aligning of objectives between the owners’ and the contractors’ teams, and optimal contracting and execution strategies. This approach has been used successfully on such LNG projects as Atlantic, Egypt, Darwin, Equatorial Guinea, Sabine Pass and Corpus Christi, which mostly have been completed on budget, ahead of schedule, and quickly met their design objectives.

- Implement Lean Project approaches across the entire development process. The LNG industry has so far placed limited emphasis on Lean approaches, but these have led to reductions of as much as 30% in development costs in other industries, such as mining. LNG developers and their contractors should consider how they can deploy Lean approaches more broadly.

- Simplify the company’s approach to the project design phase. LNG developers have typically used multiple front-end engineering and design firms, and complex contracting practices, in project design. This has often increased project length and management costs. A simpler, streamlined approach could lead to a shorter development schedule and lower costs.

- Project teams have many ways to improve the productivity of capital, including scope reduction, construction excellence and more efficient procurement. Too often, they review these opportunities only before major decision gates, or after an unsuccessful visit to one. Instead, similar to an operating asset, the development project itself needs a constant improvement process. Opportunities to optimize value need to be managed throughout opportunity generation, prioritization, solution generation and implementation. Project leaders should resource and govern these to add value to, rather than slow down, the overall project process.

- Too many capital projects start with a cost estimate defined by the engineering and design teams. Taking the reverse approach; that is understanding what investment is feasible and then deciding what can be done within those constraints (design to cost), is more realistic in a low-oil-price environment. In fact, setting the cost below a reasonable level spurs creativity and preserves capital until oil prices recover. There have been examples of highly innovative engineering concepts in LNG development forced by top-down design-to-cost directives.

3.3 – Life extension & debottlenecking

- LNG liquefaction trains have longevity and, instead of building new liquefaction trains, a life extension program can provide further decades of economic operation. After 20+ years of operation, many LNG liquefaction plants have undertaken life extension programs to increase their asset's useful life. Examples of successful programs include those undertaken by the Alaska, Brunei, Arun, Bontang, North West Shelf and Das Island LNG plants, which enabled
these plants (built in the late 1960s and early 1970s) to continue operating for another 20+ years.

- Debottlenecking is another obvious technique to free-up additional liquefaction capacity at a lower unit cost. Publicized examples of LNG trains which have been debottlenecked include; Sakhalin, Malaysia LNG Dua, Qatargas T1,2&3, Arzew GLZ1, Alaska and North West Shelf T1,2&3. While it is believed that process plants designed in the computer era have less lagniappe within their designs, debottlenecking is an area that warrants investigation.

- Where feed gas shortages threaten plant closure, sourcing gas from further afield (even from neighboring countries) may extend the useful life of existing trains. This is being actioned by Atlantic LNG for their plant in Trinidad (where an agreement has been reached to process nearby Venezuelan gas through existing trains) and is being studied by Oman LNG (where consideration is being given to importing gas from Iran to keep their trains operating). Another example is Woodside with their Northwest Shelf facility, where after previously investigating the Browse LNG development (via a newbuild stand-alone LNG facility); they are considering building a 920km pipeline that would connect the Browse fields with the existing Karratha LNG plant. Woodside is also reported to be investigating tolling options to process gas from other gas joint ventures in the region, through either their North West Shelf facility or the nearby Pluto facility.

### 3.4 – Small scale LNG (SSLNG)

- On a positive note, smaller markets are emerging for LNG in developing economies that need bite-sized pieces of supply rather than the huge chunks that come with large new projects. New users are also emerging in the marine and transport sectors, which is broadening sales beyond the traditional area of power generation. While the SSLNG market is relatively immature, several major energy companies are already involved in SSLNG.

- SSLNG has the potential to enhance LNG liquidity, as unlike the massive LNG export and import terminals situated on the coasts, which rely on long-term shipping contracts, the “small-scale” variety provide LNG supply to end-users in places where traditional infrastructure does not reach. There are three major end uses for SSLNG: marine fuel (bunkering), fuel for heavy road transport, and power generation in off-grid locations. Small-scale LNG will increasingly become a key part of the gas industry’s portfolio for exports in years to come. Smaller plants are being constructed in response to the growing market demand for smaller cargoes, which are both easier to finance and also allow the buyer the option to diversify its supply.

- SSLNG can grow the market for LNG as a cleaner and lower cost fuel, and by enabling new LNG producers to get into the business at lower unit costs, with the ability to incrementally expand their liquefaction capacity. In contrast to large-scale LNG projects, SSLNG initiatives offer investors more immediate and potentially attractive returns in the medium term. The proven technology allows
SSLNG projects to offer a “plug and play” service with lower investment requirements and accelerated commissioning schedules, and that leads to reduced uncertainty on the project execution timing. Second, SSLNG is scalable, meaning operators can easily add capacity to serve increased demand while gaining supply chain synergies. That makes SSLNG an ideal way to meet short-term fluctuations in demand. And finally, precisely because of this flexibility, SSLNG can stimulate demand in areas of the market that were previously unsuited to LNG as a fuel source, such as off-grid power generation on islands and in remote areas.

- The SSLNG export market from the United States involves exports of small volumes of natural gas primarily to countries in the Caribbean, Central America, and South America. Many of the countries in these regions do not generate enough natural gas demand to support the economies of scale required to justify large volumes of LNG imports from large-scale LNG terminals via conventional LNG tankers. The small-scale natural gas export market has developed as a solution to the practical and economic constraints limiting natural gas exports to these countries. In October 2017 a bill was introduced into the US Senate which would fast-track the approval process for companies wishing to export relatively small-scale volumes of LNG to nearly any country - “without modification or delay.”

- Historically the majority of global LNG liquefaction capacity has been produced in large scale plants using processes licensed from either Air Products or ConocoPhillips, and engineered and constructed by a coterie of large international EPC contractors. Use of alternative SSLNG liquefaction processes, broadening of the community of EPC contractors (with smaller companies with sufficient experience and resources to undertake SSLNG projects) and constructing using modular units, is growing in popularity and shown to be cost effective. Current examples include:

  a. The Elba Island, Georgia, USA project with 10 x 0.25Mtpa Movable Modular Liquefaction System (MMLS) trains using Shell technology with a total capacity of 2.5Mtpa. Construction of the plant reflects the modular nature of the facility, initially installing 3 MMLS units and later 7 additional MMLS units.

  b. The Sengkang project being developed by EWC in Indonesia with 4 x 0.5Mtpa trains, each using Chart SMR technology.

  c. The Driftwood LNG Project being developed by Tellurian in Louisiana proposes to install up to twenty 1.3Mtpa trains using Chart SMR technology.

  d. Cheniere is changing the design of Stage 3 of its Corpus Christi LNG export facility, to incorporate 7 mid-scale 1.4Mtpa LNG trains using Chart SMR technology, instead of the approved 2 large-scale units using ConocoPhillips technology. The company plans to use mid-scale liquefaction opportunities as a way of reducing per-train construction
costs and making it easier to find offtakers to buy the capacity in smaller parcels.

e. The Golar GoFLNG concept for three small scale FLNG conversions (based on conversion of redundant LNG carriers) constructing 4x0.6Mtpa liquefaction trains using Black&Veatch PRICO technology, with the addition of side sponsons to create additional deck area. The first of these (the Golar Episeyo FLNG unit) was put into operation offshore Kribi, Cameroon in late 2017.

f. A small scale FLNG barge, built by Wison in China for Exmar with a single 0.5Mtpa liquefaction train using Black&Veatch PRICO technology on a newbuild hull. Originally built for the Caribbean LNG Project in nearshore Colombia.

4. Conclusions

Opportunities exist for reducing liquefaction (and to a lesser extent regasification) facility costs. While none of these represents a 'silver bullet' which will radically reduce costs overnight, there are reasonable expectations that some of these might work.

The availability of smaller parcels of LNG, produced in small scale LNG liquefaction plants, transported in small ships or trucks, and regasified in small-scale LNG terminals is lowering the costs of entry to the LNG business and increasing LNG’s liquidity. Small-scale LNG is growing at a fast rate and the global small-scale LNG market is projected to expand at a compound annual growth rate (CAGR) of up to 10.0% over the next 5 to 10 years, with this market expected to grow to approximately 100 million tons per year by 2030 (the International Gas Union forecasts a rise in annual global demand to 30 million tons in 2020, while Engie projects that demand will be 75 million to 95 million tons by 2030; per 18July2017 PwC paper “Small going big: Why small-scale LNG may be the next big wave”).
Chapter 3 – Shipping

1. Introduction

LNG is primarily a seaborne commodity and its global trade essentially depends on the availability of LNG maritime shipping capacity. For LNG sellers and buyers, unconstrained access to LNG shipping capacity through term or spot chartering of vessels or through the use of self-owned tankers is therefore of paramount importance.

In recent years, LNG shipping has evolved from a situation where LNG carriers were mostly project-dedicated and employed for point-to-point trades under long-term contracts, to a more flexible market, with shorter supply contracts and charter terms. As a result, global LNG trade has become more complex and the growth in available spot shipping capacity tends to indicate that liquidity has developed.

As spot and short-term LNG trade is poised to further increase with the advent of flexible volumes from the United States and of uncommitted volumes from our sourced, a liquid LNG shipping market is essential in order for companies to efficiently arbitrage between markets, manage portfolios and mitigate the risks associated with commitments to buy or sell LNG volumes.

The current LNG shipping market is driven by technical, logistical, commercial, regulatory, financial and political factors which can either constrain or reinforce its level of liquidity.

This Chapter identifies a path to greater liquidity of the LNG shipping market, by focusing on the three aspects below:

- What are the main characteristics and what is the structure of the LNG shipping market today?
- What are the current constraints adversely affecting the liquidity of LNG shipping?
- How could the barriers to liquidity be removed as the LNG market develops?

1.1. Historical characteristics of the LNG market

Historically, LNG shipping contracts have been based on “Long Term Time Charters” in conjunction with Long Term Sales and Purchase Agreements (SPAs). The usual duration of such time charters was usually of 15 to 20 years, in line with the duration of the SPAs. Under this model, new LNG ships were built to meet the start-up date of new projects and the charter rates were calculated in order to recover the capital investment over the duration of the project. As a result, LNG ships were designed based on the specifics of each project, and particular attention was paid to the compatibility between the vessels and the loading and unloading ports designated in the contracts.

The Fukushima crisis in 2011 increased Japanese demand for LNG quickly and unexpectedly which required significant incremental volumes from the Atlantic Basin to Japan. This put a strain on the global LNG fleet, bringing vessel utilization and charter rates to their highest levels. Following the decline in utilization from the highs seen around the Fukushima crisis, ship owners were looking for other ways to utilize LNG
ships which were no longer dedicated to specific long-term contracts. Another strategy was to build new LNG ships which shall be specifically utilized for spot or short-term transactions (speculative basis).

Today, LNG ships typically fall into three types of utilization patterns:

- Ships fully dedicated to a specific project,
- Ships basically dedicated to a specific project, with excess capacity shall be utilized for spot or short-term transactions, or
- Ships utilized for spot or short-term transactions.

It is expected that the demand for the last two categories will increase in the coming years, in line with the rise of flexible and uncontracted volumes.

Indeed, according to the “2017 World LNG Report” published by IGU, Non Long-Term Volumes (volumes traded under contracts of less than 5 years duration) have increased to 72.3 MTPA in 2016, accounting for 28% of total LNG gross trade, whereas such volumes represented only a few percent of global trade in the mid-1990’s.

1.2. Evolution of the chartered fleet

At the end of 2016, 121 new-build vessels were on order, with around 67% of the orderbook associated with charters of more than a year, while 44 vessels were ordered on a speculative basis.

