LNG MARKETS IN TRANSITION: THE GREAT RECONFIGURATION[1]

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ABSTRACT

The paper will analyze the challenges posed by the present business environment to the LNG industry as of 2016 and explore potential ways forward in terms of pricing and long-term contracts. Substantial amounts of LNG supply will reach the market by 2020 that may well exceed Asia's appetite for LNG, which had relied mostly on increasing demand from China, India and Southeast Asia, presenting uncertainties in terms of growth due to price sensitivity. The flexibility of some new supplies, notably from the United States, means that many companies may be left with large amounts of surplus LNG. In this context, Europe is widely seen as the residual market where additional volume could be sold but its absorption capacity is likely to be tested by resistance from pipeline suppliers, especially Russia. Could this trigger another shift in LNG business with sellers of either existing supplies having to renegotiate or new projects moving ahead without the support of long-term contracts?

[1] This paper previews the conclusions of a new book to be published later in 2016: LNG markets in transition, the great reconfiguration.

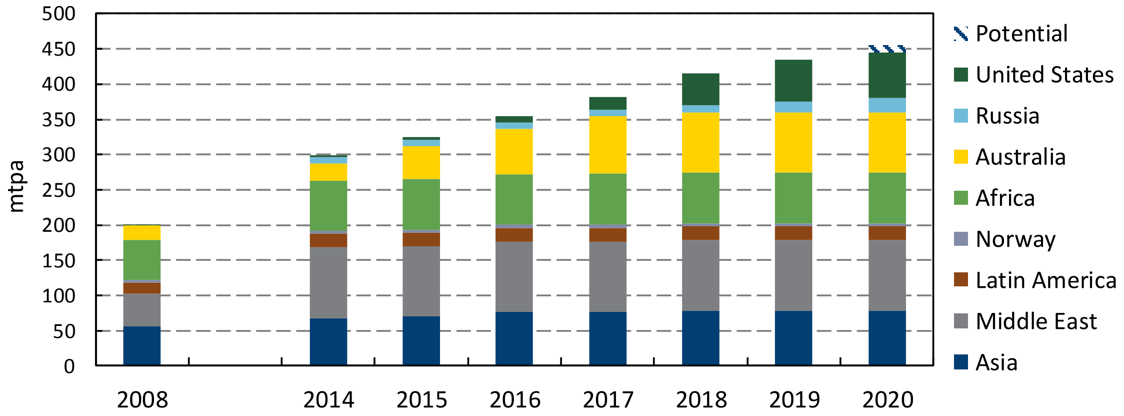
INTRODUCTION

2016 sees the LNG industry on the edge of a cliff. However, it is an open question whether it stands at the bottom ready to climb up in an orderly way or at the top and about to fall in a tailspin. The sector has embarked on such a vast expansion that it is impossible to see how it could emerge unchanged five years from now. The question is not just one of supply and demand, but also of whether the LNG industry's pricing and contractual frameworks will be fundamentally reconfigured.

Until 2014, the gas industry was looking at the new wave of LNG supply set to hit markets through 2020 as the indispensable tool for greater gas penetration in the energy mix, notably in Asia. That sentiment has changed as of 2016: Final Investment Decisions (FIDs) taken during the period 2009-15 will lead to a `wave of LNG' coming on line between 2015 and 2020 (150 mtpa) unprecedented in absolute terms. It will have far-reaching implications for global gas markets, which may be quite different from what was originally expected. These new deliveries are remarkable not only in size, but also for their origin. About 40 percent of new LNG export capacity will originate from the US, which only 10 years ago was predicted to become a bigger LNG importer than Japan. Investors in US LNG have tended to move like a herd, based on the behaviour of a first bold mover (Cheniere), but questions remain as to how much US LNG will really be exported over the long term.

Faced with this new volume of LNG, the gas industry's concerns have swung back to demand (or lack thereof). Asia has always been regarded as a bottomless pit, but now seems set to confound expectations. In 2015, LNG purchases dropped in the three largest LNG importers (Japan, Korea and China). There is also a growing anxiety that the rest of the world could start looking like Europe, where gas is squeezed by renewable energy and coal in the power sector.

Figure 1 LNG capacity under construction – 2015-20



Source: KAPSARC.

Pricing and costs are at the centre of a fierce debate. From 2011 through 2014, LNG prices were above $15/MMBtu in key importing Asian markets, making new LNG capacity seem like a profitable investment. This opportunity attracted the large quantities of LNG capacity that are under construction as we write. China crystallized this appetite for LNG investment, even though analysts failed to agree when forecasting its LNG needs. All gas industry players forecast a growing role for natural gas, portraying it as the fuel of choice. And yet in most parts of the world this 'inevitable' rise of natural gas is colliding with reality: gas is a high-cost energy resource trapped between cheap coal and policy-supported renewables.[2] The affordability of gas supplies will therefore be a key factor as to whether 'gas demand blues' continues or consumption rebounds. In particular, Asia is not ready to accept additional expensive LNG, even if the only alternative is 'dirty' coal. By 2020, the number of LNG importing countries is likely to reach about 40, with most new importers expected to have wholesale gas prices lower than $7/MMBtu. Investors, however, were counting on higher prices to guarantee that their new LNG plants would be economical. This likely price squeeze creates a strong imperative to keep costs under control in order for the LNG industry to continue to prosper.

Absorbing this new LNG supply will affect trade-flow patterns amid competition with alternative gas supply channels and other fuels but also pricing mechanisms, which are currently dominated by oil indexation. Oil indexation is under attack with US LNG selling at Henry Hub-indexed prices (plus costs). LNG suppliers have been pressured to adopt different pricing mechanisms and provide more flexibility. However, they also face high costs and are reluctant to abandon a business model in which they have confidence. While Asian and European spot prices have come closer during 2015, a complete globalization is still an elusive prospect in the absence of a global gas price.

