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Assessment of Market Trends in Liquefied Natural Gas

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Introduction

Recent market developments point to a fundamental change in the role of Liquefied Natural Gas (LNG) in the global energy landscape. The share of LNG as a means of transportation for natural gas is poised to grow dramatically in the foreseeable future, but there are also significant uncertainties. LNG supply has continued to saturate the global market in 2016, and supplies will likely continue to increase. The major question analysts are asking is whether this incremental liquefaction will prove to be too much relative to short-term demand projections, and whether the industry will survive in spite of what looks to be a protracted period of low prices.

On the demand side, natural gas is a major energy source for power generation, residential heating and feedstock for industrial production. LNG offers a flexible means of transporting this energy source without the need for inter-regional pipeline infrastructure. While excess LNG import capacity and higher costs compared with pipeline transport have dampened enthusiasm for LNG in recent years, current trends point to increased reliance on LNG to supply the world's energy needs. Growing demand for gas (in some regions), diversification of suppliers, new pricing mechanisms and the development of disruptive technologies have opened the potential for regionally isolated LNG trading to grow into a robust, more transparent global market. Growing international concern over energy and environmental security has led to policies from both gas importing and exporting nations that will likely increase LNG trade in coming years. The following chapter examines the major trends currently affecting the LNG market and their implications going forward.

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First, long-term projections on global gas trade show growing supply amongst exporters as demand from importers also increases. With limited potential for development of new pipeline capacity, LNG will likely play a key role in moving the resulting growth in traded volumes. While excess LNG exporting capacity will give consumers leverage in pricing (for at least the next decade), increased trading activity will require further investment in the following decades. Investment in intra-regional infrastructure will be crucial to bring growing capacity from production plants to receiving terminals. Short term market trends will put pressure on investment needs due to increased uncertainty in overall natural gas demand as well as LNG demand.

Second, changes in pricing mechanisms will provide consumers with more flexibility as the importance of short-term trading and gas-on-gas pricing grows. In the current market of low oil prices, divergence from the historic oil-to-gas price spread threatens to hurt the economics of new projects currently under consideration. In the long-run, however, LNG capacity needs to increase to meet projected import requirements, and pricing will have to accommodate new projects. Third, the introduction of disruptive technologies to LNG markets will potentially add more flexible supply options through increased use of small scale LNG and floating terminals to extend the supply chain into underserved areas.

Finally, incentives exist for all major regions participating in the LNG market to support policies favoring LNG. This is based on concerns around environment, energy security and economic development. While the above-described trends will increase the relevance of LNG in global energy markets, decisions by policy makers will be decisive regarding the speed, availability and affordability LNG.

This report is the result of research undertaken by Columbia University's research team for the United Nations Economic Commission for Europe's Group of Experts on Gas. Under the overarching goal of exploring key trends in global LNG trade, the team is part of the Task Force on Best Practice Guidance for Liquefied Natural Gas. The primary goal of this effort is to provide a data-driven assessment of evolving trends in order to facilitate informed policy discussion at the national and international level. The team relied on data provided by leading organizations including IEA, IGU, GIIGNL, EIA, as well as interviews with experts.

I. Regional LNG Supply and Demand

A. Growing split between importers and exporters of natural gas will spur an increase in LNG trading volumes

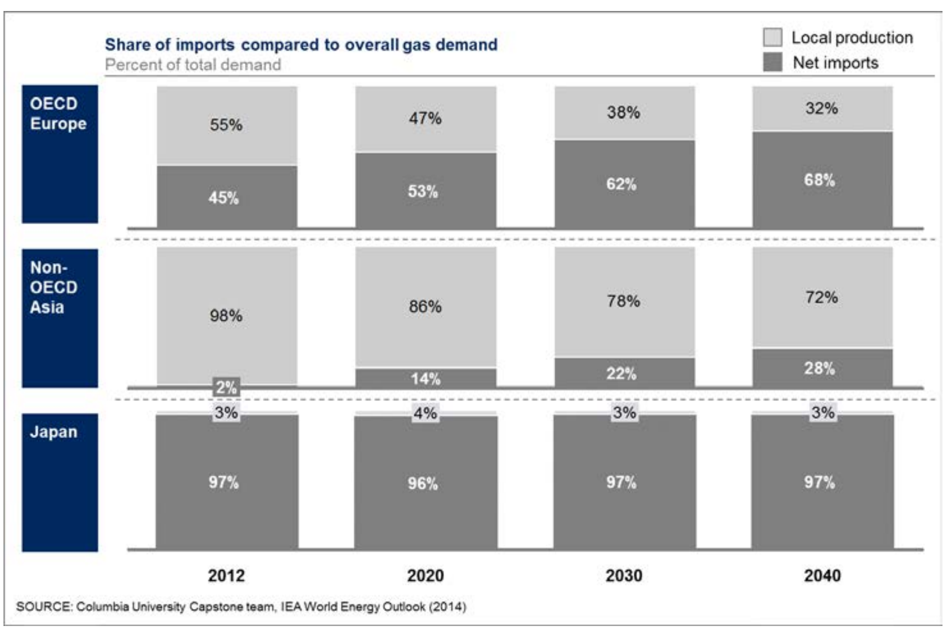
Forecasts[1] predict OECD Europe and Non-OECD Asia will rely increasingly on natural gas imports to meet natural gas demand in the coming decades. Combined with near absolute dependence on imports in Japan, this trend challenges net importing regions to ensure reliable and affordable energy supply. LNG will likely play a central role in addressing these challenges.

In the case of OECD Europe, moderate growth in natural gas demand and declines in local production will increase the share of imports from 45% to 68% of natural gas consumption (fig. 1A.1). Demand growth will be driven primarily by increased demand for power generation from natural gas. Moderate residential gas demand growth and industrial gas demand contraction will have a less significant effect on aggregate demand (table 1A.1).

In Non-OECD Asia, increased dependency on natural gas imports will be even more profound, with the import need jumping from 2% to 28% of total demand (fig. 1A.1). Growing demand will be driven by strong growth in natural gas consumption, which will far outpace slower growth in local production. In contrast to OECD European demand growth. In Non-OECD Asia demand growth will be driven primarily by industrial consumption with increases in consumption for residential use and power generation further contributing to the trend (table 1A.1).

In Japan, reliance on imports is already near absolute and will remain steady in the coming years. Stagnant import demand is projected as a result of moderate growth in industrial demand for gas, offset by a decline in demand for gas for power generation and residential use (table 1A.1).