Out of the 77 vessels in the order book at the end of 2016 designated as on charter, 20% were tied to companies that were considered an LNG producer (Sonatrach, Yamal, etc.), while LNG buyers made up 38% of the newbuild orders. The remaining charters comprised companies with multiple market strategies.

Going forward, the shipping market will have a steady decline in the chartered fleet due to the expiration of the current charters. The downward trend shown in the graph
above does not mean a halt in chartering activity, however it does mean more ships will be chartered under new conditions bearing in mind the structural changes that the LNG market is undergoing.

The chartering activity has continuously evolved over the recent years where spot and short-term charters have been dominating the fixture market. The mean charter period has fallen from 230 days in 2008 to 61 days in 2016.

1.3. LNG liquidity

1.3.1. Impact of LNG trade on shipping liquidity

The dynamics of LNG trade greatly affect the LNG shipping market and its liquidity. A number of new projects (refer to diagram below) have entered into operation since 2013, adding more than 60MMtpa (million tonnes per annum) to the market.
This increase in supply activates LNG trading and affects shipping requirements in a significant way (refer to graph below relating LNG shipping volume with LNG liquefaction capacity). The result has been an increase in the short term and spot market for shipping.

Source: Braemar
When analysing the liquidity of the shipping market, we look at the transactions which are made, the period of the transaction, the available fleet, the amount of production that enters into the market, the level of freight and other relevant factors.

The increasing percentage of flexible volumes is an opportunity for more efficiency in the shipping market but timing or physical constraints could jeopardize that.

Indeed, the operating rate has been decreasing since the market started signing more flexible contracts and more efficient ships entered the market. This can be explained by the uncertainty that flexibility generates in terms of shipping needs and the preference of actors to cover the charter rate risk. The post-Fukushima era experienced a hike in the operating rate since the reloaded volumes increased drastically and the cross-basin trips did as well. New tonnage has however outpaced the build-up in liquefaction capacity in recent years. As a result, in 2016, the amount of LNG delivered on a per tanker basis, including idle tankers, reached 0.62 MT compared to 0.73 MT in 2011.

1.3.2. Spot fixtures

The growth in liquidity began in 2013 as a wave of LNG new carriers were delivered by the shipyards, many without term engagements, adding length to the shipping market. In the years that followed, newbuild deliveries continued apace while aggregate global LNG trading volumes remained mostly flat. Trade volatility increased due to a disruption in trading patterns as traditional import markets saw little change in demand or even declined, and incremental growth came from new and quickly-developed markets.

In January 2014, around 14 vessels were competing for spot employment. By the end of 2015, the pool of vessels available for hire grew to over 30 vessels,
new import markets opened, and Pacific basin suppliers ratcheted up exports. By the end of 2016 the number grew to 35.

New import terminals and increasingly competitive LNG prices saw higher than expected imports into India, China, and the Middle East. While the global LNG trade increased in 2016 by 20 million tons, the average trade route distance decreased as new supply capacity came online in both the Atlantic (GoM) and Pacific basins. Spot charterer demand largely remained regional, and the average spot charter duration stayed low at 26 days in 2016, compared to 25 days in 2015 and 39 days in 2014.

Today, the number of vessels available for spot employment stands at 44 vessels, however the recent growth is because existing vessels have come off term charters, not speculative newbuild deliveries. Although the number of vessels competing in the spot market has grown by 27% over the last six months, spot fixture activity has remained flat. There have been 136 recorded spot fixtures during the first half of 2017, the same as in the first half of 2016. As the market becomes more liquid, short-term fixtures will be more prevalent. Total spot fixtures (a charter of six months or less) during 2016 reached an estimated 280 fixtures compared to 175 fixtures in 2015, with traders making up a third of all spot fixtures.

The following chart highlights the number of spot fixtures during 2016 and into 2017.

Source: Braemar AC Shipbroking

The following chart identifies the spot fixtures by type of player.

<table>
<thead>
<tr>
<th></th>
<th>1H 2017</th>
<th>1H 2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility</td>
<td>5</td>
<td>10</td>
</tr>
<tr>
<td>Trader</td>
<td>56</td>
<td>47</td>
</tr>
<tr>
<td>Major</td>
<td>40</td>
<td>31</td>
</tr>
<tr>
<td>Project</td>
<td>33</td>
<td>47</td>
</tr>
<tr>
<td>Shipowner</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Total</td>
<td>136</td>
<td>136</td>
</tr>
</tbody>
</table>

Source: Poten & Partners
1.3.3. Is excess capacity of shipping sufficient to guarantee a liquid shipping market?

The length of the shipping market is usually assessed by using the vessel multiplier, i.e. the multiplication factor to evaluate the size of the fleet required for a certain level of demand. The historical vessel multiplier for the global LNG market has averaged around 1.3 over time, which means that for each MMtpa of demand, 1.3 ships are needed to transport the corresponding LNG volumes.

Several observations however:

a) Some export patterns may require a higher vessel multiplier. This seems to be the case when LNG carriers are forced to use sub-optimal routes, to deliver to remote markets or when they encounter logistical constraints which increase voyage length and idle time. As an example, Sabine Pass exports experienced a vessel multiplier of 1.77 in 2016, which means that almost two vessels are required for each million ton of LNG exported. Rising LNG prices in the East in response to significant demand from China and Korea also resulted in additional arbitrage opportunities and ton miles as more US volumes headed further eastward. Approximately 1.9 vessels are required to carry US volumes to Asia, more than twice the number required to deliver Australian volumes.

b) The overall length of the LNG shipping market does not necessarily imply that the spot shipping market is also long. Vessels available for spot fixtures are generally identified as such and operated to this purpose, and sub-chartering a long-term chartered vessel on the spot market may often require both technical and contractual adjustments.
c) In order for a spot vessel to be chartered, it is preferable for the vessel to be already located in the loading basin or within a reasonable distance from the loading port. Otherwise, the potential margins maybe offset by the cost of moving the vessel to the adequate location. As a consequence, the estimated length of the spot shipping market may differ from one region to another. As is the case for LNG trade, liquidity might be there, but it might be patchy.

1.4 LNG Carrier operating efficiency

Historically, LNG has been a bulk, long-haul business on fixed shipping routes, however now we are entering a new era in which LNG is much more widely produced, is shipped from and used in a wide diversity of places, in a wide diversity of ships, for a wide diversity of purposes.

The increase in length of shipping routes (with many routes nowadays more than twice the historical average trading distance for LNG voyages) and a greater focus on operating efficiency, have meant that LNG carrier designers, shipyards and shipowners are designing ships with; improved machinery configurations requiring lower boil-off rates (which in turn need more efficient containment system insulation), higher levels of energy efficiency (providing reductions in fuel-related costs, resulting significantly improved environmental footprints) and increased cargo capacities.

This is only the beginning of a new period of innovation in how we transport LNG. Under consideration are more tank types, more containment types, more propulsion options, more sizes of ship, and more speciality ships, like the vessels for the Yamal project that can break heavy Arctic ice using astern azimuth propulsion.

These new vessel concepts are better suited to future trading patterns than existing vessels.

1.4.1 Improved fuel efficiency

Propulsion systems for LNG carriers have diversified rapidly in recent years in response to accelerated energy-saving demands triggered by lengthening voyages and tighter environmental regulations.

For LNG ships built up to about 20 years ago, there was little incentive to seek more efficient propulsion plants because the state of the cargo tank insulation technology was such that, on a laden voyage, the natural boil-off gas flow provided approximately 100 % of the fuel requirements - i.e. even if more efficient plants were available, they could not be used without wasting boil-off gas.

Steam turbines have been a dominant form of propulsion on LNG carriers (LNGCs) for over forty years and used boil-off gas as fuel for boilers – and this was the reason for installing steam plants as the means of propulsion of LNG carriers. However, these older steam propulsion systems are inefficient and impact both emissions and the vessel’s operating expenses adversely.
Improved efficiency is being achieved through the application of new more efficient internal combustion and steam turbine propulsion systems. More recently internal combustion engines have been favoured, with the development of dual and tri-fuel diesel electric (DFDE and TFDE) and two-stroke gas engine (ME-GI & XDF) propulsion systems. These changes in propulsion systems have improved efficiency, provided redundancy and flexibility according to power demand and resulted in more cargo delivered.

Despite this trend away from steam turbines, both Kawasaki and Mitsubishi both took up the challenge and continue to offer attractive propulsion steam turbine solutions for the LNG carrier market using reheat-type steam-turbine propulsion plant which offer a significant improvement in transport efficiency. The Mitsubishi Heavy Industries (MHI) Sayaendo concept offers a major advance in fuel efficiency through the adoption of MHI’s new ultra-steam turbine (UST) propulsion plant, while with their Sayaringo STA(GE) concept, incorporation of a hybrid propulsion system has boosted fuel efficiency by more than 20 per cent compared to the Sayaendo, and more than 40 per cent compared to earlier steam turbine based carriers.

The higher thermal efficiencies of these more efficient propulsion systems have reduced the fuel use, thus lowering the amount of boil-off gas (BOG) needed to produce that fuel gas. Whereas the typical boil-off rate (BOR) for the older steam turbine LNGCs was 0.15% cargo volume per day (v/d) or even 0.17% v/d, the goal of the new insulation systems is <0.10% v/d; a significant reduction (in fact the newer insulation systems are reported as achieving BORs as low as 0.07% v/d. To give added perspective to this progress, 1970s-built LNG tankers typically had a BOR of 0.25%.

These improvements in propulsion performance have substantially lowered fuel consumption and as a result enhanced environmental performance.

1.4.2 Cargo containment technologies
The rate of ‘natural’ boil-off for any given LNG carrier is primarily determined by the extent and effectiveness of its cargo tanks’ insulation, thus to achieve these lower BORs, more thermally efficient insulation is required and this has spurred enhancements to the principal LNG cargo containment systems.

Larger ships with membrane tanks remain the backbone of the LNG trades and the majority of LNG ship owners have selected the membrane containment system. Use of membrane containment allows a more compact ship to be constructed for the same cargo capacity and lower fees for passing through the Suez Canal. In addition, there is less windage (the part of the ship above water) subject to wind loading, leaving it less vulnerable to wind effects than the spherical tank designs.

The membrane type has become the most prevalent cargo containment technology in recent years, with the majority of the present global LNG carrier
fleets, and the new-build orders, having specified a Gaztransport & Technigaz (GTT) or Kogas membrane containment system. GTT has developed the latest evolutions of their Mark III and NO96 membrane technologies, with the aims of providing these required lower LNG cargo boil-off gas BORs.

Recent improvements in insulation and clever engineering have increased storage effectiveness. For example, the latest version of GTTs Mark III membrane technology (Mark III Flex+, a variant of the well proven Mark III), introduces an increased insulation thickness and an enhanced secondary barrier arrangement. The guaranteed daily BOR is reduced to 0.07%V/d via an increase in the insulation thickness (from 270mm to 400mm), while keeping the advantages of the mature Mark III technology.

Although GTTs membrane technologies dominate the containment system market, several other new developments have taken place:

- Korea Gas Corporation (KOGAS) has developed their own KC-1 membrane containment system, to provide Korean shipbuilders with a domestic alternative to the two established GTT membrane technologies. There are four LNG carriers using this technology on order.
- There have also been advancements with the Moss spherical cargo tank system, with both Kawasaki and Mitsubishi engineering elongated ‘sphere’ designs which can transport more LNG than a typical Moss-type LNG carrier without any increase in beam by using vertically stretched tanks that maintain the same tank diameter. The innovative Sayaendo and Sayaringo concepts developed and built by Mitsubishi Heavy Industries (MHI) feature four Moss tanks protected by a continuous cover integrated with the ship’s hull, with a design boil-off rate of 0.08%. A significant reduction in fuel consumption is also achieved through improvements in ship weight, as is a reduction of longitudinal wind force, with the use of the continuous tank cover.
- After a gap of more than 25 years, since two medium sized LNG carriers were delivered in 1993 to serve the Alaskan LNG project, four newbuild LNG carriers are under construction using the IHI-SPB prismatic independent type tank system. It is claimed that the new DFDE propelled 165,000m³ ships will reach the low BOR of 0.08%/day.