An important untouched element remains in the LNG business: long-term contracts. Conventional wisdom is that LNG export plants must be supported by long-term contracts covering most of their capacity due to high capital costs. Current market conditions and the increasing amount of gas that is likely to be traded on a short-term basis because of oversupply may challenge the future of long-term contracts as they stand today.

PRESSURES BUILDING TO A CHANGE

Looking at the next five years, many factors point to a change in the way the LNG market operates. Individually, these factors would not trigger massive changes, but together, they could create a great reconfiguration of the LNG business.

Walking into a durable state of oversupply?

The LNG market has been in a state of oversupply since late 2014. The new export capacity of 150 mtpa, due on line over 2015-20, barring any unexpected event, is likely to result in a 'boom and bust cycle'. Even if a few suppliers stop production, such as that done in Egypt and Yemen, it does little to change the impression of massive oversupply in the coming years. Against that backdrop, views on future demand differ widely. Based on various LNG demand estimates, LNG trade will grow to 360-420 mtpa by 2020, a 120-180 mtpa increase from 2014 levels at 240 mtpa. Lower demand estimates suggest an oversupply situation to remain until at least 2020 and some expect it to last until 2025.

Most of the additional LNG supply is expected to be absorbed by China, other non-OECD Asian countries as well as Europe. However, in many Asian countries, notably Korea, Taiwan, Vietnam, Malaysia, Philippines, and Indonesia, substantial coal-fired capacity is under construction, which could reduce the volume of LNG supplied for power-generation in these nations. In Europe, LNG is facing competition from cheaper coal for electricity generation as well as alternative supply sources, notably Russian pipeline gas creating the potential of a price war between Russian pipeline gas and US LNG. There is also some evidence that buyers in Japan and China may be over-contracted in the period to 2020.

Meanwhile, about 1,000 mtpa of additional LNG capacity is currently proposed. The majority will be located in North America, as well as in Eastern Africa, Russia and Australia. This capacity is

[2] KAPSARC, Natural Gas: Entering the new Dark Age?

now looking at a post-2020 start, which means an FID over 2016-18 at the earliest. But weak demand in Asia, low oil and LNG spot prices since late 2014 and buyers' need for more flexible contract terms pose challenging conditions for FIDs to be taken. LNG projects currently proposed are likely to be deferred as sponsors wait for better times amid sky-rocketing capital costs.

The rise of spot and short-term LNG to 2014

Spot and short-term LNG (contracts of less than four years) rose to 29 percent in 2014 from 5.4 percent in 2000. As total LNG trade has also expanded, spot and short-term volumes have grown almost 10-fold to 67 mtpa from 5.6 mtpa. In 2000, these contracts were spread equally among all importing regions: Europe, the United States and Asia, while in 2014 the overwhelming majority went to Asia (74 percent) and the Americas (18 percent), especially Latin America. Contracts of less than four years represent a small share of total LNG trade, representing 5 percent in 2014 (16.5 mtpa), while spot contributes about 62 mtpa. The growth of short-term trade is important because it will determine the future relevance of spot-indexed prices and buyer's need for long-term contractual LNG volumes.

A supply view

The flexibility that spot and short-term LNG trade provides is partly due to LNG suppliers. Spot cargoes can consist either of 1) uncommitted or 'spare' LNG liquefaction capacity; 2) ramp-up volumes at the beginning of a liquefaction project; 3) volumes initially committed to markets but then released and redirected and 4) portfolio LNG.

The amount of LNG uncommitted/spare capacity was assumed to be about 9-14 mtpa over 2000-02, originating mostly from Africa and the Middle East. Looking at the delta between LNG exports and long-term LNG contracts (as of 2014), the total volume of uncontracted LNG is about 10 mtpa (mostly from Algeria, Abu Dhabi, Australia, Malaysia and Russia) (Table 1). Qatar has to be considered separately as the sum of all its contracts reported active in 2014 (101 mtpa) is clearly above its liquefaction capacity of 77 mtpa.

Table 1 The origins of spot cargoes: Analysis of contracts

	Free capacity	Exports - contracts	Redirecting from initial market	Aggregators with contracts
Algeria	17.83	2.05	US (3.2 mtpa)	ENI, Engie, Iberdrola
Angola	NA	0	US (5.2 mtpa)	Chevron
Egypt	0.25	0	US (4.3-5.1 mtpa)	BG, BP, Engie, Shell, Gas Natural
E. Guinea	0.3	0	US (3.4 mtpa)	BG
Nigeria	2.5	0	US (4-8.3mtpa)	ENI, Engie, Iberdrola, Shell, Total, Gas Natural
Norway	0	0	US (1.75 mtpa)	Engie, Iberdrola, Statoil, Total
Abu Dhabi	1.1	1.38		
Qatar	NA	NA	US (> 15 mtpa)	ConocoPhilips, ENI, ExxonMobil, Shell, Total
Oman	2	0		Union Fenosa
Yemen	0	0	US (4.55 mtpa)	Engie, Total
Australia	2.85	2.6		
Brunei	1.9	0.92		Shell
Malaysia	0.8	1.43		
Indonesia	12.59	0.07	Mexico (3.7 mtpa)	
Russia	0.5	1.48	Mexico (1.6 mtpa)	Gazprom, Shell
Peru	0.5	0.08	Mexico (3.95 mtpa)	Shell
Trinidad	0	0	US (9 mtpa)	BG, BP, Engie, Shell, Gas Natural
US	0.4	0.25		ConocoPhilips
PNG	NA	NA		ExxonMobil