Fig. 1A.1



[1] IEA, *World Economic Outlook 2014*

Table 1A.1

	CAGR 2012-2040		
	Europe	**Non-OECD Asia**	**Japan**
Gas demand	**1.2%**	**3.8%**	**0.0%**
Power	2.3%	3.9%	-0.8%
Industry	-0.6%	5.4%	1.7%
Buildings	0.4%	4.4%	1.0%
Gas production	**-0.8%**	**2.6%**	**0.0%**

Source: IEA, *World Economic Outlook*, Columbia University Capstone team

These projections reflect IEA's assumptions for the coming decades under the current policy environment. However, this trajectory is also subject to unforeseen market developments. Demand, for example, could increase faster if GDP grows stronger than expected. Significant increases in energy efficiency or slower growth in major regions, by contrast, could result in weaker demand growth. Additionally, supply could change due to the discovery of new reserves or significant progress in non-conventional production in importing regions. Disappointing global gas demand in the short-run could, and will likely pile-on to abundant near-term supply to pressure global gas markets. Despite expected positive longer-term gas demand growth prospects there is increasing uncertainty.

Oil is the cheapest it's been in years, and – regardless of what happens next – this bear market has already persisted too long to be considered fleeting. As a result natural gas stakeholders are forced to reconsider the implications of what had for many years been a gaping spread between the global oil price of roughly $100/bbl and North American gas price of <$5/MMBtu (the equivalent of <$30/bbl). That previously massive disparity promoted adoption of gas as a substitute for oil in key transportation and industrial sectors. Pricing no longer necessarily favors oil-gas substitution, at least for now, and at least in certain parts of the world. While demand from some of these applications may still expand in North America where gas is particularly cheap and abundant, expansion of small scale LNG for industry or transportation in Europe, for example, seems more challenging in this price environment.

BP's Energy Outlook - 2016 shows emerging markets contributing of global growth in natural gas demand between now and 2035, with China and India together accounting for around 30% of this increase. [2] And, although international gas trade as a whole will remain at 30% of global energy consumption, the LNG trade is expected to grow by 40% over the next five years, and will overtake trade by pipelines by 2035.

Although it is largely viewed that emerging market gas demand growth will lead global growth in the long-run, certain indicators give pause with respect to short-term potential. Two of the world's largest developing economies, China and India, are not increasing LNG imports at the expected rates. Chinese LNG imports actually decreased year-over-year in both 2014 and 2015 (8,6% and 5,7% respectively) and the current economic outlook does not bode well for near term growth.

And, while an August 2015 report from the Canadian Imperial Bank of Commerce predicts that China will require an impressive 13.8 bcf/day of imported gas by 2020, compared

[2] http://www.bp.com/en/global/corporate/energy-economics/energy-outlook-2035/energy-outlook-downloads.html

to 5.2 bcf/day in 2014, it also warns that Chinese LNG demand may not materialize because the “volume of gas available by pipeline from Russia, Turkmenistan, and other Eurasian countries could sate that growth, leaving little room for incremental LNG imports.”

Meanwhile, LNG imports to India may remain rare for now. According to the same report, Indian LNG demand has been very price sensitive and India has been a tough customer in gas price negotiations. Though the Indian government claims that it would like to import natural gas, it has demonstrated a preference toward coal, which is cheaper. Currently, the Indian government is drawing plans for the world’s largest renewable energy program (up to 175 GW), which will require gas-powered plants to serve as the base for renewables. India’s Minister of Power and Coal has said that India is ready to commit to long-term fixed priced contracts, but – importantly – only if the price is “affordable” to power producers. Indian coal is very cheap and India’s understanding of an “affordable price” for gas may differ significantly from rest of the world.

In the OECD, too, short-term speed bumps may limit gas demand growth. Namely, the restart of nuclear capacity in Japan will deflate what had been elevated gas demand there, and low oil prices will likely slow opportunities for oil-gas substitution. However, we also believe that the potential for expanding LNG applications in the OECD in the long-run may be underappreciated, relative to expectations for non-OECD growth. New applications for LNG as a direct substitute for oil in both transportation and industry could lead to demand that surprises to the upside.

Currently, hopes for increased demand come from Argentina. Argentina's tender to buy 32 LNG cargoes for April to August 2016 delivery brought some new activity to the market. Kuwait has also awarded a tender to buy one cargo for its new floating terminal. However, these are the only two consumers with new activity in recent months.

Policymakers at the national level have the ability to actively manage the impact of projected import dependency. Challenged with a likely scenario where current domestic supply is insufficient to meet future demand, decision makers in importing regions will have three basic options from which to choose, in order to avoid a shortfall in natural gas supply. A first option for natural gas importers is to decrease their consumption of natural gas. Improvements in energy efficiency and increased use of substitute energy sources (e.g., coal or renewables in power production) can reduce natural gas demand while fulfilling the same final energy service. Yet, this option will take time to adopt and is unlikely to cover the whole of projected demand growth. A second option is to increase import capacity and intra-regional transport infrastructure to a level commensurate with projected increases in demand. Sections B and C will describe the potential role of LNG in this approach. Finally, importing regions can diversify their supply options. Natural gas imports currently run largely through a limited number of pipelines and suppliers. Growing global LNG supply offers policy makers a path to diversify supply and increase energy security.

B: Through about 2025 excess exporting and importing capacity will give importers price leverage, afterwards LNG capacity will increase.

For years LNG producers have enjoyed a favorable position in terms of pricing and contract structure due to strong demand. However, this situation is changing. Recent and projected increases in LNG liquefaction and regasification capacity – in excess of near-term demand – imply that leverage will shift to consumers, allowing for more competitive and transparent pricing over the next decade. LNG supply has continued to saturate the global market in 2016, and will likely continue to increase. A fall in prices due to increased capacity and historic lows in oil prices, though, may pose a challenge to the economic viability of investment projects. Consequently, long-run demand growth will begin catching up with excess supply. Additional LNG infrastructure will eventually be required to meet growing trade volumes. Ultimately, the need for new investment will place upward pressure on prices and erode the near- to medium-term consumer advantage. The major question analysts are asking is whether this incremental liquefaction will prove to be too much relative to short-term demand projections, and whether the industry will survive in spite of what looks to be a protracted period of low prices.

As described in Section I Trend A, projections for regional production and consumption imply growth in the trans-border trade of natural gas. However, infrastructure capacity plays a major role in the effect that this added supply will have on the gas market.