1.4.3 Ship cargo capacity

The transportation cost per unit load decreases with larger sizes; however, due consideration must be given to design concerns and potential compromised compatibility with receiving terminals as the vessel size increases.

In order to decrease the LNG transportation cost, it is effective to increase the quantity of cargo on each voyage. By increasing the cargo capacity via stretched tanks, new designs provide more capacity (up to around 180,000m³),
while maintaining compatibility with the existing LNG export/import terminals and meeting the new Panama Canal beam limits.

Larger vessels are more economical, because they allow fixed costs to be spread over larger volumes of cargos, which reduces overall costs and helps LNG trade grow. The cargo capacity of standard size LNG carriers has increased as operational experience has been gained and the need for economic efficiency has grown. “Standard” sized LNGCs grew in capacity from 125,000 to 150,000m³ between 1975 to 2005, while the average LNG storage capacity for a new build delivered during 2016 was around 168,000m³, compared to 153,000m³ for the global LNG fleet in 2015 (144,000m³ excluding Q-Flex & Q-Max tankers) and an examination of the LNG ship order book (as of 31December2017) reveals that more than 95% of all newbuild LNGCs on order have capacities between 170,000 and 180,000m³.

Although membrane containment systems have enabled Q-Flex ships with a capacity of 217,000m³ and Q-Max ships with a capacity of 266,000m³ to be built, carriers above around 180,000 cubic metres are, at present, too large to transit the Panama Canal (the current 49meter beam limit means that neither Q-Flex or Q-Max LNGCs are able to transit the Canal, although the beam limit may eventually be relaxed to 51.2meter, enabling Q-Flex ships to transit), nor are they able to deliver to all regasification terminals given their size. To date (except for one FSRU), only Qatar has ordered LNG carriers with capacities above 182,000m³.

2. Barriers to a liquid shipping market

2.1 Technical and logistical constraints

Ship size is a key point to be reviewed before delivering any cargo. As an example of constraint associated with ship size, some terminals cannot accommodate fully laden conventional vessels due for draft reasons. Q-Max and Q-Flex vessels cannot be accepted in some terminals, thus limiting the possibilities of diversions. Sixteen different ports were known to be capable of receiving Q-Max ships as of January 2017⁴. Of the 45 terminals that are reported to be limited to receiving conventional vessels, 20 are FSRUs. To this effect, a specific website has been designed to inform ship managers and terminal operators about the compatibility of vessels and terminals⁵.

Despite these physical constraints, some markets are utilizing vessels to design creative import solutions⁶. Jamaica imported its first LNG cargoes in 2016 through a series of ship-to-ship transfers from conventional LNG carriers to a floating storage unit stationed offshore, then to a lightering vessel set to deliver smaller volumes to an onshore regasification receiving center. Jamaica’s LNG imports highlight a potential trend in the LNG industry – that of smaller, immature markets joining the

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⁴ Source : IGU World LNG Report 2017
⁵ www.lngwebinfo.com
⁶ Source : IGU World LNG report 2017
global LNG market by utilizing idle existing infrastructure to develop small-scale projects relatively quickly.

Similarly, Malta became an LNG importer in January 2017 by utilizing an older tanker as a floating storage unit (FSU) and then sending LNG onshore to an onshore regasification facility.

In addition to ship size, canals can be major physical constraints negatively or positively affecting the fluidity of LNG trade.

Since 2016 and the addition of new locks, the Panama Canal has contributed to the development of new and potentially shorter trade routes. In 2014, only 8.6% of the LNG fleet was able to transit through Panama Canal, versus 91% of the fleet with the newly expanded canal. Provided there is no traffic congestion and that the level of tariffs is attractive enough, the new infrastructure adds to the liquidity of the shipping market. Time savings for a trip with the new Panama Canal compared to alternative routes are summarized below:

<table>
<thead>
<tr>
<th>Route</th>
<th>Distance round-trip</th>
<th>Days round-trip</th>
</tr>
</thead>
<tbody>
<tr>
<td>US Gulf to Tokyo via Panama Canal</td>
<td>18,528 nautical miles RT</td>
<td>46 days RT</td>
</tr>
<tr>
<td>US Gulf to Tokyo via Cape of Good Hope</td>
<td>32,054 nautical miles RT</td>
<td>74 days RT</td>
</tr>
<tr>
<td>US Gulf to Mejillones via Panama Canal</td>
<td>7,314 nautical miles RT</td>
<td>20 days RT</td>
</tr>
<tr>
<td>US Gulf to Mejillones via Cape Horn</td>
<td>19,368 nautical miles RT</td>
<td>45 days RT</td>
</tr>
</tbody>
</table>

However, it should be noted that transit capacity for LNG carriers in the Panama Canal needs to be shared with other vessel categories, which limit the available physical transit capacity for LNG carriers. In July 2017, the available transit capacity for LNG carriers was only one vessel in each direction. Due to the logistics involved, congestion may occur not only for physical reasons but also due to an inefficient booking process. In the first quarter of 2017, LNG accounted for 9% of Neo-Panamax transits but 23% of bookings.

2.2 Regulatory constraints

2.2.1. Ship Inspection Reports (SIRE) by oil majors

In some cases, the availability of LNG carriers may be hindered by regulatory requirements, especially given the willingness of oil majors to strengthen rules for
monitoring incidents which affect the environment. LNG carriers which call at a terminal which is a member of OCIMF (Oil Companies International Marine Forum) are requested to pass a SIRE evaluation and meet certain criteria. Ship managers are required to complete the SIRE evaluation every year.

2.2.2. Restrictions by port authorities

Despite the excellent safety track record of the industry, port authorities impose very severe restrictions for berthing of LNG carriers. Night berthing of LNG carriers in any port in Japan is prohibited, as in many other countries. (Similarly, no voyage at nighttime was allowed through the Panama Canal in 2017). Ship to ship bunkering for LNG carriers in any port in Japan is also prohibited.

LNG carriers are required to hire escorting boats when approaching from the pilot station to any berth in Japan for arrival, shifting from a berth to pilot station for departure. Also, LNG carriers are requested to hire a warning boat and warning buoy during cargo operation at any berth in Japan.

In addition, many countries, apply “cabotage” rules which limit domestic shipping to vessels whose flag is only for that country.

2.3 Commercial constraints

2.3.1. Destination clauses.

In a LNG Sale and Purchase Agreement (SPA), destination clauses designate a list of unloading terminals as destination ports of LNG cargoes. These clauses limit to different extents (sometimes absolutely) the buyer’s ability to designate different delivery locations, and are always present in Delivery Ex-Ship (DES) SPAs, and often seen in Free On Board (FOB) SPAs. However new contracts are being signed with no restrictions on shipping for FOB contracts and fewer restrictions on DES contracts.

In practice, these restrictions are limiting competition and preventing resale of LNG in the event that a buyer cannot take a contracted cargo.

Very recently, the Japanese Fair Trade Commission (JFTC) has called for removal of destination clauses in FOB contracts in new SPAs, and for review and relaxation in existing contracts.

2.3.2. Lack of standard Contracts

Another challenge is the lack of standardized contract terms for LNG shipping. Each Time Charter Party contract is a custom contract, extensively negotiated, clause by clause, between two parties. Accordingly, each contract uniquely specifies positioning, risks, costs, and liabilities to be borne by each of the parties. Moreover, there is usually no pre-defined way to operate the vessel, and it is usually done with a view of optimizing costs in the course of the voyage. Making an effort to standardize more contracts will improve liquidity and increase reliable and comparative price information.

2.3.3. Political barriers and commercial relationships between countries

Bans on particular countries or limitations on trade with particular countries can cause a trade disruption that could force cargos to be diverted elsewhere, it may disrupt
trade routes, and it may also force affected vessels to dock and refuel far afield. Any of those will alter LNG trading patterns, potentially increase tonne-miles demand and thus tighten the shipping market.

2.3.4. Operational constraint
Some producers do not allow ships to cool down at the facilities except if they are coming from dry dock. This creates a limitation in the availability of LNG shipping capacity for charter and could create an issue in chartering the vessel out if the timing does not work for various charterers.

2.4 Financial constraints
Spot charter rate levels are directly correlated with the number of LNG carriers which compete in the spot market. As a result, if the number of vessels competing in the spot market increases, spot charter rates should decrease.

Given this correlation and the high cost of LNG carrier newbuilds, most shipowners will seek to secure charters when possible, especially in times of low charter rates. Equally, owners will more easily raise funding to build new vessels if their investments can be underpinned by the security of time charters. In this context, the growth of the spot market raises difficulties with regard to the financing of new vessel construction, which is highly capital intensive.

Traditionally, banks have had a strong interest in funding LNG carrier construction, which is considered as less risky than other shipping sectors given the prominence of long-term charters in LNG and the level of risk borne by charterers. However, most banks today consider that LNG trade is not sufficiently liquid for them to treat LNG carriers in the same way as oil carriers or bulk carriers.

In order to reduce the risk associated with long-term repayment profiles, banks will thus favor mid or long-term charters, therefore reducing the number of spot vessels available and the overall liquidity of LNG shipping.

2.5 Human constraints
At the end of 2017, there were a total of 478 LNG carriers, and in 2018, an additional 63 carriers will be delivered, so we expect nearly 550 LNG carriers will be in operation by the end of 2018. This means that crew demand for LNG carriers shall increase, so obtaining well qualified crews is one of the crucial issues for ship managers or ship operators.

3. Recommendations to remove barriers to a liquid shipping market

3.1 Second hand market (Source: The four LNG Shipping Markets by Georgios H. Dretakis)

The purpose of this second hand market is to increase the efficiency of operators in providing shipping services by re-allocating ownership of vessels and does not affect the tonnage capacity offered in the market. The main participants are the shipowners.

The LNG second hand market is very marginal. The limited liquidity that the second-hand market offers arises from the restrictions on these LNG ships to participate in
several trades. Nowadays there is not any active second hand market, since companies prefer to charter newer vessels in order to avoid potential liability, even if they are substantially more economic.

A shortage of new build ships might induce a more liquid second hand market among existing ships pushing prices up for older ships and this market could be substantial.

3.2 Contractual tools to promote the development of the spot and short-term market

In order to enhance liquidity, adequate tools need to be developed in order to facilitate the employment of LNG vessels by many players. LNG tankers are typically chartered under time charters (i.e. a standard contract allowing the charterer to use a certain ship for a certain amount of time) If time charters may be appropriate for long-term chartering, the use of more flexible and standardized contracts specifically designed for spot and short-term trades could contribute to increase the liquidity of LNG shipping.

Indeed, one of the key concerns for charterers is the ability to accurately assess the cost of transporting LNG from one location to another. This may be especially true for trading houses, who aim to hedge their freight costs.

Several types of standard Contracts can be used to facilitate spot and short-term fixtures, among which are Contracts of Affreightment (COAs) or Voyage Charters.

- A Contract of Affreightment is an agreement between a shipowner and a shipper concerning the freight of a defined amount of cargo in which the shipowner chooses the ship to be used for the transaction.
- A Voyage Charter is an agreement for the transportation of cargo from port(s) of loading to port(s) of discharge. Payment is normally per ton of cargo, and the ship owner pays for bunker, port and canal charges etc.