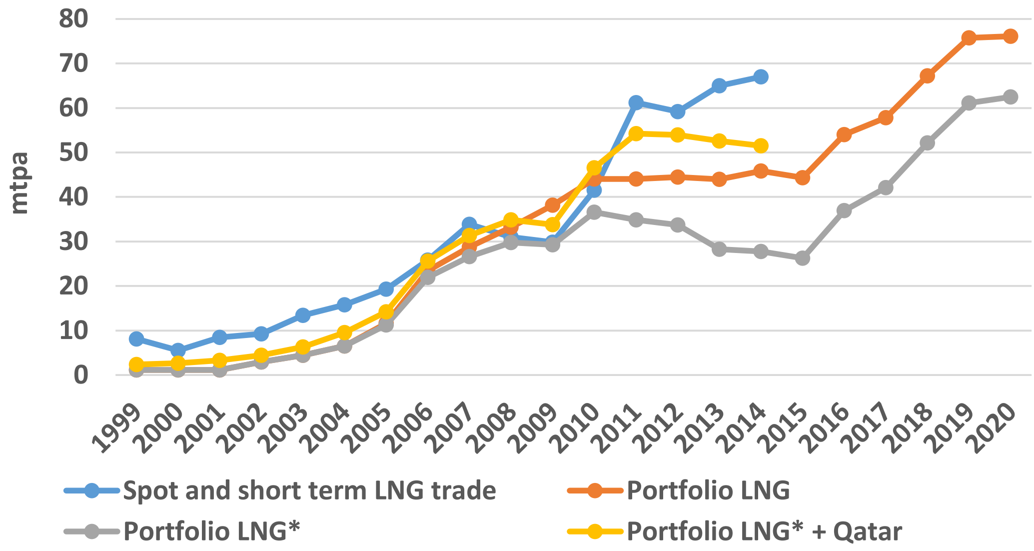
Note: spare capacity is calculated as the difference between nominal capacity of the LNG plants and long-term contracts in force in 2014. Exports – contracts based on 2014 data; negative values have been set to 0. Quantities redirected from the initial market refer to contracted quantities reported in 2008 (before the US shale gas revolution).

Ramp-up volumes are usually a short-term phenomenon, thus boosting the spot market periodically when contractual buyers are unable to take the supply. A recent example is volumes from PNG LNG in 2014 as the plant rapidly boosted capacity to design rates.

Volumes initially committed to markets but then released and redirected was initially even thinner, as cargo re-direction was strictly prohibited under the majority of long-term contracts, with the exception of a few that sought arbitrage between destinations. However, the termination of final destination clauses in Europe and supply/demand shocks have boosted LNG flexibility. In particular, flexibility drove the increase in re-exports, especially from Europe, which represented about 6 mtpa in 2014.

Contracts reported as portfolio LNG have increased to 46 mtpa by 2014[3]. About 90 percent of portfolio LNG is in the hands of aggregators[4]. They use arbitration strategies such that they would purposely have different LNG regasification terminals available to send supplies to the most favourable destination. This happened simultaneously with vertical integration and strategic partnerships, such as those of ExxonMobil and Qatar Petroleum, which have LNG assets ranging from Qatar to the UK and the US.[5] In the same way, shipping capacity and regasification capacity at the US Lake Charles and UK Dragon terminals support BG's trading activity. However, this portfolio LNG is also sometimes resold through secondary agreements making it, in principle, no longer available for spot trading.

Figure 2 Portfolio LNG as a source of spot LNG



Source: GIIGNL, author's analysis. From 2015 onwards, the grey line reflects no portfolio trade from Yemen and Egypt.

Comparing the evolution of contracts reported as 'portfolio LNG' (orange line) with spot and short-term LNG trade (blue line) could be misleading due to several factors: secondary sales to end-users, delayed starts of LNG plants, beginning of LNG contracts during the course of a year and the role of Qatar. The grey line includes the effects of secondary sales (those with portfolio as country of origin) and the delays and shortages, notably in Egypt, Nigeria and Indonesia. The role

[3] While using the term portfolio LNG, we have considered the volumes designed as such ('portfolio') by GIIGNL.
[4] The following companies are considered as aggregators: BP, BG, ENI, Enel/Endesa, Engie, ExxonMobil, Gas Natural, Gazprom, Iberdrola, Pavilion, Shell, and Total
[5] Ruster, S. Changing contract structures in the international LNG markets – an empirical analysis.

of Qatar will be analyzed later, as it presents little portfolio LNG, despite a high share of spot and short-term trading (25 mtpa in 2014). The yellow line includes the spot trade from Qatar; the curve has therefore a relatively similar pattern to the blue line, with the exception of the past few years, highlighting (among other things) an increase in LNG re-exports. Looking forward, volumes of portfolio LNG are expected to grow strongly. One factor that may dampen the strong growth will be for this LNG supply to be sold by the aggregators on medium and long-term contracts through secondary sales.

To summarize, the 67 mpta of spot and short-term LNG trade in 2014 can be split into around 10 mpta of uncontracted LNG, 25 mpta of LNG from Qatar, 28 mtpa of portfolio LNG and 6 mtpa of contracted LNG re-exported.

The market's evolution

While developments from the supply side have largely contributed to the rise of spot and short-term LNG, this has also been supported by significant changes in the market. The following factors have increased the development of spot LNG trade:

- Jump in LNG import infrastructure to 753 mtpa in 2014 from 353 mtpa in 1990, while liquefaction capacity rose to 305 mtpa from 118 mtpa.
- A change in the nature of buyers from government monopoly or utilities in OECD countries to include smaller players, independent power producers and traders seeking to profit from arbitrage opportunities. Meanwhile, established incumbents had to change their business models, as their market share was no longer guaranteed and stable markets saw greater volatility in gas demand.
- The impact of liberalization especially in Europe. Improved third-party access (TPA) and the end of final destination clauses were crucial to making Europe a more flexible market, while the development of liquid hubs enabled LNG to be delivered at spot prices.