Discoveries of new gas reserves in recent years, especially in North America and Australia, will add significantly to global supply. In February, the U.S. exported its first LNG cargo (to Brazil) from the 3 bcf capacity Sabine Pass facility. A few days later, the Australian Gorgon project launched its first production (capacity 15.6mm tonnes per annum), which will be ready for export in a couple of months. Additional LNG projects from the U.S. (99,2 bcm) Australia (60 mtp/y) and Russia (16,5 mtp/y) will follow in just a few years Other – admittedly less certain – supply prospects abound: Iran has announced its intention to launch five new LNG projects in the next three (300 bcm capacity), and Nigeria, too, intends on keeping its LNG export plan alive and will proceed with building its seventh LNG liquefaction train (8mtp/y)

With respect to global capacity for trans-border gas trade, by 2020 pipeline infrastructure will carry about one-third of net trade. However, the pipeline/LNG capacity ratio differs by region. For instance, in OECD Europe pipelines will deliver roughly half of imported gas, with the other half supplied by LNG. In Japan, on the other hand, all imports will come in the form of LNG. Export capacity in non-OECD Europe and Eurasia will be predominantly from pipeline infrastructure, while the remaining export regions will rely on LNG.

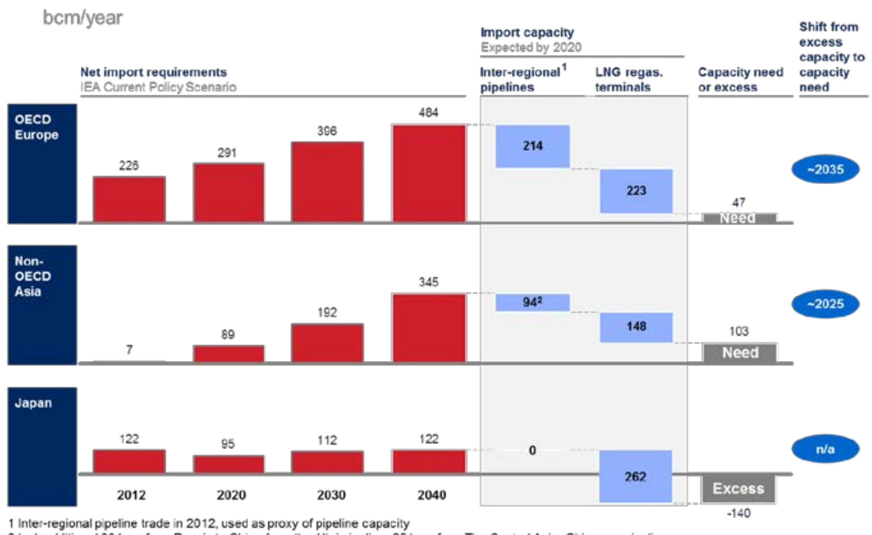
Figures 1B.1 and 1B.2 compare current and expected liquefaction/regasification capacity with projected trade requirements for both importing and exporting regions. It is important to note that this analysis assumes LNG infrastructure, rather than inter-regional pipeline capacity, will be used to meet incremental capacity needs. The current geopolitical situation and security issues in regions like the Middle East make it unlikely that additional pipeline developments will contribute more than marginal capacity increases.

Figure 1B.1 compares the projected import requirements for the years 2020, 2030 and 2040 to expected 2020 import capacity. Capacity is divided between regasification terminals and inbound inter-regional pipeline infrastructure. Both current and under-construction projects are included in regasification capacity. By comparing net imports to total capacity we can observe the shift from excess capacity to shortfall over time. Import capacity in OECD Europe is projected to meet demand until roughly 2035, while Non-OECD Asia will see a shortfall around 2025. In Japan, existing and under-construction capacity is projected to exceed import demand beyond 2040.

Supply projections for net exporting regions in the years 2020, 2030 and 2040 are shown in figure 1B.2. Projected 2020 export capacity is divided into liquefaction terminals and outbound inter-regional pipeline infrastructure. By comparing export supply to total export capacity we can identify capacity excess or shortfall by region between 2012 and 2040. For Non-OECD Europe and Eurasia, as well as the Middle East, growth in export availability is projected to exceed export capacity around 2025. In Africa and the Americas, the shift is expected to occur in 2020. Capacity in OECD Asia excluding Japan is expected to cover export supply beyond 2040.

Beyond 2025 the scenario is less clear because additional LNG trade capacity will be required to meet demand requirements. Moreover, it is not clear what price level is necessary to drive investment in new capacity. However, given current projections, additional import and export capacity will be needed, meaning prices or other market conditions will need to adjust to spur development of new projects, realigning the balance between consumers and suppliers.

Fig. 1B.1



1 Inter-regional pipeline trade in 2012, used as proxy of pipeline capacity
2 Incl. additional 30 bcm from Russia to China from the Altai pipeline, 65 bcm from The Central Asia–China gas pipeline

SOURCE: Columbia University Capstone team, IEA World Energy Outlook, BP World Energy Statistics, IGU, Bloomberg

Fig. 1B.2

1 Inter-regional pipeline trade in 2012, used as proxy of pipeline capacity
2 Incl. additional 33 bcm in OECD Americas
3 Additional 16 bcm pipeline capacity from the TANAP (Trans-Anatolian Natural Gas Pipeline) via Azerbaijan to Europe.

SOURCE: Columbia University Capstone team, IEA World Energy Outlook, BP World Energy Statistics, IGU, Bloomberg

C: Insufficient intra-regional infrastructure is becoming increasingly critical.

Effective expansion of LNG as a means of delivering gas to market requires not only regasification and liquefaction capacity for trans-regional trade, but also infrastructure to distribute and store the gas intra-regionally. At present, intra-regional infrastructure is insufficient to take full advantage of existing LNG receiving capacity in certain regions. The following paragraphs offer examples of how this constraint limits efficient distribution and solutions that have been effective for regions facing similar challenges.