In this context, BIMCO and GIIGNL have developed a standard Contract, LNGVOY7, a Voyage Charter designed to provide standardized terms and facilitate spot fixtures. In LNGVOY, four main issues inherent to LNG shipping have been addressed:

- a “boil-off” cap whereby both owner and charterer agree on a negotiated maximum quantity of boil-off over the voyage.
- LNG heel at the commencement and completion of the voyage
- Presentation: condition of the cargo tanks on arrival at the loading port is now covered. The costs involved can be handled adequately under a voyage charter as opposed to a time charter trip covering the three potential conditions:
  - cooled down and ready to load
  - warm under natural gas vapours
  - warm and inerted.

- Window of arrival at discharge port (given the inherent nature of the cargo, scheduling of arrival times at discharge carries great importance and delays can be very costly. As a result, most voyages have a specific delivery window and risks of delay and ensuing boil-off have been allocated.)

3.3 Optimization strategies

3.3.1. Pooling strategies (Source: LNG World Shipping)

Efficiency may be enhanced by more structure in the shipping market and promoting more pooling activity.

Golar LNG, GasLog and Dynagas, founded the first LNG-carrier pooling arrangement (called the ‘Cool Pool’), benefiting from the LNG shipping market recovery and the rising number of spot cargoes being booked worldwide. The pooling activity allows them to share the losses in a loose market, be more competitive in the market and optimize better the fleet. Chief among these are avoiding the costly repositioning of vessels and arranging forward fixtures up to a year ahead. In an arrangement similar to a contract of affreightment (COA), customers can book a certain number of days from Cool Pool over a year while offering the carrier first call on all the specified cargo.

In the year 2016, since the three shipowners launched their co-operative venture, around 300 spot LNG fixtures were concluded, up from 190 for the previous 12 months, of which Cool Pool secured some 90. The fleet now stands at 18 vessels (155-162,000 m3), with Golar and GasLog upping their contributions to 10 and five ships, respectively.

3.3.2. Backhauls

Backhauling is the transportation of LNG in the reverse direction to the main flow. This is a tool increasingly used to optimize the fleet for LNG ship ballast voyages.

By picking up volumes from a closer supply source and delivering those volumes en route to the original liquefaction source, the vessel is never unladen more than 50% of the time. This can be done by either a short-term leasing out of the vessel for the length of backhaul, or as a physical swap, which would entail at least partial payment in LNG or natural gas volumes elsewhere.

3.3.3. Swaps

The shipping market can also see greater optimization through geographical LNG swaps. These have the potential to reduce trading distances and smooth out scheduling issues if a vessel is unable to make it back in time to lift a cargo.

Inter-basin flows are positive news for shipping, but combined they present an opportunity for shippers to reduce transportation costs by swapping cargoes. For example, if an LNGC delivered a cargo from Qatar to Belgium and on the same date, another LNGC delivered a cargo from the US GOM to Pakistan, with both vessels transiting the Suez Canal in opposite directions, if both parties could have entered into an LNG swap, in theory they may have been able to achieve savings of approximately US$0.42/mmbtu per cargo (which equates to roughly US$1.5 million).
If parties could agree to a physical swap to serve each other’s closest buyer, not only would there be significant cost savings, but it would also free up some of the vessels involved to carry out other trades. In addition, if a swap platform could be created for sellers and buyers to be aware of potential swaps that could be done – although this will be a challenge.

Market participants can mutually benefit from coordinating short sub-lets and swaps to optimize their fleets.

3.4 Financing: what measures could be taken to lift the financial constraints associated with spot chartering?

In order for spot newbuilds to be financed, creditworthiness of shipowners and relationships with their banks are key. For spot vessels, corporate loans are the most likely solution. When structured as project finance, banks will require recourse to the owner via guarantees. In some instances, additional risk mitigation will be required. Owners may also need to raise financing via other means than via banks. Alternative means can include: resorting to export credit agencies to encourage bank involvement, private equity, stocks, bonds, master limited partnership (MLP) investors, or sale and leaseback transactions. In all cases, a greater risk will entail a higher cost of financing and in order for new investments in spot vessels to be viable, a fair allocation of risk between banks, shipowners and charterers should be encouraged.

4. Conclusion

The liquidity of LNG shipping is an essential condition of the liquidity of LNG markets but it is not sufficient on its own, as other components such as availability of supply are also critical for liquidity. The LNG shipping market is facing two fundamental uncertainties which have the potential to affect the development of liquidity:

a) How will LNG demand evolve across the various regions in the future?

b) What will be the share of spot and short-term trade?

Aside from these market dynamics, liquidity of shipping could be enhanced through various approaches. Among priority measures, a greater standardization of charter contracts could reduce chartering delays and contractual uncertainty. As a second step, innovative financing schemes and a fair allocation of risk between owners, banks and charterers must be found in order to allow the development of a more substantial spot fleet. Finally, physical optimization strategies may further develop, provided that all players can access sufficient market information and that no destination clauses prevent such trades.
Chapter 4 – Receiving Terminals & SS

1. Introduction
The availability of specific LNG import infrastructure plays a crucial role. No trades with physical delivery involved can be done if there is no receiving infrastructure in place.

There is a direct linkage between the LNG infrastructure and the number of market participants. So, if the liquidity as we define it in this paper is subject to the number of players involved in the business, then it is essential to understand the requirements for the infrastructure; being an ultimate instrument for the market access for the customers. Hence, to understand the potential of LNG for becoming a liquid commodity we will have to take a closer look at the characteristics and current trends of LNG receiving terminals.

Therefore, the following section examines the physical prerequisites for the liquidity of LNG from the viewpoint of infrastructure. We will look at different types of receiving terminals, applying various access regimes, and their contribution potential for the LNG liquidity. Another aspect of our analysis will be the role of NG trading platforms at and around the terminal infrastructure. Furthermore, we will look close at the role of the new businesses (such as small scale LNG applications) developing around the existing infrastructure, and their role in fostering LNG liquidity.

2. Regasification Terminals and their impact on the liquidity.
2.1 Types of LNG receiving terminals
Liquidity is enhanced by offering different kinds of LNG import terminals that can be adapted to the needs of the market.

- **Onshore LNG terminals** – are land-based facilities where LNG is unloaded from carriers to storage tanks located on a plot of land near the port. Next, the LNG undergoes the regasification process in an onshore plant and is transmitted into the gas system. Another form of onshore terminal is the Adriatic LNG terminal (installed offshore near Venice in Italy), which is a regasification facility located on gravity based structure (GBS) artificial island.

- **Floating LNG terminals** - this kind of terminal generally has lower starting capital costs and shorter time to market as compared to an onshore terminal, however they incur higher operating costs over the life of the terminal. In emerging markets, FSRUs are a good solution and are helping increase liquidity. FSRUs (floating, storage, re-gasification unit) are offshore storage and regasification terminals in the form of a floating vessel equipped with LNG storage and regasification infrastructure. Depending on local requirements there can be other types of vessels used, such as floating storage units (FSU) with onshore regasification facilities. Floating terminals have gained popularity over the past several years and nowadays the share of FSRUs accounts for 10% of the total installed receiving terminal capacity. FSRUs have become the most common pathway for new importers to enter the LNG market.
• **Small scale facilities:** Regasification facilities with a lower throughput capacity, in the range of 0.05-1.00MMtpa are typically classified as small scale LNG (SSLNG) terminals. Some major reasons for choosing a small scale terminal over a conventional size facility are as follows: firstly they are aimed at covering a rather small size market, potentially with a special demand profile. Secondly such terminals can be built over a shorter time period, often due to the modular nature and standardization of the components to build the small scale facility. It also requires fewer funds, hence affordable for smaller players with limited recourse to capital markets. However while the overall investment in such a facility is much lower, the relative per unit costs of small scale facilities are costlier. So the decisive factor of such an investment will have to be supported by other drivers than investment costs. For instance, it can be a good option for coastal countries where LNG offers a viable solution when the gas transport by pipeline cannot be developed economically. Small-scale receiving terminals are gaining momentum in the current markets as a result of cheaper LNG and the focus on LNG as environmentally friendlier fuel.

Small-scale terminals increase the number of players in the industry, and hence, increase the turnover of the LNG trades, although in bulked/fragmented quantities. It is fair to say, that the future of small scale facilities depends on market conditions and on the environmental regulations. These incentives need to be strong enough to enhance further expansion of small scale LNG.

2.2 **Services offered / Technical capabilities:**

Some receiving LNG terminals offer different services (in addition to regasification of the LNG, loading and unloading of LNG vessels and storage of LNG in tanks), such as truck loading, gassing-up and cooling down operations and bunkering.

With those services, LNG terminals provide flexibility in the market and increase competition between gas suppliers. But the role of an LNG terminal and the services varies from country to country depending on specific market characteristics, i.e. supply and demand characteristics, number of companies active in the market, availability of LNG import terminal capacity, pipeline infrastructures imports dependency, etc.

Moreover, there are different ways to offer those services: all services separately (unbundled approach) or the main services together, such as berthing of the LNG vessel, storage of LNG and regasification of the LNG and injection of natural gas into the transmission grid (bundled approach).

The easier, it is for companies to access different services irrespective of whether the service is bundled or unbundled the more liquidity could be enhanced.

One essential service which should be provided at every terminal is a boil-off gas (BOG) management. Some advanced terminals are equipped with BOG handling facilities in order to achieve zero gas losses from boil off during operations as well as during the period of very low or even zero regasification operational rate, hence, irrespective of send-out rate. LNG continuously evaporates at temperatures above its
boiling point generating BOG due to the infiltration of heat, volume displacement, and pressure variation during the storage and movement of LNG. All LNG regasification terminals must deal with boil-off gas (BOG) during operations. Improvements of revenue, energy efficiency, and the environment have driven operators to optimize their systems to include BOG recovery. Some of the options to handle BOG include:

- Routing the BOG to a recondenser unit, using the cold energy of LNG to liquefy the BOG under medium pressure (recondensers are typically large columns equipped with structured packing, although an innovative way to recondense BOG using its static mixing technology is available).
- Boosting the BOG to pipeline pressure using a high pressure compressor for directly sending to pipeline in order to provide less restriction on the terminal’s minimum send out requirements.
- Re-liquefying the BOG through refrigeration and returning it to the storage tanks.
- Reducing BOG occurrence by installing a pressure control valve and by doing so BOG can be managed in each tank separately at a different pressure.
- Improving insulation of cryogenic pipelines.

2.3 Commercial aspects

2.3.1. Accessibility

Open access to regasification terminals will increase liquidity by enabling new participants to be active in the LNG terminal and associated markets. There are two main ways of operating new LNG terminals: 1) a regulated approach with central planning of the needs along with regulation of requirements for new capacities 2) a market-oriented approach (exemptions), in which case the capacity holder remains fully responsible for his decisions. Depending on the approach, receiving LNG terminals can be subject to regulated third party access (rTPA) or can be exempted.

The choice to regulate or to exempt a receiving terminal from regulation depends on the characteristics of the associated gas market. The responsible national regulatory authority will pursue its own objectives or give priority to certain regulatory challenges.

a) rTPA

In case of a regulated terminal the utilization conditions and tariffs are set by a regulator. In general terms, rTPA tends to be a more transparent regime. It aims at equality of conditions and rules for all market players. For this reason, rTPA is a recommended regime for an immature LNG/gas market. However, the disadvantage of regulated regimes is that these are less adaptive to the evolving market needs. Hence, they might not be suitable for investments i.e. of a large scale and with higher risk expectation. Furthermore, unstable regulated regimes bear a higher level of risk for consumers.
For example, in the case of Japan, although most LNG terminals offer TPA access or at least negotiated TPA, in practice, no third party has effectively gained access to an LNG terminal in Japan although most of them offer TPA in theory.

b) nTPA

In contrast, if the terminal is exempted from regulation, the investor sells capacity directly to buyers which could increase liquidity if the investor or capacity holder is willing to sell spare capacity. At the same time the regulator has responsibility to analyze the clauses of exemption and to ensure that there is no harm for competition and conditions for terminal usage are transparent. Hence, exempted terminals are more flexible to adapt their services to market circumstances and set to foster competition if they choose to do so.

c) Number of players using the terminal services

Over the last couple of years some more new players have entered the LNG business. This marked an advent of the changes to the traditional LNG business models. In the past, players were committed to long-term contracts, with those long-term contracts backing the infrastructure investments. Today trading on the spot market has become more attractive. The amount of freely traded volumes has grown and more trading companies (such as Trafigura, Vitol, Gunvor, and Glencore) are increasingly involved in LNG trade and supply.