Pressure for increased flexibility

Two elements could create the perfect storm for the LNG industry: uncertainties around the future growth of natural gas (and therefore LNG) demand and the doubts created by liberalization processes in Asia. The industry is increasingly worried that Asia may have missed its Golden Age of Gas. The slowdown in the Chinese economy and the restart of a few Japanese nuclear power plants are in contradiction with projections of continued high Asian LNG demand. Chinese, Japanese and Korean LNG imports were down in 2015, prompting suppliers to redirect LNG to Europe and to new importers such as Egypt, Pakistan and Jordan. Europe has now turned from being the market of last resort, receiving only leftovers from Asia, to absorbing all surplus LNG. Examples of Asian buyers feeling awash with more contracted gas supplies than they can absorb are numerous. CNOOC sold cargoes from Australia's Queensland Curtis LNG to BP and BG in mid-2015. Sinopec no longer seems keen to take its 7.6 mtpa of contracted LNG from Australia's APLNG[6]. In mid-2015, PetroChina requested Qatargas to skew deliveries under its 3 mtpa long-term contract towards the peak demand winter period[7]. Although this does not change the nature of the long-term contract, it is a major concession in terms of flexibility. Meanwhile, Petronet LNG has renegotiated the price of its 25-year long-term contract with Rasgas after India took only two-thirds of the contract volume in 2015, while their downward quantity tolerance (DQT) is only around 10 percent[8].

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[6] http://www.smh.com.au/business/energy/origin-energys-aplng-project-faces-headache-as-sinopec-said-unable-to-take-gas-20150622-ghuy5i.html

[7] http://in.reuters.com/article/2015/08/26/china-qatar-lng-renegotiation-idINL5N10Y0MC20150826

[8] OIES, Gas pricing reform in India: Implications for the Indian gas landscape

Regarding Japan, the IEA assumes a constant demand at about 100 bcm (74 mtpa) until 2040, while Japan's Ministry of Economy, Trade and Industry (METI) announced in 2015 that LNG imports would drop to 62 mtpa by 2030, assuming a significant restart of nuclear, which may be quite ambitious.[9] Contracted LNG supply will peak by 2017 at 90 mtpa and decline progressively to 35 mtpa by 2030. Based on the previous forecasts, Japanese LNG demand would be covered until 2020 and potentially longer if companies become comfortable relying on the spot market.

Korea offers a very different profile, as contracted supply is relatively flat at 32-35 mtpa until 2024, when contracted LNG are expected to drop abruptly. The Ministry of Trade, Industry and Energy announced late December 2015 that gas demand will decline to 34.65 mtpa in 2029.[10] Korea's gas-fired plants face competition from increasing nuclear and coal-fired capacity. Korea may be happy to keep a diminished level of contracted supply given the 9 percent demand decline in 2015 and the new long-term expectations. In addition, large seasonal variations require the country to resort to spot cargoes to cover winter demand, which has already made Korea an important player on LNG spot markets.

China's gas demand growth has slowed down to 2.5 percent over the first nine months of 2015[11] while LNG supply dropped in the face of the competition from alternative pipeline supplies from Central Asia and domestic output. The IEA expects demand to reach 315 bcm by 2020 and 483 bcm by 2030, implying import needs to increase from 143 bcm to 223 bcm over the same period. Meanwhile, CNPC scenarios show gas demand ranging from 269 to 360 bcm by 2020, highlighting considerable uncertainty for LNG imports, which would also depend on assumptions on production and pipeline supplies.[12]

Adding to this gloomy demand picture, Japanese buyers – both gas and power companies – will feel increased pressure once the residential power market is liberalized in April 2016, followed by the citygas sector in 2017. Under this process retail electricity and gas tariff regulation will be abolished, meaning that passing on fuel costs to retail rates will no longer be possible.[13] Liberalization of the gas market also includes a TPA scheme, even though some market players openly question its usefulness due to the fragmented nature of the Japanese market. Uncertainties brought by the liberalization will impact companies' appetite for extension of existing contracts. There are also signs that the mindset of Japanese buyers is moving away from the concept that long-term contracts bring security of supply to a mixed contractual approach that enable buyers to react to market changes.

Failure to liberalize the Korean gas market has effectively left KOGAS in charge. However, the government seems uncomfortable with the KOGAS monopoly, making it difficult for KOGAS to commit to additional long-term contracts (for example the government did not approve additional long-term Australian contracts in 2011). Meanwhile, China is considering spinning off its pipeline and storage infrastructure into a separate company with the aim of providing access to the market to new entrants. It remains to be seen how this will affect LNG imports. The NOCs, notably CNOOC (the largest holder of regasification capacity in China), are resisting giving access to new entrants.

Asian buyers are asking LNG suppliers for increased flexibility as a means to manage these uncertainties and lower-than-expected demand, and for the abolition of destination clauses, which

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[9] http://www.icis.com/resources/news/2015/09/16/9924240/japan-lng-imports-to-drop-to-62mtpa-by-2030-meti/

[10] LNG Intelligence, 30 December 2015.

[11] https://www.ief.org/_resources/files/events/iac-meeting---cnpc/cnpc-presentation.pdf

[12] http://www.bloomberg.com/news/articles/2015-09-30/china-gas-demand-forecast-cut-by-cnpc-researcher-amid-slowdown

[13] http://aperc.ieej.or.jp/file/2015/9/18/S3-7+Mr_+Takayuki+Sumita_METI.pdf

prevent them from selling contracted LNG elsewhere. This growing pain is likely to result in buyers fully using their DQT, putting even more volumes on the spot market unless they can organize time swaps. But should they need further reductions beyond what the contracts allow, contract sanctity could be threatened. Meanwhile, effective TPA implemented in the region (notably Japan and China) would enable players to move LNG more easily from one market to another.

Evolution of the gas price environment in 2010-14

While international gas trade has become increasingly influenced by gas-on-gas competition (GOG) pricing mechanism, LNG trade remains heavily affected by oil indexation. As of 2014, around 75 percent of LNG traded is based on oil indexation, mostly in Asia. Meanwhile, 50 percent of pricing in pipeline trade was based on GOG.[14] Oil indexation has been increasingly questioned by Asian buyers as the rationale of oil being a competing fuel against natural gas has been progressively diminishing over the past 20 years. A fundamental question is therefore whether Asia LNG contracts will undergo a similar transition from oil-linked to GOG that took place in North America and Europe.