OECD Europe has 223 bcm per year of regasification capacity (fig. 1C.1). However, poor connective infrastructure within OECD Europe restricts full use of this capacity for meeting broader regional demand. This limitation is particularly relevant in the Iberian Peninsula, home to more than 65 bcm/y of LNG import capacity. Spain's six LNG receiving terminals account for 40% and 32% of European storage and regasification capacity respectively.[3] However, Spanish gas infrastructure is underutilized; in 2013, Spain's LNG terminals operated at just 25% of capacity.[4]

While Spain's import capacity exceeds its demand, the infrastructure for eastward gas transmission is insufficient to provide underserved central Europe with access to LNG imports.[5] And of Spain's six coastal LNG import terminals, only three are capable of reloading LNG deliveries for re-export.[6] Five can offload LNG for transport by truck, and only one can facilitate transshipment.[7] None are capable offloading to rail transport. There are only two established cross-border pipelines cross-connecting Spanish gas imports to neighboring France.[8] Pipeline expansion between Spain and the rest of Europe could improve intra-regional distribution. However, the geographic and economic barriers to such an expansion are significant and could prove insurmountable. The United Kingdom and the Netherlands also have significant excess terminal capacity, with average utilization rates of just 20% and 5% respectively in 2013.

By contrast, Japan's use of small scale LNG offers an example of how strong intra-regional capacity can keep even geographically isolated consumers connected to the gas supply chain. Japan relies almost exclusively on LNG imports for its natural gas consumption and has very limited domestic pipeline infrastructure--only 0.01km/km2 in average, while Spain has 0.02km/km2 and Germany has 0.19km/km2. [9] However, Japan's small scale LNG capacity, totaling 10.4 bcm, [10] allows it to keep even remote areas of the country supplied with LNG. Japan's pipelines are used only to transport gas over short distances to areas of high demand. The country relies on on-shore modes of transportation, such as rail and trucks, to connect relatively low demand areas that are close to its major import terminals through a network of 91

[3] Juan De Miguel, "LNG in Spain- Key Figures and Regulatory Framework." Florence: 27 Mar. 2009, 1 May 2015. <http://www.cne.es/cgi-bin/BRSCGI.exe?CMD=VEROBJ&MLKOB=538743133939>.

[4] IGU, *World LNG Report- 2014 Edition.* IGU, Norway: 2014, <http://www.igu.org/sites/default/files/node-page-field_file/IGU%20-%20World%20LNG%20Report%20-%202014%20Edition.pdf>.

[5] ENTSOG. *Ten Year Network Development Plan*, *2011-2020.* Brussels: ENTSOG, 17 February 2011. <http://www.entsog.eu/public/uploads/files/publications/TYNDP/2012/TYNDP_Report_110217_MQ_.pdf>.

[6] The reloading is when a cargo that was previously unloaded and stored at a regasification terminal is subsequently reloaded onto another ship for sale elsewhere. See FGE.

[7] See "Transhippment," BusinessDictionary.com for definition.

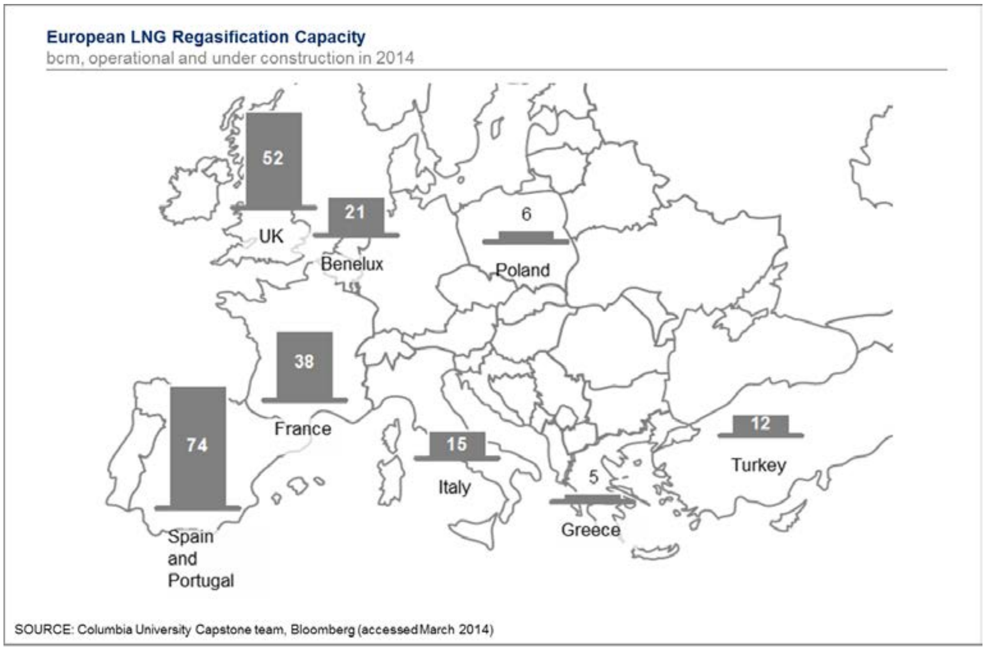
[8] Gas Infrastructure Europe (GIE), "GIE LNG Europe Map," June 2014 ed. <http://www.gie.eu/download/maps/2014/GLE_LNG_JUNE2014.pdf>.

[9] "LNG Pipeline Development in Japan, 2010," Mizuho Corporate Bank, Ltd, October 2010. <http://www.meti.go.jp/committee/kenkyukai/energy/gas_infra/001_06_00.pdf>.

[10] METI, "Presentation for the Natural Gas Systems Reform Subcommittee," July 2014, <http://www.meti.go.jp/committee/sougouenergy/kihonseisaku/gas_system/pdf/011_03_00.pdf>.

satellite terminals.[11] An additional six satellite terminals[12] via off-shore transportation ships, in order to provide energy to low demand areas over longer distances.

Fig. 1C.1



The experiences of Japan and Europe spotlight the fact that the LNG supply chain does not end at the import terminal. Consumers of LNG will benefit most from import capacity when sufficient infrastructure exists to keep import terminals connected with areas of growing demand. Growing supply flexibility and new technologies (detailed in the following sections) offer importers the opportunity to pursue creative, region-specific solutions to ensure continued intra-regional connectivity.