2.3.2. Availability of a trading platform at the terminal

Well-functioning trading platforms can stimulate further transformation of LNG into a liquid commodity. LNG pricing mechanisms still vary considerably across the world. Clearly observable is a tendency to move away from the traditional oil indexation and to redesign LNG contract schemes to allow more flexibility in commodity flows. Although LNG trading activity has been increasing constantly in the last years – mainly driven by the global financial institutions that have entered the business in the tight market phase to gain from generous spot margins – LNG remains predominantly a product that is traded over-the-counter (OTC) rather than on an exchange. For this reason, it is said that the LNG trading world is a ‘club’, where traders, producers and buyers know each other and know how and where to find the necessary information. It is so-called ‘pick-up-the-phone-and-call’ trading. The emergence of some new trading platforms or strengthening the positions of the existing ones could add flexibility and increase liquidity.

2.4 Small scale activities

A baseload liquefaction or regasification facility, or a small scale facility can represent a source of SSLNG. By means of SSLNG supply a wider range of end users can be served. The main groups of customers are wholesale players either at ex-terminal or DES basis as well as consumers in bunkering, onshore transportation and off-grid with satellite regasification units.

SSLNG applications have been expanding globally in recent years albeit not as fast as previously anticipated. Economic, environmental and political reasons have driven the
spread of SSLNG consumption differently in various regions of the world. With the evolving of new, more flexible LNG trade forms SSLNG has turned out to become an attractive alternative sales channel. Moreover SSLNG has triggered customization of services and products allowing new entrants to penetrate some niche segments, which has led to a growing market competition. For these reasons, the EU has launched different programs for the development of SSLNG (including CEF funds, TENT-T programs and Horizon 2020 programs).

Described below are the main SSLNG handling and distribution forms as well as corresponding services provided and their impact on market liquidity.

The following figure presents general commercial architecture of SSLNG services and some key elements of this structure will be elaborated below.

**LNG Services**

![LNG Services Diagram](image)

1. **FOB delivery**
   - Buyer is responsible for transportation, access to regas and entry capacity
2. **DES delivery**
   - Seller is responsible for transportation, buyer – for access to regas and entry capacity
3. **Delivery at flange**
   - Seller is responsible for transportation, access to regas and entry capacity
4. **LNG for trucks**
   - Buyer is responsible for trucks, seller delivers LNG at flange
5. **LNG for bunkers**
   - Seller is responsible for barges, seller delivers LNG at flange

**Figure 1- SSLNG services**

2.4.1. **Break bulk**

Break-bulk services split up large-scale LNG shipments into smaller parcels enabling the distribution of SSLNG to dedicated small scale receiving or/and storage facilities. The demand for LNG break-bulk services is expected to grow in the years ahead. It is driven by general market evolution, stronger activities of LNG-trading intermediaries and steadily increasing LNG volume contracted on destination-free terms.

Whereas break-bulking has already become available at the Gate terminal, it is also under development in Zeebrugge and at the National Grid LNG terminal on the Isle of Grain. The major liquid spots in the North Western Europe are clearly transforming into one-stop shops where customers can regasify, store, reload, parcel out and dispatch LNG in required amounts. In the Baltic region such a pattern is followed by the FSRU in Klaipeda, which has introduced a “virtual storage” mechanism, to enable traders to serve emerging demand both in the regional gas and LNG break-bulk markets.
In another part of the world Singapore is paving the way for building up a regional SSLNG market. By offering break-bulk services it enables an expansion of LNG consumption first of all in Indonesia and the Philippines. Malaysia and Thailand would also potentially benefit from the introduction of such projects. Existing large regasification facilities in Southeast Asia can be easily retrofitted for break-bulk facilities.

It is worth mentioning that not in every market does break-bulk or dedicated SSLNG terminals make economic sense at this moment. On one hand, due to existing installed capacity such as in Spain, where seven import plants are located; on the other hand, because of still insufficient demand.

Offshore break-bulk (by ship-to-ship transfer) could potentially also boost liquidity in different parts of the world, especially if there would be an increase of the number of supply or bunker vessels, and older vessels that serve as FSUs, to unlock new market potential.

### 2.4.2 SSLNG Carriers

To move small LNG parcels in order to get closer to a final consumer one needs to employ small LNG carriers. Small scale LNG barges and ships with cargo-carrying capacities of anything between of 1,000m³-30,000m³ are being constructed and the number of such vessels is constantly increasing. Two types of vessels are available: with membrane or IMO type C tanks. The new generation of ships is designed to be able to unload cargoes partially across different terminals, so that part-loaded voyages can be undertaken without exposure to the dangers of sloshing.

Today there is still a relatively small fleet of SSLNG carriers; therefore the market is not liquid enough. Mostly these are ship owners who are building an LNG carrier for their own use. As they have few alternatives for using the ship, it is generally expected that a charter is ready for entering a long term commitment with the ship owner. Some ship brokers are offering a short-term vessel usage on the basis of contract.

The flexible nature of SSLNG makes a multi-drop model or milk run pattern also quite attractive, which can help increase liquidity. A SSLNG vessel could undertake a number of part-cargo unloads across multiple small scale receiving units within a region, moving LNG around according to local needs. It helps to share shipping costs between more locations and to utilize available carrier capacity better.

### 2.4.3 Truck loading

Supply by truck is the main and most developed option for SSLNG distribution today. Building truck loading facilities has become the first step of terminal operators in upgrading their infrastructure. LNG trucking is the most affordable transportation mode for small volumes, as a service provider needs only a cryogenic tank trailer and prime mover. Usually a truck can transport between 16 to 22 tonnes of LNG with a single trip. Due to its flexibility it can be easily...
redirected to any supply point. However restricted availability of commodity sources (as is the case in the Balkan region in Europe) makes it sometimes necessary to cover a distance of up to 2,000 km, significantly increasing total sourcing costs of LNG. Nevertheless at this stage of market development LNG trucking seems to be sufficient to cover the emerging demand. It allows carrying out truck-to-ship bunkering operations, supplying remote regasification units and LNG fueling stations. Typically distribution by truck means a higher delivery frequency.

As for consumers changing to LNG the security of supply is one of the most sensitive issues, as an unlimited and easy access to a loading point is of tremendous importance to any SSLNG provider. Truck loading facilities operators should bear in mind that a more flexible and less complicated regime of nominating and loading can boost the utilization rate of their facility.

Another improvement of loading services is a provision of infrastructure for the safe handling of cryogenic ISO containers, which could be a bigger part of intermodal logistics of SSLNG. Initially carried by trucks and loaded at the terminal they can be simply transferred to a waterway or railway carrier to be brought further to a consumption place. A growth of interest in ISO containers and correspondingly an increasing number of manufactures have been observed in recent years. The parcel size of one ISO container is similar to the carrying capacity of one truck, and simultaneous transportation of several containers by ship or rail car provides a multiplying effect.

2.4.4 Railroad distribution

The further expansion of ISO containers would give an impetus to rail transport. Railroad distribution is operating in Japan and is being actively developed in the USA, initially started in Alaska and Florida. India is also implementing such transportation. In Europe railroad distribution has not been available yet, however pilot projects are currently under study in the Netherlands, Spain and the UK.

3. Conclusions

The evolution of the liquidity on LNG markets will depend on different factors, many of them related to LNG infrastructure, such as, technical characteristics, capabilities, services offered and commercial issues, among others:

- **Types of receiving terminals:** Nowadays there are different kinds of LNG terminals (onshore and offshore) that can be adapted to the needs of the market, along with the emergence of small scale LNG terminals.

  **LNG terminals offering different services:** Due to economic, environmental and political reasons new services such as bunkering and truck loading, as well as supplying new consumers not connected to the gas network, are emerging where they have not traditionally had a presence. Thanks to these services, LNG
Terminals provide security of supply and diversification, flexibility to the system and increased competition between suppliers.

- **Trading platforms:** Broader use of well-functioning trading platforms can stimulate further transformation of LNG into a liquid commodity.

- **Access regime:** Access to regasification terminals is not always open to third parties, and they can be subject to rTPA or can be exempted. However from the point of view of liquidity, the more participants that are active at a terminal, the more liquidity can be increased, so it is important to implement open access at each LNG terminal.

- Additional, the liquidity on a natural gas hub can affect the usage of a LNG terminal, as the greater the liquidity of hub is, the greater the utilization of the terminal.

For this reason, to obtain global, flexible and liquid market, LNG terminals have a vital role and operators should constantly optimize utilization at their facilities and foster investments in improvement to allow for both large and small scale activities at terminals and create enough liquidity to stimulate the creation of a global market.

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Chapter 5 – Market/Supply

1. Introduction

The energy industry has dramatically changed over the past half-decade. Especially, on the supply side, where a surge in natural gas production in the United States has changed the landscape – a country that was expected to become one of the largest importers of natural gas has become a net exporter, with liquefied natural gas ("LNG") exports playing an important role. US LNG projects are standing out among others in that most of the contracts are more flexible in both destination and volume when compared to more conventional suppliers. At the same time, Australia has substantially increased their production and will continue to grow. This large growth in supply and increasing flexibility is having an impact on volume of LNG in the market as a whole and in particular the spot market – looking to make LNG more available on a spot basis over the next few years. In addition, from the perspective of the demand side, new trading houses with higher risk tolerance are providing market expansion to previously disconnected markets. This chapter sheds light on these changes in the LNG industry.

2. Assessment of LNG market overall

2.1. Historical LNG Market Trends

Vertically integrated chains, observed commonly in many LNG transactions, has been one of the most prominent factors deterring the increase in LNG market liquidity. On one hand, being a vertically integrated chain is effective in reducing risks related to investment in developing new natural gas projects. On the other hand however, it serves as a barrier to entry and liquidity as such an operation is generally only feasible with large scale investment based on long term sale and purchase contracts providing less flexibility and liquidity in the supply chain.

In traditionally LNG projects, development, production, liquefaction and transportation (DES-basis) have been carried out by International Oil Companies (IOCs), National Oil Companies (NOCs) and Trading Houses. With these players, electricity and gas utility companies entered into sale and purchase contracts and have typically been in charge of transportation (when the contract is on a FOB-basis), LNG import infrastructure and gas distribution. In short, by IOCs, NOCs and Trading Houses being the usual sellers and utility companies (power and gas) of the importing countries being the buyers in long term contracts lasting for around 20 years, vertically integrated chains have in the past limited the ability for new players to enter the LNG market.

2.2. Present LNG Market Trends

Recently however, changes in the LNG value chain have been observed. Firstly, utility companies of importing countries have started demanding a variety of options from the LNG suppliers. It should be noted that in countries where market liberalization has progressed, more flexible shorter term contracts have resulted. Secondly, LNG suppliers have been willing to accept shorter terms consistent with market evolution. Furthermore, for liquefaction plants that have been in operation for over 20 years, initial costs of such projects are fully or nearly recovered, giving the suppliers room to accept shorter contract durations. For example, projects such as North West Shelf and

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Malaysia LNG, have already signed renewal contracts with shorter durations. Such changes in both the supply and demand side are spurring change in the traditional vertically integrated LNG chain; “portfolio contracts” becoming increasingly common is one good example reflecting such change (see figure below regarding logistics of various types of LNG contracts).