Pressure for a move in price formation away from an oil/JCC linkage has grown substantially in the 2010s driven by the sharp increase in oil prices. This coincided with the Fukushima nuclear accident, which created significant additional demand for LNG in Japan, rising LNG consumption in other Asian markets, notably China, and the increase in North American shale gas production that drove US gas prices down. During the high oil price period (2010-14), Asian buyers were paying the so-called Asian premium with LNG imports averaging $14-18/MMBtu for Japan, Korea and Taiwan and $9-14/MMBtu for China and India. In Japan, limited ability to pass high costs to end-users resulted in Japanese utilities making multi-billion dollar annual losses.[15]

Asian buyers have considered a number of different options to cut their LNG import costs: 'cheaper' US LNG, using spot indices or creating one or several trading hubs in Asia.

- In a context of high Asian LNG prices, US LNG export projects were particularly attractive to Asian buyers, offering modified tolling contracts, LNG prices based on Henry Hub and delivered FOB. The formulae (1.15 x HH + liquefaction fee + transport costs) put US LNG at around $10/MMBtu for an HH price of $4/MMBtu. Consequently, companies in Japan, Korea, India, and Indonesia signed long-term tolling and supply contracts to import US LNG.
- As spot trade increased, a number of different Asian spot price indices started to be published. The four best known are: Platts' Japan/Korea Marker (or JKM), ICIS' East Asia Index (EAX), Argus' North East Asia (ANEA) and RIM Intelligence. These indices are already being used for some medium and short-term contracts. With greater liquidity in short-term LNG markets, the importance of these spot indices could increase.
- Unlike in North America and Europe, there is no trading hub in Asia. In 2013, the IEA identified elements that are crucial for the development of trading hubs: gas price liberalization (notably the inability to pass through gas purchase costs to customers), government's hand off attitude, and a functioning third-party access to gas infrastructure. These elements are still lacking in most Asian markets with the exception of Singapore. Also, Asian gas markets are not as mature as North America and Europe were when hubs were created. They depend significantly on LNG imports (except for China) while Europe and North America relied on domestic production and

[14] IGU, Wholesale Gas Price Survey 2015 Edition.

[15] Rogers, H.V. and Stern, J. (2014), `Challenges to JCC Pricing in Asian LNG Markets', NG81, OIES. http://www.oxfordenergy.org/2014/02/challenges-to-jcc-pricing-in-asian-lng-markets-2/

imported pipeline gas.[16] Consequently, the establishment of a trading hub was considered to be at least a decade away.

In 2015, some progress were made in Japan and China. In Japan, legislation to liberalize the wholesale gas market passed through the Diet. The retail market will be open by end-2017, while the separation of pipeline operations from supply is planned for 2022. In China, reforms were announced to unbundle the pipeline transportation and storage infrastructure (but not the LNG assets), of the three major companies. The price reform, which started at the end of 2011, introduced citygate prices based on a netback of alternative fuels rather than reflecting gas supply/demand. Nevertheless, small quantities of LNG are traded in Shanghai. Meanwhile, India and Korea are lagging behind in terms of reforms of the pricing system or liberalization of their gas markets, respectively. While Singapore can be seen as the strongest candidate for Asia's first gas hub in terms of market conditions, it is a relatively small market and will remain so despite the planned expansion of LNG import capacity. That said, it could become a pricing hub for the trade of small-scale LNG in Southeast Asia.

In the short and medium term, pricing could become hybrid, involving different elements of oil indexation, HH prices, and spot indices. But this would still not fully reflect regional gas supply/demand conditions.

A change of players

The rise of aggregators and the increase in portfolio LNG has been accompanied by new players entering the LNG sector, challenging traditional business models and norms of the business. While companies like Enron promoted different business models in the late 1990s, banks appeared in LNG trading in the 2000s. Those that survived the economic crisis contributed to developing the liquidity of the paper market, notably in Asia. Finally, traders such as Trafigura, Vitol, Gunvor, and Glencore are increasingly involved in LNG trade and supply. They supply existing and new LNG markets, with some recent major success in Mexico, Egypt, Pakistan and Argentina, and are even engaged in some term deals with established buyers.

- Trafigura '*expects the LNG markets to reach a tipping point during this decade: While in the past industry players (had) to commit to long-term contracts, as infrastructure is put in place, the spot market is becoming more active and freely traded volumes are growing*'[17]. In order to provide confidence about security of supply to customers and to gain a trading advantage over its competitors, Trafigura is using Petronet's underutilized Kochi import terminal in India for storage, taken capacity in Singapore LNG and has secured access to shipping by using cargoes without long-term commitments.
- Gunvor Group was reportedly set to expand into short-term trade of LNG in 2014; in 2015, it won a tender to supply 120 cargoes to Pakistan over 2016-20.
- Glencore plans to double its global LNG trading team and trade as many as 50 cargoes in 2016 despite difficulties in late 2015
- With 3 mtpa traded in 2013, Vitol is using its three dedicated LNG vessels on time charters to supply LNG based on spot, short-term and long-term contracts. In 2012, it signed a 10-year supply deal with Komipo and delivered spot cargoes to Egypt in 2015.

New entities with new business models are also appearing in traditional LNG markets. JERA, the joint-venture between TEPCO and Chubu (making it the largest global LNG buyer), announced in 2015 a diversification of its procurement portfolio that uses long-term, mid-term, short-term and

[16] Most Asian gas markets will remain heavily dependent on LNG imports, with the exception of China.
[17] http://www.trafigura.com/our-services/oil-petroleum-products/lng/

spot transactions.[18] In China, entrants such as JOVO and ENN Holding are trying to import spot LNG cargoes. Apart from these big corporates, new LNG importing countries have appeared. Some, like Egypt, may have import needs for a limited but uncertain duration as other domestic supply options arise. Most will have credit issues, forcing them to buy LNG by issuing tenders for a specific number of cargoes, thus relying on the spot market, which was largely done by Egypt, Pakistan and Jordan in 2015.