II. Pricing Mechanism and Drivers

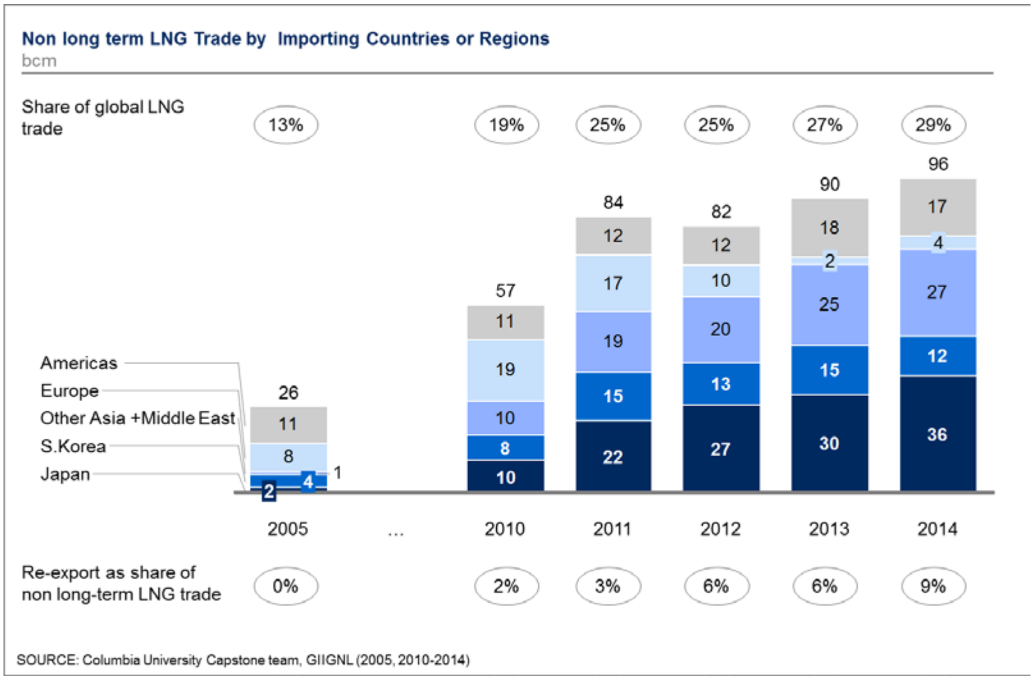
A: The share of non-long term trade including re-exports will continue to increase in the LNG market.

The last decade has seen significant growth in non-long-term contracts–including spot trades, re-exports, and contracts of less than four years, compared to long-term contracts, which have historically dominated the market. Non-long-term trade reached 96 bcm in 2014 compared with 26.34 bcm in 2005 (fig. 2A.1). This represents a jump to 29% from 13% of global trade in less than a decade. Some of this growth can be attributed to the sudden surge in Asian demand following the 2011 Fukushima Earthquake in Japan. Weak demand in Europe resulted in gas re-exports from the region beginning in 2008, accelerating this trend. The question of whether this trend will continue is one of temporal versus persistent factors. The return of nuclear power to Japan represents the major temporal downside to global LNG demand.

[11] METI, "Presentation for the Natural Gas Systems Reform Subcommittee," July 2014, <http://www.meti.go.jp/committee/sougouenergy/kihonseisaku/gas_system/pdf/011_03_00.pdf>.
[12] Ibid.

However, the emergence of the United States as a global supplier, unburdened by take-or-pay contract provisions or destination restrictions, and Asian demand for flexible LNG supply will continue to drive the trend toward increased non-long-term trading of LNG going forward. Emerging trading hubs in Singapore, Japan and China will further boost spot markets.

Fig. 2A.1



The historic prevalence of long-term contracts can be seen as a general market preference for stability over flexibility. Long-term contracts offer suppliers a predictable revenue stream and easier access to financing while ensuring supply security for consumers. Conversely, non-long-term contracts allow suppliers and consumers to choose their trading partners and volumes with more flexibility, taking advantage of changes in the market.

The recent trend toward non-long-term contracts implies an overall shift in market preference toward flexibility. Price disparities between regions due to unexpected changes in demand have been a significant driver of this shift. European demand for LNG fell significantly with the onset of the North Atlantic Credit Crisis in 2008. Asian demand, in contrast, jumped sharply after the Fukushima Earthquake in Japan in 2011. Accordingly, the market re-allocated existing supply toward a tight Asian market.

Amidst this expanding price disparity, re-exports emerged as a mechanism to level excess supply from long-term contracts to Europe with surging demand in Asia. In 2014, re-export volumes reached a high of 8.76 bcm, 9.12% of global non-long-term trade, compared to 1.36 bcm, or 2.4% of global non-long-term trade in 2010.[13] Spain, Belgium, France, the Netherlands and Portugal currently account for 95% of total re-exports.

Going forward, the return of at least some nuclear power generation operation in Japan represents the major temporal downside to global LNG demand. After the Fukushima

[13] GIIGNL, *The LNG Industry 2015*, p. 19

earthquake, Japan relied heavily on LNG as a substitute power generation fuel following the abrupt shutdown of the country's nuclear power plants. In 2011 non-long-term LNG imports spiked to 22 bcm from just 10.1 bcm in 2010.[14] Going forward, Japan's governing Liberal Democratic Party is believed to favor an energy mix with around 20% nuclear power by 2030 compared with 28.6% in 2010.[15] This partial return to nuclear power, which will take at least several years, represents an estimated downside factor of 8.3 bcm in the forecasts of non-long-term LNG trades.

Temporal upside factors, however, will offset this trend. The addition of roughly 96.6 bcm/y of new natural gas production capacity in Asia and Australia–Australia alone will bring 13.8 bcm of non-long-term contracted "wedge" volumes to market by 2017.[16] Natural gas producers tend to be conservative regarding start dates for long-term contracted LNG production. Thus, production of natural gas before the start of a long-term contract, a wedge volume, can serve as a source of non-long-term trading.