Source: Roland Berger analysis based on expert interviews

2.3. Date of short-term/Spot % growth

Traditionally, sanctioning an LNG project required most of the planned production of LNG to be sold on long term contracts. However, during the cost reduction movement in the 1990’s, there were some cases where the final investment decision was made while a portion of the liquefaction capacity remained unsold. Furthermore, it has become possible for some leading players to take positions in both the supply and demand side so that their LNG can be produced and sold at various places, being optimized based on the price trends (such mechanism is incorporated into the aforementioned “portfolio contract”).

On top of such changes in business models, with the United States no longer requiring large scale LNG imports as a result of the shale gas revolution, the number of spot and short term based transactions has increased. Consequently, the average contract duration and volumes are decreasing.

The chart shows the evolution of LNG contract term length and volume between 2008 and 2016.
While the following chart highlights the growth of LNG volume of contracts less than 4 years in term between 2000 and 2016.

Source: GIIGNL, Annual Reports "The LNG Industry" 2005 to 2017
Shifting the focus of discussion to spot pricing, a change is observed here as well.

Source: FGE-LNG Online Data System

On a side note, details of spot deals are usually confidential between the involved parties and therefore it is difficult to grasp correctly the state of the spot market. Recently however (from 2009 to be specific), media companies such as Platts, ICIS Heren, RIM Intelligence, Argus and Energy Intelligence started to publish estimated spot LNG prices based on interviews from sellers, buyers and any other related parties, and it is becoming easier to obtain a more specific picture of the market. However it should be noted that the accuracy and transparency of such estimates are limited.

2.4. Tradable volume

The global demand increased from 101 MTPA in 2000 to 264 MTPA in 2016, with an increase in demand volume and in the number of buyers and importing countries. From 2010, the number of import countries increased greatly from 23 to 39 by 2016. The increase is due to a variety of reasons but there have been two key factors over the past couple of years – the introduction of floating regasification has allowed new less credit-worthy countries to start-up LNG imports faster and with less upfront capital required.
3. Analysis of HHI on liquidity

3.1. What is HHI index?

3.1.1. Methodology
One of the key criteria for a developed market is the number of companies trading in this market/hub. This important indicator is set to reflect the level of participation in the market. Market liquidity increases with active trading and a higher number of participants, i.e. buyers and sellers. Active trading improve liquidity, tightens bid/ask spreads and reduces opportunities for market manipulation. Therefore, the Herfindahl-Hirschman Index (HHI) methodology (which reflects market concentration) was used to assess the liquidity of LNG and the level of participation in the LNG market and at the concentration of the buyer/seller power. Specifically, to analyze the development of the LNG market we investigated how HHI for exporters and importers of LNG have changed over time. Also, total nameplate capacity and the number of companies acting as sellers or buyers were considered as indicators of liquidity of LNG.

The data in the HHI related figures in this section has been sourced from GIIGNL Annual Reports.

3.1.2. High level assumptions
- Trains running at significantly low utilization rate have been excluded.
- For the sake of simplicity, ramp-up period is not taken into consideration (production is expected to reach its plateau within the start-up year).

3.2. Assessment

3.2.1. Analysis of seller side

The total nameplate capacity of LNG plants has become larger over time; it surpassed 300 million ton per year in 2016, and is still on a stable upward trend.

![Nameplate capacity total (excluding suspended trains) in mtpa](chart)

Source: GIIGNL, Annual Reports "The LNG Industry 2005 to 2017"

8 "European Traded Gas Hubs" by Oxford Energy Institute, May 2017, Page 3.
9 "European Traded Gas Hubs" by Oxford Energy Institute, May 2017, Page 3.
Robust growth in LNG production can be observed from the increase in the number of countries acting as seller. As the charts below show, the number of exporting countries has increased continuously, and it reached 19 as of 2017.

The number of the countries

Source: GIIGNL, Annual Reports "The LNG Industry" 2005 to 2017

At the same time, market concentration has also decreased. As the charts below illustrate, the number of countries and companies selling LNG has increased to a level which can be regarded as “moderately concentrated” (0.15 < HHI < 0.25) or “unconcentrated” (HHI < 0.15). This healthy trend has been supported by the growth in LNG production overall.

HHI by country

HHI by company (LT Seller)

[Source: GIIGNL, Annual Reports "The LNG Industry" 2005 to 2017]
3.2.2. Analysis of buyer side

Keeping in step with the change in the seller’s side, the buyer base is also becoming more diverse. As the chart below illustrates, the number of companies acting as buyers also has progressively trended upward. One of the enablers of this positive change is advances in technologies such as the introduction of adding regasification onto LNG ships (FSRUs). FSRUs can be implemented more quickly than onshore facilities and the upfront capital investment required is less intensive than those of land based facilities, especially when existing LNG vessels are converted into FSRUs. These features are a good fit with emerging countries seeking LNG and thus FSRUs have contributed to boost demand all over the world.

[Source: GIIGNL, Annual Reports "The LNG Industry" 2005 to 2017]

Thanks to the growth in buyers, the market concentration has also become lower. As the below chart of the HHI by buyer companies illustrates, HHI has reached to the level where market concentration can be regarded as “unconcentrated” (HHI < 0.15). This healthy trend is expected to persist as more new buyers and countries enter the LNG market over the coming years.
3. Enhancing LNG market liquidity

3.1. Expectation for growth of short-term/spot out to 2020

It is expected that the volume of spot deals plus short-term contracts will increase up to more than 100 MTPA by 2020, accounting for above 30% of all transactions of LNG.

Source: GIIGNL, Annual Reports "The LNG Industry" 2005 to 2017, Roland Berger analysis based on expert interviews
3.2. LNG market outlook

From a traded volume of 264 mtpa in 2016, the global LNG supply outlook in 2030 is forecast by Wood Mackenzie to increase to 400mtpa, based on liquefaction trains which are under construction today, with the possibility of delivering up to 600mtpa of LNG by 2030, should the market conditions develop in favour of LNG and support investment decisions for proposed projects.

Source: Wood Mackenzie
The following figure identifies the regional growth in LNG liquefaction capacity from 2016 to 2022.

**Comparison of liquefaction capacity of LNG in major regions (MTPA)**

Source: International Gas Union, World LNG Report 2017

The strongest driving force to the increase in demand lies in Asia, which is predicted to account for 70% of the increase in global demand from 2016 to 2030. Many countries in Asia are typically far from natural gas sources and isolated from nearby countries by sea, thereby restricting the means of procuring natural gas to importation of LNG. The second largest contributor to the demand increase is expected in Europe, accounting for above 20%. Reasons include a demand increase due to decline in indigenous production of natural gas within Europe, and an expected demand boost from the power sector, with the plans for a gradual exit from coal fired plants from 2022 onwards. In the midterm period, European regasification capacity is seen as a sink for LNG, especially for US LNG, and for Asian buyers looking to optimize their procurement contracts using access to the liquid European Gas market.
3.3. LNG future trade potential

Trade flows of LNG are expanding throughout the world. Compared with natural gas imported via pipeline, LNG is expected to grow at a faster rate making up an increasing portion of imported gas around the world. This trend is perceived as a business opportunity not only by the traditional IOCs, NOCs, and Trading Houses but also by those who are generally considered ‘Commodity Traders’, increasing the number of players in this market. On top of that, Japanese utility companies that traditionally focused on importing LNG are now participating in the trading business to increase operational flexibility. As such, even more players are expected to join the LNG trading market, leading to increasing market liquidity.

4. Conclusion

This chapter considered the development of the LNG market from the perspective of buyers and sellers. Over the past five years there has been an increase in the number of the participants and in the volume of spot and short-term transactions. To keep the momentum towards market liquidity progressing, the number of participants on both sides needs to grow continuously and adequately in order to prevent further concentration and a biased distortion.

However, in the long run this current positive trend might face a head wind due to industry amalgamations (i.e. TEPCO/Chubu [JERA], Shell/Repsol LNG, Shell/BG, and Total/Engie LNG). The stagnant commodity price has put a burden on investment decisions for new LNG production, which will lead to a cyclical tightening of the supply in five years from now, thus, slowing down the growth of the market participants from the producer side. On the other hand, observing current trends in the commodity markets, it is safe to assume that the gas/LNG demand will continue to grow, hence leading to an even more diverse and versatile buyer’s side. Hence, it remains to be seen whether growth of supply can keep up with that of demand in the longer term in order to keep the market in balance and, in turn, to diminish the LNG market cyclicality.

5. References
- IGU 2017 World LNG Report, April 2017
- Survey on LNG Trades(Chapter 4 Ensuring of fair competition in LNG trades), by The Japan Fair Trade Commissions, June 2017

- Survey on Natural Gas and LNG Markets, by Ministry of Economy, Trade and Industry in Japan, March 2013
Chapter 6 – SPA’s

1. Introduction

The landscape for LNG sales has significantly changed over the last 10 years. The LNG market has expanded as new producers and consumers have entered the scene. Developments, changes and advances in the commercial, regulatory and technological environment have affected each leg of the LNG value chain. Market participants drive and react to these developments, changes and advances. Consequently, the terms and conditions of sales of LNG have changed.

Mature gas markets have expanded their existing LNG import infrastructure and, in some cases, implemented programs to deregulate the downstream market. New markets have adopted technological innovations (e.g., floating regasification) to develop regasification capacity and gain access to the LNG market. There are expanding uses of LNG (e.g., ship bunkering). Regulators in mature markets are utilizing the regulatory regime and national laws to promote flexibility in contracting.

The development of conventional and unconventional gas reserves via liquefaction projects in Australia, coupled with the shale gas revolution in the United States, has changed the shape of the LNG industry. In less than a decade, the United States has changed from being a sometime LNG net importer to becoming a major exporter of LNG. The transformation of the United States from a net importer to a net exporter has resulted in more LNG supply and increased competition.

At the same time, many long-term legacy contracts began to expire in accordance with their terms. This transition freed the suppliers and buyers from the terms and conditions of those legacy contracts.

In addition, new participants entered the LNG market to take full advantage of the changing business environment. A handful of global trading companies with large customer portfolios and access to LNG production and/or regasification infrastructure can maximize arbitrage opportunities between various LNG markets.

Concurrently with the above, a spot market developed for LNG cargos. For the buyer, the spot market allowed it to cope with seasonal requirements through short-term and spot purchases. The producer could sell uncommitted LNG volumes. Reports from the Intercontinental Exchange (ICE) show that Japan/Korea Marker (JKM) swaps cleared through that financial market have continued a strong level of growth, exceeding 4 million tons for the first six months of 2017. For 2018, market analysts anticipate a much stronger growth both in the supply side volumes and in the number of swaps, as new projects are expected to come on stream or to ramp up, notably in Australia and the United States.

LNG is becoming more and more commoditized as a result of each of the above.

In addition to the LNG market specific factors above, the use and demand for competing fuels (including wind and solar for power generation), the flexibility of power generation and gas storage has had a major impact on the commercial landscape for LNG.
The terms and conditions of an LNG Sale and Purchase Agreement ("SPA") evolve in response to seller and buyer requirements and demands. Historically, these requirements have included:

- The seller’s requirement for long-term contracts to support base-load production and the development of capital-intensive infrastructure.
- The buyer’s requirement for security of supply.

SPA terms and conditions continually evolve to reflect an expansion of LNG production capacity, weaker global LNG demand, portfolio sales, and deregulation of downstream markets (e.g., third-party infrastructure access and competitive pricing). Of course, political, economic and social conditions will change over time – usually unpredictably. If the LNG market is to have greater liquidity, the commercial structures and terms and conditions of the sale will need to be robust and balanced in order to moderate the likely market fluctuations and, at times, dislocations.

This chapter addresses how the terms and conditions of an SPA may enhance the liquidity of LNG and speculates on potential future developments in contracting for the sale and purchase of LNG.