INCREASING VOLUMES OF SPOT AND SHORT-TERM LNG TO 2025

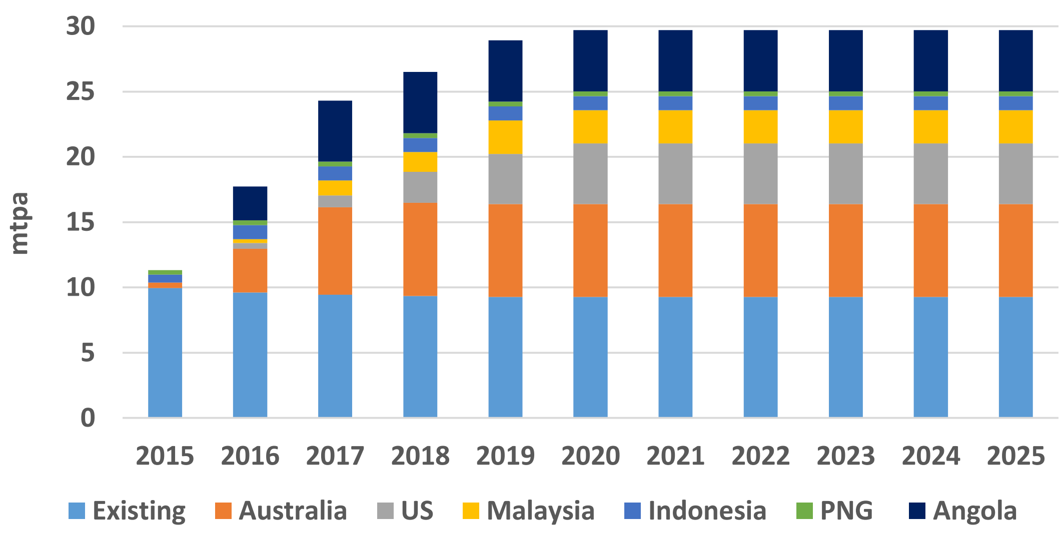
Uncommitted LNG

Some LNG export projects have taken FID without 100 percent offtake commitments by buyers. This is notably the case for Australian and US plants. Gorgon LNG and Wheatstone LNG have more uncontracted LNG than usual as two Heads of Agreement (HoA) of 1.5 mtpa each with KOGAS were cancelled in 2011. Angola also has no contracts attached to capacity that was originally earmarked for the US and is likely to play a role in spot markets when the plant comes back online in 2016.

This new uncommitted capacity builds on existing volumes, which we have earlier assessed as about 10 mtpa in 2014. This part is expected to remain relatively constant, except for Abu Dhabi, where domestic demand for natural gas is rising and development of domestic production is hampered by low local gas prices. There is also uncertainty on future Algerian and Nigerian uncommitted capacity. As a result, we estimate between 8 and 10 mtpa of existing uncommitted LNG will be available for spot trading. Meanwhile, debottlenecking of existing plants could add spare capacity that is not yet booked and has not been included in the total above. Qatar could add another 12 mtpa by debottlenecking its existing capacity, should the moratorium on additional exports be lifted.

In total, uncommitted capacity is expected to almost triple by 2020 (Figure 3). However, the scene is not set in stone. It is entirely plausible that some of this LNG will eventually be contracted; however, buyers have become extremely cautious about committing for 20-25 years and wary about sudden demand changes in their own markets.

Figure 3 Estimated uncommitted LNG supply, 2015-25



Source: author's research. Existing includes existing uncommitted volumes from Australia, Malaysia and Indonesia.

[18] http://aperc.ieej.or.jp/file/2015/9/18/S3_Mr_+Yuji+Kakimi_JERA+ver2.pdf

Less appetite for contract renegotiations?

Significant amounts of LNG contracts will expire over the next 10 years (including some starting from 2015). This provides an opportunity to buyers (particularly for key Asian players) either to achieve better deals or to not re-enter long-term contracts and instead rely on the spot market. They could also extend the contract but with reduced volumes. A total of 135 mtpa of existing contract volume will expire in 2015-25 (including 54 mtpa in 2015-20) with about 64 mtpa targeting Japan and Korea (but only 1 mtpa from China) and originate mainly from Malaysia, Australia and Qatar. Meanwhile, over 120 mtpa of new supply contracts will start from 2015, including around 35 mtpa targeting Japan, which could be replacement volumes for expiring contracts. Interestingly, one third of these expiring contracts are in the hands of aggregators on the buyers' side, including those contracts designed as portfolio.

In the past, when LNG contracts expire, sellers and buyers have agreed to extend them based on the same or lower quantities. Unlike new liquefaction plants, at the end of a 20-year contract, investments are already amortized with further operations not needing third-party financing. This may encourage suppliers to retain more output for spot market or sell LNG on more flexible terms. But as mentioned earlier, the environment today is unlike anything we have seen before. Demand uncertainty from once predictable buyers and issues regarding pricing mechanisms are combining to put pressure on suppliers. In an oversupply situation, the LNG market shifts in favour of buyers who are keen to obtain better contractual conditions, notably more flexibility and lower prices (or move away from JCC-indexed prices). In this environment, contracts may not be extended, not because suppliers want to keep some LNG for spot trading, but because buyers do not wish to extend contracts or will extend them only by taking reduced volumes.

Forthcoming changes on the supply side are another aspect of the contract renegotiations. In many instances, partners in LNG projects have marketed their LNG as a group or under a joint-venture rather than as individual companies. This characteristic has been challenged in a few projects. For example, NWS partners changed their structure in 2015 to sell LNG volumes individually. Portfolio suppliers in NWS sought this change in order to optimize their positions, such that they can sell to third parties as part of their aggregator volumes. It means that uncontracted and excess LNG would be returned to individual equity partners, who would be able to sell volumes bilaterally either through spot trades or tenders. While the change will not affect existing long-term contracts, some contracts will expire by 2017, while smaller partners in the joint venture may see their negotiating position weakened.