More persistent trends promise to further increase global reliance on non-long-term LNG trade. While the re-export market grew largely as a response to temporal demand shifts, it is also underpinned by persistent market changes. Destination clauses in LNG contracts are becoming more flexible, allowing diversion to alternative destination countries. Further, governments in Europe's re-exporting nations have opened up their LNG terminals to third-party accesses (TPA). In response, portfolio players including BG Group, (which recently agreed to a merger with Shell,) and GDF Suez, have entered the arbitrage market for LNG re-export. The entry of United States LNG supplies to the global market will further drive the trend toward flexibility. Five U.S. LNG plants are scheduled to begin exporting an estimated 86.87 bcm/y between 2016 and 2020.[17] If 18.9% of this new supply were to sell through non-long-term contracts or spot trading (equal to the share seen globally prior to Fukushima),[18] U.S. exports would add an estimated 16.4 bcm of non-long-term contracted LNG by 2020.[19] This represents a conservative estimate, as U.S. exports are unburdened by take-or-pay contract provisions or destination restrictions and therefore more likely to trade through non-long-term contracts. In addition, 78 bcm of new natural gas production is under construction in Australia.[20] While most of this has been traded via long-term contract, these contracts do not include destination restrictions.[21] Some new natural gas production still remains unsold. BG for example has around 4.1 bcm of unsold volumes. This will add to the pool of non-long-term LNG.[22]

On the consumer side, Asian countries have clearly shown an appetite for more flexible LNG trading. Chubu Electricity Company, the second largest electricity distributor in Japan, announced in 2014 plans to expand its use of medium-term, short-term and spot transactions to cover more than half its total LNG purchases,[23] compared with a 28.9% share of total Japanese imports.[24] This would represent a shift of 23.4 bcm out of long-term contracts. Long-term contracts between Japanese buyers and Brunei suppliers expiring in 2013 were not fully

[14] GIIGNL, *The LNG Industry 2011*, p. 19
[15] Aaron Sheldrick, "Japan's ruling party wants 20 percent nuclear power in energy mix: media," *Reuters*, 3 April 2015, 1 May 2015, <http://www.reuters.com/article/2015/04/03/us-japan-nuclear-idUSKBN0MU0AM20150403>.
[16] *LNG Business Review* July-August 2012 p. 8
[17] Jason Bordoff and Trevor Houser , "American Gas to the Rescue?" p. 28
[18] Note: 18.9% is equal to the share of non-long-term trade seen globally in 2010. This is a conservative estimation because natural gas exported by U.S. will be more flexible (without restrictions in contracts) compared to global average trading in 2010.
[19] GIIGNL, *The LNG Industry 2010* p. 3
[20] LNG Business Review July-August 2012 p. 7
[21] Ibid.
[22] Ibid.
[23] Summary Statement, LNG Producer-Consumer Conference, 6 November 2014, <http://www.lng-conference.org/pdf/summary_statement.pdf>.
[24] GIIGNL, *The LNG Industry 2015*, p. 15

extended through 2023, freeing up 4.8 bcm in residual volumes for spot trade.[25] Considering the temporal downside effect of 8.3 bcm as mentioned above, and the clear appetite by LNG buyers, which is estimated as a 23.4 bcm, the demand of non-long-term LNG in Japan will continue to increase.

New or expanding trading hubs in Japan, China, and Singapore will further drive increases in spot trading. To this end, the Ministry of Economy, Trade and Industry for the Japanese government began publishing LNG spot prices in April 2014. On September 2014, Japan OTC Exchange Inc. (JOE) in Japan launched an LNG futures market to establish price benchmarks. Shanghai also plans to offer LNG futures contracts.[26] Singapore has been developing an LNG terminal with re-export capability, in order to facilitate receipt, storage and re-export of openly traded LNG. Using generous tax incentives, Singapore's government has been working to lure LNG portfolio investors to its burgeoning market. Continued development of these markets will further boost spot and short-term trading volumes.

In summary, consumers in Asian countries show clear appetite for more flexibility and transparency in LNG trading, and new suppliers from U.S. and Australia, and re-exporters in Europe will contribute to accelerate this trend.

B: The share of Gas-on-Gas pricing will continue to grow relative to oil-indexed pricing globally, but regions will follow different paths.

In both pipeline and LNG trade gas-on-gas (GOG) pricing will continue to gain ground over oil-indexed pricing both. Overall 2013 saw 39% of gas imports priced GOG, with 44% of global pipeline trade indexed to hub or market pricing (fig. 2B.2). This comes following nine consecutive years in which GOG pricing grew as a share of total pipeline trade. Currently 29% of LNG trade is priced GOG. However, there is an uneven upward trajectory driven by volatility in marginal import volumes. Typically when countries require imports beyond their planned purchases, additional volumes are priced on a GOG basis. Regionally the trend varies, while pricing in the two main importing regions (Europe and Asia) will continue to show increased reliance on GOG as a pricing mechanism, the change will happen more slowly in Asia.

Fig. 2B.1

Three existing pricing mechanisms for gas imports

Gas-on-Gas (GOG): Prices are determined by gas supply and demand dynamics, either by trading directly at a hub or by indexing the contract price to the market price.

Oil Price Escalation (OPE): Price is set by a base price and an escalation clause linked to crude oil prices or other petroleum products.[1]

Bilateral Monopoly (BIM): Bilateral negotiations of a fixed price for a period of time, where there is one dominant buyer or seller, generally a nationally owned company.

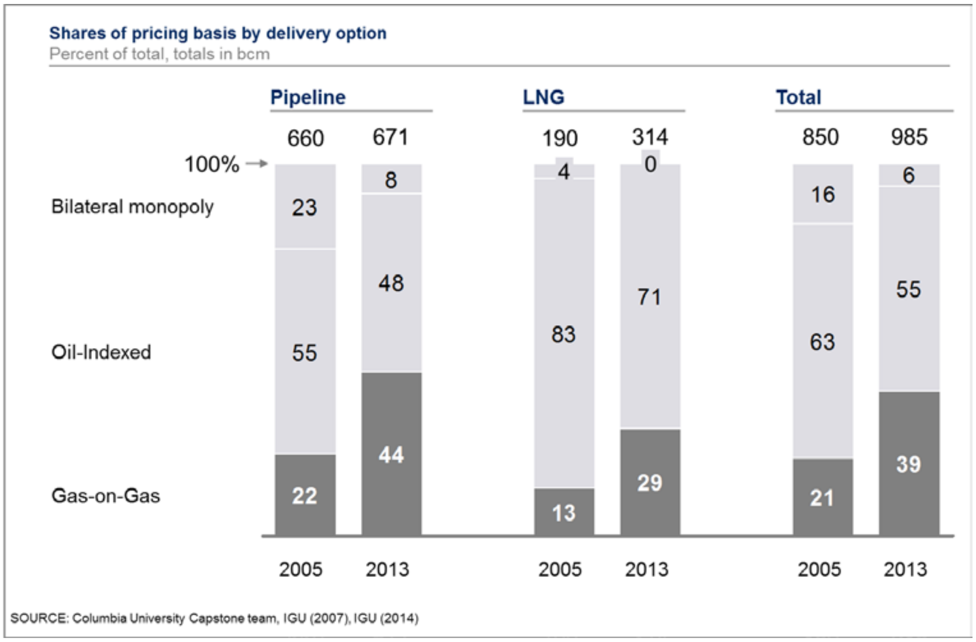
In Europe, more than 50% of trade is already conducted on a GOG basis, which until the 2014-2015 fall in oil prices put strong pressure on traditionally oil-indexed transactions to make the transition, particularly Russian pipeline imports. This trend will continue into the future for three key reasons. 1) The increased volume of spot market trading (mainly in the Netherlands and the U.K.). 2) Decreasing oil indexation in domestic production. 3) Growing supply, pushing market prices down. The speed of this change, however, is sensitive to oil prices. A

[25] IGU *World LNG Report- 2014 Edition*, p. 51
[26] "Falling Oil May Frustrate Push for Asia LNG Spot Market," *Reuters*, 28 Nov. 2014,
1 May 2015, <http://www.reuters.com/article/2014/11/28/asia-lng-pricing-idUSL3N0T92BD20141128>.

sustained period of low oil prices will slow the transition.