Before doing so, however, it is useful to establish the meaning of the term “liquidity” and identify how the industry may measure “liquidity”. This chapter defines liquidity as the ability to buy and sell LNG without a significant price disruption and without significant transaction costs. Metrics to measure “liquidity” in the LNG market may include:

- **Volume** – Represented by the number and size of LNG transactions.
- **Costs** – Represented by lower transaction costs for LNG transactions.
- **Time** – Represented by the frequency of transactions within a defined period of time and over different time horizons.
- **Diversity in active counterparties** – Represented by the number of counterparties and diversity in counterparties (oil companies, traders, financial institutions and others).

To be clear, LNG liquidity is not the same as contract flexibility. Flexibility may be one criteria to measure LNG liquidity. However, on its own, flexibility does not result in enhanced LNG liquidity if one or more of the other characteristics of LNG liquidity are not present.

### 2. Deregulation and the Spreading of LNG Supply Chain Risk

A deregulated environment for the production, transportation, regasification and downstream sale of LNG will materially enhance LNG liquidity. While such deregulation may result in temporary dislocations in certain markets, deregulation will encourage new players to invest in the LNG supply chain. These new players may contribute capital, new technologies, and/or commercial innovations.
Deregulation will also create an environment for market participants to design and test new tools to manage LNG supply chain risks. These new tools may accelerate the reallocation of risks associated with the LNG supply chain.

The US LNG export revolution is perhaps the most visible example of how a deregulated environment may enhance LNG liquidity. This occurred in large part because of a competitive domestic natural gas market, more flexible regulation in respect of LNG exports and the risk capital introduced by new actors in the LNG supply chain.

3. Commercial

3.1. Collaborative LNG Purchases

Collaborative LNG purchases by regionally diverse buyer-consortia or consortia of buyers with small LNG demand may enhance LNG liquidity. Collaborative LNG purchases may create a platform for greater and more active counterparty diversity. For example, buyers with different seasonal demand profiles may jointly purchase LNG under one contract. In other cases, a buyer with more regular demand may collaborate with another buyer having flexible demand or access to gas storage capacity. From the seller’s perspective, a joint or collaborative purchase by buyers in different markets may effectively open new markets for LNG. Further, joint or collaborative purchases among buyers with different credit ratings may act as an indirect credit enhancement for the weaker credit. While buyer-consortia in a single geographic area may result in a larger demand center, such geographically focused buyer-consortia may deter liquidity if collaboration creates a concentration of demand in a consolidated market.

3.2. Volume

Smaller volume contracts may enhance LNG liquidity by stimulating more regular contracting. Smaller volumes may also enable buyers to more flexibly respond to market signals in their downstream markets. There will need to be further technological advances to justify smaller volume contracts. There are already technical advances that support LNG storage, break-bulk service, bunkering vessels, and trans-shipment. Open 3rd party access to regasification capacity may create more competition and demand in the downstream market, thus stimulating LNG liquidity.

Similarly, if the buyer has enhanced rights to reduce its annual volume commitments under long-term contracts through higher downward flexibility, this may enhance the attractiveness of LNG as a commodity vis-à-vis competing fuels. The optionality associated with downward flexibility may be priced or unpriced depending on the level of flexibility. Such enhance buyer flexibility may, by freeing up committed volumes, increase the volume of LNG trades. Of course, enhanced buyer downward flexibility may undermine LNG liquidity if the SPAs do not support a steady revenue stream and the development of new liquefaction capacity.
3.3. Price

Traditionally, LNG prices were linked to crude oil as sellers and buyers viewed LNG as a substitute fuel for crude oil. Over time, as natural gas market hubs developed in the United States and Europe, the hub index formed the basis of LNG prices in those locations. Multiple LNG indices may converge to a single LNG index.

More likely, however, the variety in demand centers, market regulation and supply/demand imbalances will likely cause LNG prices to follow the pathways created by other commodities. For example, if LNG followed coal, there may be competition among a variety of price indices – pricing based on destination, pricing based on source, and/or pricing differentials based on quality specification. For example, there may be opportunities for LNG pricing differentials on a “rich LNG” or “lean LNG” basis.

Price transparency represented by an LNG index functions as an indicator of enhanced LNG liquidity. Price transparency will evolve more rapidly when combined with broader deregulation, more active and diverse counterparties and greater traded volumes.

More regular price reviews within defined parameters may enhance LNG liquidity. Sellers and buyers may be willing to make longer term commitments if the price adjusts on a defined basis. To the extent that the seller and buyer transact by reference to a transparent index, price reviews may not be as necessary.

3.4. Contract Term

Historically, the SPA had multi-year term (commonly 20 to 25 years) to give investors enough time to recover their investment in infrastructure and to secure profits. A shorter term SPA may facilitate buyer demand as the buyer may be more willing to commit to an LNG purchase if it is not exposed to long-term risk. The increase in buyer demand may enhance LNG liquidity by encouraging production. Further, a shorter term will likely facilitate an increase in the number of LNG transactions (volume) and encourage diversity in the length of contract terms (time). From a financing perspective, a shorter term SPA will shift the long-term market risk to the seller. Thus, shorter term SPAs may result in reduced liquidity if sellers are unwilling to take the long-term market risk.

A contractually defined process for SPA roll-over may further enhance liquidity by expediting the roll-over of the shorter term SPAs. This may contribute to reduced transaction costs.

3.5. Flexibility

3.5.1. Buyer destination flexibility.

Destination clauses in the SPAs of FOB contracts restrict buyers ability to freely re-sell the volumes on the market. However, a commodity’s liquidity is greatly helped if it can be freely traded among counterparts. Hence, a destination clause is an inherent hurdle for the market liquidity. To enhance liquidity the SPA may either identify a greater number of primary receiving terminals or even totally
remove destination clauses. The buyer may choose to deliver cargos to any one of the primary receiving terminals in response to market demands and/or to take advantage of arbitrage opportunities, thus actively participating in the market, in which case buyers would also act as re-sellers. Such an increased flexibility in SPAs may enhance liquidity as the buyer may be willing to assume more volume or term risk in return for destination flexibility. Further, buyer destination flexibility may create an opportunity for diversity in active counterparties and an increase in the regularity of LNG sales.

For example, the removal of the destination clauses has been ruled by the Japan Fair Trade Commission, with the commission suggesting the review of competition-restraining clauses in contracts and refraining from business practices which might lead to restrictions of resales. The market has responded to this appeal and recently this has been implemented in some new Japanese contracts.

Buyer destination flexibility will enhance LNG liquidity when combined with lower transaction costs and greater diversity in active counterparties.

3.5.2. Seller call-back rights.

As a corollary to buyer destination flexibility and buyer downward flexibility, the SPA may include seller call-back rights (with or without a fee). The seller’s call-back rights may be permanent or on a cargo basis. The seller may choose to exercise its call back rights and sell the cargos to other markets in response to market demands. The increased flexibility for the seller in SPAs may enhance liquidity as the seller may be better positioned (compared to a buyer) to respond to broader market demands. As with buyer destination flexibility, seller call-back rights will enhance LNG liquidity when combined with lower transaction costs and greater diversity in active counterparties.

3.5.3. Seller/Buyer diversion rights and profit sharing.

The SPA may provide seller and/or buyer diversion rights with a profit share mechanism. Reciprocal diversion rights with a profit share will enhance LNG liquidity in that the seller and the buyer will have incentives to divert the LNG in response to market demands. Reciprocal diversion rights may be on the basis of “reasonable consent” to address the seller or buyer’s desire for security in supply. Further, reciprocal diversion rights with profit share will fully enhance LNG liquidity if applied in DES or FOB contracts. As with buyer destination flexibility and seller call-back rights, seller/buyer diversion rights will enhance LNG liquidity when combined with lower transaction costs and greater diversity in active counterparties.

3.5.4. Trading of LNG Contracts

Parties ability to trade LNG short-term contracts may enhance LNG liquidity. This will require standardize terms for short-term tradable contracts, identifiable and standardized specifications, and may be further supported by blockchain technology.
3.6. Modified Take-or-Pay

The traditional SPA included a take-or-pay clause that calculated the take-or-pay payment utilizing the contract price for LNG. A modified take-or-pay calculation may encourage new production and new demand. Instead of calculating the take-or-pay payment utilizing the contract price, the SPA may have a take-or-pay calculation based on an agreed liquefaction cost. Alternatively, the SPA may adopt a damages regime whereby the buyer pays the seller the loss (if any) that the seller incurred by selling the LNG to a 3rd party buyer. A modified take-or-pay regime may enhance LNG liquidity if the modified regime lowers overall transaction costs for the buyer.

3.7. Standardized Terms

The standardization of certain SPA terms and conditions may enhance LNG liquidity by reducing transaction costs. Standardized clauses may address force majeure, termination rights, governing law, dispute resolution, seller’s liability for off-specification LNG and seller’s shortfall, tax indemnification and the indemnity regime.

Market participants in the United States have utilized the standardized North American Energy Standards Board Base Contract for the Sale and Purchase of Natural Gas for many years. However, the United States natural gas market is significantly more homogenous and liquid than the international LNG market.

For the LNG industry to adopt standardized terms, market participants must have material economic incentives to adopt standardized terms. And then, the substantial majority of market participants in an internationally trade commodity must agree to adopt a common set of terms for those terms to have widespread use.

4. Operational

4.1. Compatibility

Simpler and more standardized technical standards, regulations and vetting procedures will facilitate the commoditization of LNG shipping and result in increased LNG liquidity. A wide disparity in the compatibility standards and vetting process for LNG vessels will undermine any flexibility built in the SPA if diversions are constrained by LNG vessel and regasification terminal compatibility.

4.2. Quality Measurement

Standardization of LNG measurement standards and platforms may result in increased LNG liquidity through greater efficiency and reduced costs.

4.3. Quality Standardization

Transparent and standardized classes of LNG quality within regions (e.g. one for “lean” LNG market, another for “rich” LNG market) may enhance the portability of LNG contracts. This increased portability will improve LNG liquidity as the LNG contracts and underlying product may be more easily traded.
4.4. Development of Annual Delivery Program

An electronic auction system for loading slots/unloading slots and the development of an annual delivery program may enhance LNG liquidity and reduce transaction costs. Third party access to regasification capacity and send-out capacity will cause a system to develop that is more sensitive to demand requirements. LNG liquidity is likely to be constrained by the limitations in transportation and the need to manage LNG delivery slots. As a consequence, buyers/sellers may be unable to transact LNG on a “day-ahead” or similar basis.

5. Other

5.1. Cool-Down as a “Service”

The development of cool-down stations as an independent, paid-for service available to the market (more than simply long-term or premium customers) will enhance LNG liquidity. Independent companies may establish cool-down services at different geographic locations to service the global LNG fleet.

5.2. Collaborative LNG Sales

There may be opportunities for LNG producers and financial institutions to provide a more flexible LNG product that includes a physical and derivative transaction.

5.3. Adoption of Worldscale for LNG

The adoption of Worldscale (a unified system for establishing payment of freight) may enhance LNG liquidity through standardization of LNG freight costs. The adoption of Worldscale may result in lower transaction costs, thus enhancing LNG liquidity.

5.4. Wider Adoption of Contracts of Affreightment

A wider use of contracts of affreightment may encourage new participants to invest in the transportation leg of the LNG value chain and result in higher transportation efficiencies and lower transaction costs.

5.5. Blockchain and Smart Contracts

Blockchain technology may increase LNG liquidity by improving LNG value chain efficiency and decreasing overall transaction costs. Sellers and buyers may utilize blockchain technology in all or part of LNG sales contracting to:

- Enhance data sharing among LNG producers, transporters and buyers to better manage supply disruptions and demand imbalances.
- Encourage development of an open and transparent hub-price.
- Create an opportunity for dynamic pricing.
- Promote LNG trade finance.
- Simplify and accelerate the process and paperwork associated with loading, unloading, measurement and testing, invoicing and payment.
- Accelerate uniform standards and procedures and integrate artificial intelligence and machine learning in the contracting cycle.