Looking at each long-term contract and exporting country individually, we have come up with potential ranges for the LNG supply contracts that would not be extended. In some cases, exports could stop altogether or more LNG would be diverted to the domestic market, such that countries would not have any LNG available despite contracts expiring.[19] In other cases, LNG contracts are not extended due to the buyer's decision. Based on this analysis, it is estimated that quantities potentially available to the spot market would increase regularly before reaching about 36 mtpa to as much as 45 mtpa by 2025.

The role of Qatar and US LNG

Qatar's role in short-term and spot trading has been rising to reach 25 mtpa in 2014. Quantities increased significantly over 2010-14 as Qatar optimized its portfolio, finding alternatives for the US and UK markets, where it had initially planned to send large amounts of LNG. The growth in Asian LNG demand, notably after Fukushima, enabled Qatar to find these alternatives.

[19] Portfolio LNG has been excluded to avoid double counting.

The key question in estimating Qatar's capability to contribute to the spot market going forward is: how much of Qatar's LNG can be diverted and how much it is willing to divert? The country currently has 27 mtpa contracted to Japan, Korea and Taiwan, 15 mtpa to China and India, with 30 mtpa to Europe and 5 mtpa to other destinations. Assuming all contracted LNG to Europe and other destinations as flexible and all that is bound for Asia as inflexible is too simplistic. Trade in 2014 has shown that despite the Asian premium, Qatar did not send all its LNG to Asia. We can therefore consider that the 17.6 mtpa reaching Europe in 2014 is probably the minimum volume Qatar would send. The 5 mtpa to North America or 'portfolio' supplies are considered flexible. Meanwhile, some LNG previously diverted to Asia returned to Europe in 2015 due to reduced demand in Asia and new LNG supply starting up in Australia.

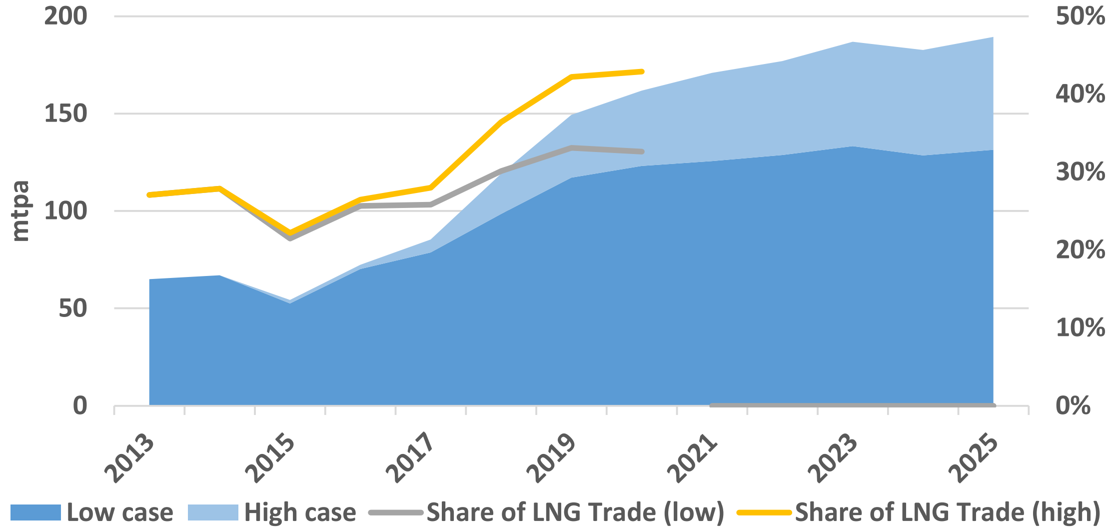
Looking forward, Qatar is likely to have to adapt, like all suppliers, to the new oversupply and pricing environment, while buyers will continue to test their flexibility options. Taking into account existing contracts as well as the appetite for flexibility from different players, we estimate that spot and short-term trading from Qatar is likely to decline or plateau over the coming years as LNG switches back to Europe under the framework of existing long-term contracts and direct supply to the UK market through South Hook, Qatar's 15.6 mtpa regasification terminal. However, expiring long-term contracts and the need for more flexibility from existing buyers means that these quantities could range between 23 and 26 mtpa by 2020 – roughly at the 2014 level – but increase to between 29 and 39 mtpa by 2025 due to a partial extension of existing long-term contracts.

The advent of North America's non destination-bound LNG supply will create a major new source of flexible LNG, challenging traditional supplies from the Middle East and Africa in Europe and Qatar and Australia in Asia. However, forthcoming US LNG sales will shift both price and volume risks onto the buyers. This contrasts with the previous position where the buyer took the volume and the supplier the price risks. Taking into account US portfolio LNG and uncommitted US LNG, there is still a large share of flexible US LNG that was contracted by players who would in principle sell it in their home markets, but could face challenges if oil prices stay low while HH prices recover. Indeed, at $40 or $50 oil, very low HH prices are required for US LNG to be competitive either in Europe or in Asia against oil-indexed LNG.

Towards an inflexion point?

Adding up all the elements previously analyzed – uncommitted LNG, portfolio LNG, Qatari and US LNG as well as the lack of appetite for contract extensions, we arrive at a range of potential evolution for spot and short-term LNG trading. In the higher case, we included fully flexible US LNG. The higher case shows a significant rise of between 120 and 160 mtpa to 2020, increasing to between 130 and 190 mtpa by 2025. There is one caveat to this analysis: the supply picture to 2020 and thus the share of spot and short-term LNG trade can be given with some confidence, but the situation post-2020 is plagued with uncertainty. While contracts supporting these LNG projects could diminish the share of spot and short-term trading in total LNG trade, these projects could also include a small share of uncommitted LNG that would feed the spot market as well as portfolio LNG not backed up by secondary sales. Besides, newly signed contracts (from existing and new capacity) could provide an additional pressure on the expiring contracts, if the pricing and flexibility conditions suit the buyers better. This would then lead to even more of the expiring contracts not being extended compared with our higher case. Finally, if buyers negotiate more flexibility in their new contracts, this feature may also feed the spot market if buyers need to use it.