The share of GOG compared with oil-indexed pricing in Asia remains small in China and India where demand has been less volatile. In these countries, GOG makes up less than 10% of all transactions. Elsewhere in the region, the trend has been stronger, with almost a quarter of transactions based on market prices. Here, the trend has been driven by the strong increase in spot transactions since the 2011 Fukushima disaster.

Fig. 2B.2



In the near to medium-term, three major factors will strengthen GOG as a pricing mechanism in Asia. First, the development of trading hubs in Shanghai and Singapore, and an LNG futures market centered in Tokyo will favor gas indexing by driving price discovery, transparency and flexibility in the market (see Section II Trend A). Second, the increase in trade volume between Russia and China through the newly commissioned Power of Siberia (eastern route) pipeline is likely to be gas-indexed. Third, the entry of North America, particularly the United States, into the LNG export arena will have global effects on pricing dynamics. An additional 162 bcm/y of additional competitive capacity priced entirely by GOG could enter the market by 2040. Much of this gas is likely to end up in Asia, increasing the pressure to take up GOG as a central pricing mechanism. North American exports would represent a substantial addition to global LNG trade, which in 2013 totaled 314 bcm, (32.1% of natural gas trade) and is expected to reach 721 bcm/y in 2040.

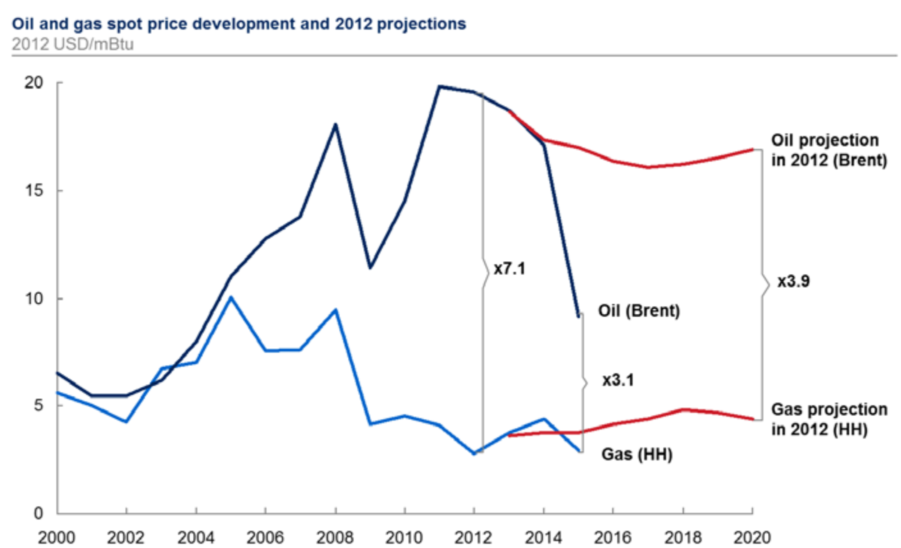
Beyond slowing down growth of GOG, the current drop in oil prices will have an uncertain effect on the long-term development of the price formation trend. While it lowers consumer pressure for GOG pricing in the market due to the reduced price of oil-indexed gas, it may also help smooth the transition to GOG pricing on the production side. Producers will see oil-indexed gas prices fall as a carry-over effect from the oil market. Because most contracts take several years to determine price, the shock of recently plummeting oil prices will have a protracted effect on the gas market.

C: A persistent low oil price could threaten some large-scale LNG projects as well as small scale LNG applications designed to replace oil demand.

Historically, oil and gas have traded in a very similar energy-equivalent price range. However, oil began trading at an increasing premium relative to natural gas around 2008. Until recently, prevailing wisdom held that this sizable premium would persist indefinitely. However, the recent collapse in oil prices has presented a strong challenge to this view.

Because the majority of LNG pricing is still indexed to oil (see Section II Trend B) low crude prices threaten the profitability of some LNG projects that were planned with the expectation of higher gas prices. In December of 2014, Asian LNG prices fell to four-year lows, trading below $10/mmbtu, compared with more than $15/mmbtu just six months earlier. Prices crept upward in the first quarter of 2015 but remained low compared with recent years (fig. 2C.1). The drop in prices threatens to erode the competitive edge driving U.S. LNG export projects. Adding feed U.S. gas price, liquefaction cost, shipping cost and regasification cost together, U.S. LNG offered a competitive export option to Asian consumers and a viable partner to Europe during peak demand seasons underpricing expectations prior to the collapse in oil prices. The recent drop in oil prices has challenged the economics of plans to export U.S. LNG to markets where demand is strongest. The current situation may constrain U.S. LNG export to the western hemisphere, if prices do not strongly rebound. It is possible that a niche export market between current and developing U.S. capacity and Mexico and the Caribbean could develop. This, however, would not represent the robust market U.S. developers hoped to reach with current export projects.