Over time, participants in the LNG value chain may execute LNG trades based on electronic “smart contracts”. The “smart contract” may permit integrated measurement and testing, invoicing and payment.

6. Conclusion

How do enhanced LNG Sale and Purchase Agreements promote LNG liquidity? This can achieve this by incorporating flexibility and creativity and implementing standardization.

- Greater flexibility will increase frequency and the number of transacted volumes, reduce transaction costs and, potentially, expand the number and type of counterparties active in the LNG market. LNG sale and purchase agreements may demonstrate flexibility by incorporating buyer/seller diversion rights, destination flexibility, seller claw-back rights, shorter contract terms and shorter contract terms.

- Creativity in LNG contracting and commercial structures will increase frequency and the number of transacted volumes, reduce transaction costs and expand the number and type of counterparties active in the LNG market. Examples of creativity include collaborative LNG purchases, use of Worldscale or similar indices for freight calculations, separate contractual “services”, utilizing of innovative pricing models and the use of blockchain or similar technologies.

- Finally, standardization may enhance LNG liquidity by reducing transaction costs. Contractual clauses ripe for standardization include force majeure, termination rights, governing law, dispute resolution, seller’s liability for off-specification LNG and seller’s shortfall, tax indemnification and the indemnity regime.

The flexibility, standardization and creativity will be supported and encouraged by a properly regulated environment for the full LNG value chain.
Chapter 7 – Quality

1. Introduction

Liquidity describes the degree to which an asset can be quickly bought or sold in the market without affecting the asset's price, thus requiring the quality of that asset to be consistent.

LNG quality is important, as any gas which does not conform to the agreed specifications in the sale and purchase agreement is regarded as “off-specification” (off-spec) or “off-quality”. Therefore, LNG supplies need not only to be compatible with quality specifications in the receiving markets but also interchangeable with other sources of LNG and pipeline gas.

Composition of LNG is a function of the composition of the natural gas source and the treatment at the liquefaction facility. The composition of LNG changes throughout its lifecycle due to preferential vaporisation of components during shipping, transfer and storage.

LNG is not as fungible a commodity as it appears to be and the increasing globalisation of LNG trade has highlighted the mismatches that can occur between LNG quality and the differing importation specifications for the end users. The harmonization of LNG quality and gas interchangeability has been an increasingly important item on the agenda of energy companies and regulators. It is a key driver to facilitate tradability and liquidity as well as safety and operability for domestic, commercial and industrial applications.

Consumer countries have varying degrees of flexibility for LNG quality and the heating values of distributed natural gas with which the regasified LNG must be compatible varies by regions and/or end customers:

- Asia (Japan, Korea, Taiwan – distributed gas typically has an HHV that is higher than 1,090 BTU/SCF (40.6MJ/m3))
- U.K. and the U.S.- distributed gas typically has an HHV that is less than 1,065 BTU/SCF (39.7MJ/m3),
- Continental Europe - the acceptable HHV range is quite wide: 990 to 1,160 BTU/SCF (36.9 to 43.2MJ/m3).
National gas quality specifications define gas quality limits to protect the integrity of the gas network and ensure that gas supplied to domestic users will combust safely. They specify the gas allowed in a network and are included in commercial gas trading contracts for energy accounting, and to ensure that the gas purchased is suitable for the network.

In general, gas quality standards were based on the historic gas supplies received by a country or even by region for some countries.

Some countries like Belgium and France have invested in flexible burners where jets can be easily replaced or adjusted in the field. Others, like The Netherlands and Germany have opted for blending different gases during transportation.

Note that within Asia, while especially City Gas companies in Japan and Korea traditionally prefer rich gas and have gas-burning appliances designed for high heating values, while China and India have more flexibility with LNG quality.

On one hand, there is a distinct trend for average LNG quality to become leaner, in other words to have a lower calorific value. This includes the increased flows of the LNG from new US, Australian (derived from coal bed methane [CBM] - called Coal Seam Gas [CSG] in Australia) and Russian Yamal export facilities, which are all of lean quality. On the other hand, the LNG facilities in Qatar have been segregated with the flexibility to produce LNG in both lean and rich qualities, and hence can adjust their quality to meet the needs of the market.

The impact of the different qualities of gas on the performance of domestic appliances has been studied by numerous organisations and bodies around the world. The general objective of these tests is to assess the impact of a wider range of GCV and Wobbe...
Index on the safety, operation and efficiency of domestic appliances. This is in preparation for either change to region gas specifications that are envisaged due to a change in fuel supply, e.g. pipeline gas to LNG or harmonisation efforts, such as the proposed introduction of the EASEE-gas specification across Europe.

For a detailed coverage of quality matters refer to the 2011 IGU/BP “Guidebook to Gas Interchangeability and Gas Quality” and the 2006 report by IGU Programme Committee Study Group D1 “LNG Quality”.

One of the perceived challenges to LNG’s liquidity has been the growth of “lean” and “very lean” LNG supply from new LNG export facilities in the USA and Australia using unconventional gas as feed to produce low heating value LNG.

In the following chapter, we investigate if the quality of the LNG is a real impediment to the liquidity of the LNG market.

2. LNG from unconventional gases

Strong global demand for LNG has meant that many operators in the USA and in Australia have developed and are developing projects based on unconventional feedstock which has “lean” quality with high methane content and low NGLs.

These new supplies of LNG mean more competition and supply diversity, however there has been the question as to whether the low heating value of this LNG restricts the markets into which this “lean” LNG can be sold.

When initially put to the market about 10 years ago, the low heating value of the “lean” LNGs to be produced by the new Australian (which use coal seam gas from Australia’s east coast as feedstock) and American LNG facilities (which use shale gas as feedstock), were believed to have questionable desirability to some Far East LNG buyers and users, thus reducing the liquidity of LNG in those markets.

For example, critics of east-coast Australian CBM projects said that the CBM industry in Australia would stall because buyers of LNG, such as Japan and Korea, would not accept the lower calorific value of gas converted from CBM. However, in the conditions of the tighter market these “lean” LNGs have shown that their low heating value has not been an impediment to the liquidity of LNG. Given the market dynamics this might no longer be the case in the future.

LNG is traded based on heating value (e.g. US$/mmbtu and similar units). In the Japanese City gas market (for example) imported LNG requires some level of calorific value enhancement before introducing the gas into the pipelines. In the last decade, the gap between the LPG and LNG price on the heating value basis has been gradually closing. Buyers argued that the additional costs associated with blending or spiking lean LNG justify discounts on the LNG price, while sellers maintained that the leaner quality is already factored into the price. But this situation can change in the future.
2.1. LNG exports from the US gas network

The LNG export projects in the U.S. source their gas from the transmission grid, meaning that it will have been processed to meet the lean gas quality standards that prevail there.

In the USA, these LNG export facilities (including the Sabine Pass, Corpus Christi, Freeport, Cove Point, Cameron and Elba Island plants) source their feed gas from the US pipeline network, thus the feed gas is of pipeline quality, which is generally lean due to the fact, that most the NGLs having been removed (to be marketed separately) prior to injection in the pipeline.

Since NGLs in the USA have their own markets, the choice to add NGLs to LNG will depend upon its availability and upon the relative prices of ethane, propane and butane, and the heating value their addition would add to LNG. Some proposed export terminals, such as those on the US East Coast, may not have readily available source of NGLs. On the importer’s side, if higher Btu gas is required to meet quality specifications, it may be more economical to blend lean LNG with higher Btu LNG supplies rather than go through the expense of purchasing ethane at the prevailing prices at the LNG liquefaction terminal.

2.2. LNG from CBM

CBM is methane-rich natural gas which is found in deposits of coal. The main constituent of CBM is methane, accompanied by carbon dioxide and some nitrogen, plus traces of ethane. Other customary ‘natural gas’ components such as propane, butane and heavier hydrocarbons, condensate liquids and hydrogen sulphide, are entirely absent.

The relative proportions of methane and carbon dioxide can be quite variable from region to region, but commercially attractive CBM resources generally have a methane content in excess of 95mol%. The lean nature of CSG due to the absence of any significant quantities of hydrocarbon compounds heavier than ethane means that CBM produces an LNG with a lower heating value (LHV) which is likely to be close to or beneath the minimum value normally specified by LNG consumers.

Since most of the carbon dioxide and nitrogen is removed during the liquefaction process the resulting product is almost purely methane.

3. Gas market in Japan

3.1. City Gas Companies

The equipment used by Japanese City Gas consumers is adjusted for a narrow gas quality range so as to run with the highest possible thermal efficiency. Any divergence can result in non-optimal combustion, with less-than-ideal results.

Even LNG based on conventional natural gas does not meet the calorific value benchmark of 45–46MJ/m³ required for City Gas supplies in Japan and LPG is added for the purpose of energy content adjustment. If the gas companies make greater use
of lean LNG, it would be expected that there will be increased consumption of LPG for the purpose of boosting the heating value.

Majority of the LNG procured by Japan’s City Gas companies has a calorific value in the range of 40–43MJ/m³, whereas by contrast, LNGs produced from unconventional natural gases have a calorific value in the range of 37–38MJ/m³.

Typically, increasing the heating value of regasified LNG is achieved by injecting LPG (propane or butane) into the gas. As of today, Japanese companies can manage the lean LNG with the available LPG tank capacity and given the current price level of the LPG. Again, it needs be recognized that this situation may change in the future.

When LPG prices have been higher than LNG prices and to lower feedstock costs, while securing the supply at the same time, some City Gas suppliers decided to decrease the rate of LPG use for increasing the calorific value by reducing the standard calorific value of its gas supplied.

3.2. Power Utilities

Gas quality and composition variations have a direct impact on combustion characteristics and may result in incorrect operation of the system or a detrimental effect on the product. The magnitude of the impact depends on the application and the burner (and control) system. There may be the following impacts:

- Unstable combustion.
- Higher pollutant emissions.
- Lower efficiency.
- Ignition problems.
- Thermo-acoustic problems.

However, Japanese power utilities have fewer issues with lean gas than gas companies do. However, to increase utilization of the lean gas it is still necessary to expand LNG tank capacity. For example, in 2013 TEPCO started work at its Futtsu LNG import terminal, with the intention to build another two LNG tanks to secure flexibility in operations of the terminal with a view to expanding its handling volumes of low heating value (lean) LNG.

4. Conclusion

To date large volumes of LNG produced from unconventional gases from the USA and Australia have been contracted into the global market. This is clear evidence that the market can absorb different qualities of LNG and has not been overly impacted by the introduction of these lean LNGs.

As to the established LNG markets, the evidence has shown that buyers have a certain degree of flexibility as how to manage different qualities of LNG. E.g. lean gas can be blended or “spiked” with LPG to produce the required heating values, which is why lean quality of LNG have not stopped companies from buying US and Australian LNG, although blending to meet LNG quality specifications, especially for a high volume of
LNG, is still a cost consideration for the buyers. New markets where the LNG/gas market is at the early stage of the developments may need to adapt to absorb different qualities of LNG.

Looking at the LNG quality from the perspective of the producers, it is fair to assume that with an exception US exports (with feedgas of pipeline quality) and LNG of CBM origin, the quality of the LNG will remain predominantly a commercial decision of the exporting companies since the NG liquids can be segregated and marketed separately. Hence, producers who feed their LNG export facilities with rich gas can adapt to the market needs of the customers in the future and produce either quality of LNG.

All in all, the different qualities of the LNG do not seem to pose a significant impediment for the tradability of LNG as fungible liquid commodity.
### Appendix

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