Figure 4 Evolution of spot and short-term LNG trade



Source: author's research.

THE IMPACT OF LOWER OIL AND GAS PRICES

Lower oil and gas prices have changed many aspects of the LNG market. Asian spot gas prices collapsed at the beginning of 2014 – well ahead of long-term contract prices – and have been at around $7-8/MMBtu during 2015. Then, the decline in oil prices led to a drop in contract prices in early 2015. This means that as of early 2016 European and Asian have substantially converged, even though European spot prices are still much lower. Meanwhile, the upcoming LNG wave described earlier suggests that a lower LNG price environment could last for a few years.

The impact is already felt on the supply side: only Cheniere's Corpus Christi T1 and T2, Sabine Pass T5, Freeport T3 as well as Cameroon LNG took FID in 2015. Cheniere's and Freeport LNG projects had already secured most long-term capacity contracts before the oil price collapse. Lower oil prices have nevertheless considerably changed the outlook for US LNG. A crude oil price of $40/bbl requires a Henry Hub price of $1/MMBtu for US LNG to be competitive in Asia[20]. Even though US LNG contracts provide a way to diversify price risk away from JCC for Asian buyers, a sustained low oil price environment would cause problems for the offtakers of US LNG with the liquefaction fee to pay. Meanwhile, FIDs in other regions such as Canada, Russia and Eastern Africa have been postponed.

On the buyer side, the `Asian premium' has disappeared and therefore reduced the urgency to change traditional JCC pricing. Still, many utilities, notably in Japan, have faced multi-billion dollar losses since 2011, though should experience some relief in 2015 due to the lower oil and LNG prices. Similar financial distress prompted contractual changes in Europe a few years ago. Should the oil price recover, Asian buyers would again face the same issues as in 2010-14. It can be very difficult to agree to change a price in an existing contract, particularly if a price review clause is either absent or too general. It may also be difficult to change the contract terms to include a price review clause that would allow for a complete change of price formation in the event of a market hub being created in either the buyer's country or the region. However, the expiry of existing – or negotiating new – contracts mentioned earlier provides an opportunity to rethink the price formation mechanism.

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[20] Using an oil linked formulae of 0.145 * Oil Price + 0.8 and a US LNG formulae of 1.15 x HH + 3.0 + 2.5

CONCLUSIONS

Spot and short-term LNG trade are expected to continue rising, potentially reaching 45 percent of global LNG trade by 2020. Increased supply side flexibility is already embedded in higher volumes of uncommitted LNG, portfolio LNG, and US LNG that is not destination bound.

Buyers are applying pressure on all suppliers to adapt to their changing needs in terms of flexibility and prices. Rising demand uncertainties and liberalization in Asia increasingly expose gas and power companies to risks in deregulated markets such that they are more careful about committing to long-term volumes. Meanwhile, the emergence of small and less creditworthy buyers in developing markets pushes them to rely more on the spot market. Finally, trading houses are actively supporting the growth of spot LNG trade, notably by supplying the less creditworthy players. A further increase of spot trading beyond 2020 depends on how many FIDs would be taken for new liquefaction capacity over the coming years, and what would be the amount of uncommitted LNG and portfolio LNG that is not backed by secondary sales within these contracts.

The rise in spot and short-term LNG trade will increasingly allow buyers to source their LNG from the market rather than rely on long-term contracts. This is expected to create a virtuous cycle: as market players get accustomed to buy and sell spot LNG, they in turn increase spot trading and liquidity. This growth of liquidity is unlikely to be linear though. This increase could provide the physical basis for creating a hub reference price for LNG in Asia, though the location of this hub and the speed at which it could develop sufficient trading liquidity is not clear.

This increase of spot LNG trade will coincide with an anticipated oversupply over the coming few years, which could leave cargoes available at distressed prices, below long-term oil-indexed contracts. Problems could arise for long-term contracts if low demand for LNG is combined with these increasing volumes of cheaper LNG cargoes. In Asia, improved access to LNG terminals and pipelines notably in Japan and China could allow new market players to import these cheaper cargoes and therefore undercut established utilities sourcing their LNG under long-term JCC-linked contracts. In order to preserve market share, the only solution would be to undercut these new entrants by offering gas at lower prices. New financial difficulties could arise from this situation as these buyers are also tied by long-term contracts. A similar situation in Europe in 2009-10 led to a renegotiation of long-term contracts. But European contracts contained renegotiation clauses, which are often either absent or quite general in Asian LNG contracts.

Another set of players potentially at risk are those with US LNG contracts who will find out that US LNG is actually more expensive that oil-linked contracts in Asia or Europe. It is questionable whether these companies will be able to market this LNG on the basis of the variable costs (cash costs) for an extended period where the liquefaction fee and shipping costs are considered as a sunk costs that would not be fully recovered.

So far oil indexation still dominates the pricing mechanisms of LNG contracts. While some short-term contracts already include Asian spot indices as part of the price formula, the emergence of a trading hub in Asia still remains an elusive prospect for the short term, requiring at least 5-10 years.

In the current environment, it will remain difficult for new greenfield LNG projects to move ahead. Brownfield expansions stand better chances, but demand uncertainty is still a challenge. If additional LNG demand is limited, and costs cannot be significantly reduced, this will mean very few new FIDs. If a pause is taken in terms of FIDs, LNG project sponsors may find themselves in a different environment by the early to mid-2020s. While it is unlikely that project sponsors would currently trust financial derivatives to hedge project risk and move ahead without sufficient long-term contracts; a growing spot market with sufficient liquidity will force contract terms to adapt to provide the flexibility desired by buyers including the end of destination clauses and competitive LNG pricing structures.