Fig. 2C.1



SOURCE: Columbia University Capstone team , Comparison of spot prices for Brent crude oil and Henry Hub natural gas, 1990-2040: History: U.S. Energy Information Administration, Monthly Energy Review September 2013, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A

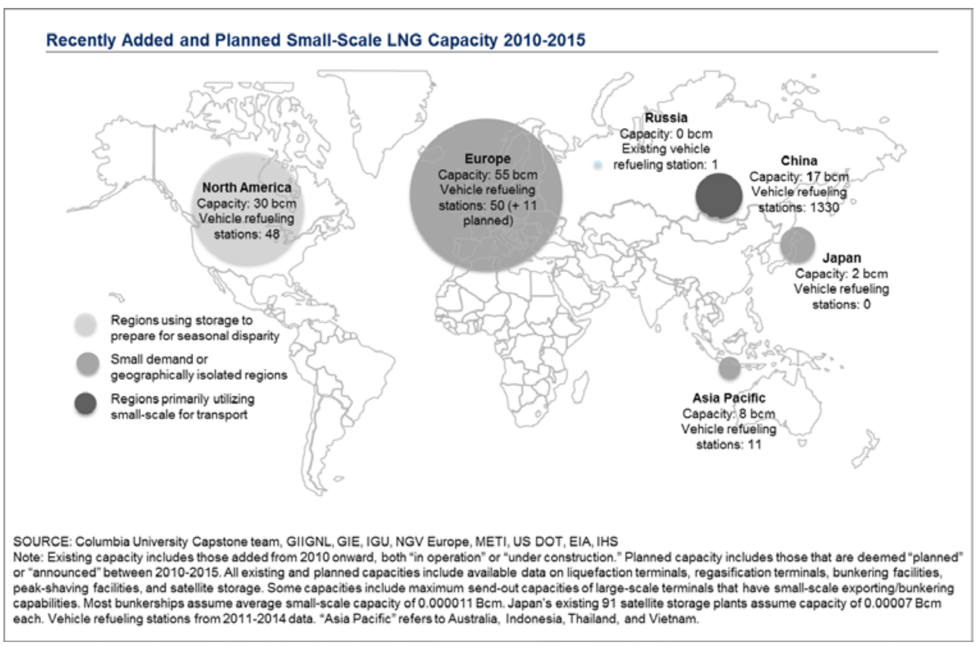
The drop in oil prices has also eliminated a major incentive for consumers to turn to LNG as a substitute for petroleum fuels. Prior to the sharp drop of oil prices, several European factories were considering adopting natural gas provided by on-site small scale LNG facilities as a fuel-source instead of diesel. However, such a transition would only be feasible given a wide spread between oil and gas prices. In an environment of low oil prices, the long-term benefits of such a conversion will be slower to catch up with initial investment costs. A similar challenge arises for consumers who might have switched to LNG for energy production or transportation under previous price structures. In short, energy consumers in all sectors will be slower to increase LNG consumption until oil prices rebound significantly.

III. Disruptive Technologies for LNG Markets

A: SSLNG will allow gas to reach currently isolated markets.

Small scale LNG (defined by the International Gas Union as liquefaction or regasification facilities with capacities below 1.38 bcm or vessel capacities below 18,000 cubic meters)[27] stands to play a meaningful role in bringing natural gas to areas that are geographically isolated, infrastructure-poor, or have seasonally inconsistent demand. Transported through bunker ships, ocean vessels, trucks and storage units, SSLNG can be used to create "virtual pipelines" in areas where construction of more costly infrastructure would be inefficient. Small scale transport of LNG can also be used to supply end-user specific sectors, particularly transportation fuel. Over the past five years, global small scale capacity has grown by 111 bcm (fig. 3A.1). Depending on region-specific circumstances, small scale LNG will not always offer advantages over large scale development. However, it holds great potential for connecting currently underserved areas with the global supply chain.

Fig. 3A.1



Recent advances in liquefaction equipment technology will contribute to making SSLNG safer and more cost effective. The transition from commonly used single mixed refrigerant (SMR) liquefaction technology to Nitrogen (N_2) expansion cycles, for example, is a potential game changer in the development of SSLNG. While SMR cycle plants require flammable

[27] IGU *World LNG Report- 2014 Edition*, p. 41

hydrocarbon refrigerants such as methane, ethane, or propane, the N_2 cycle uses noncombustible and abundant Nitrogen making the process highly favorable in small scale plants, particularly floating units.[28] The use of all-electric motor drives instead of gas turbine drives in the compression process of smaller plants represents another cost-saving innovation. Studies show that electric motor drives increase plant availability by 3-4%[29] and can cut capital expenditure costs by 36% compared to gas turbine plants of the same capacity.[30]

Applications of the above technologies to small scale liquefaction could spur further utilization among geographically isolated and infrastructure-poor regions where pipeline construction is not a viable investment. For example, two new small scale liquefaction plants have been built in Norway and Sweden in the past five years. In the same time-span, two import terminals, two bunkering facilities (plants that add fuel to vessels operating on LNG) and two bunker ships (ships that provide LNG to LNG-fueled ships or bunkering facilities) began operation, all of these represent alternative distribution services that stem from liquefaction plants. The region has plans in place for seven new small scale units. The significantly shorter build times compared to traditional LNG infrastructure has contributed to the expansion of the Scandinavian small scale network. Completion time for the Norwegian Skangass liquefaction facility was just over three years compared to average development times of four to five years for large-scale facilities. Operating at a capacity of just 0.3 bcm, Skangass demonstrates how small scale technology can quickly bring limited reserves to isolated markets where demand is strong.

In Southeast Asia, small scale liquefaction has been either been built or proposed in Indonesia, Thailand, and Vietnam. The Asia Pacific region recently added 8 bcm of new small scale capacity (fig 3A.1). South American countries including Chile, the Dominican Republic, Argentina, Peru, Brazil and Ecuador have been actively conducting studies to implement "virtual pipelines" by expanding use of conventional import terminals and construction of small scale liquefaction plants. [31]

Small scale storage has also added flexibility in regions where seasonal demand peaks are not met by pipeline gas access. Facilities store LNG in small quantities and distribute it by truck to small scale plants are referred to as satellite storage facilities. The U.S. has a total of 41 satellite storage units, predominantly comprised of storage and regasification capabilities. The U.S. also has 59 units with peak-shaving capability, where natural gas is stored in anticipation of demand spikes during the summer and winter.[32] In the past five years, Norway has built seven new units of satellite storage, while Turkey added two peak-shaving facilities. The U.K. and the Netherlands have each added one unit. For regions that are highly sensitive to natural gas prices, use of small scale LNG storage is a potential buffer against fluctuating demand.

In addition to ease of transport and accommodation of demand flexibility, small scale LNG offers benefits for new types of end-user consumption of LNG. Lower emissions and cost

[28] Joseph Pak, "Nitrogen expansion cycle enhances flexibility of small-scale LNG," Gas Processing News, 2013. <http://www.gasprocessingnews.com/features/201307/nitrogen-expansion-cycle-enhances-flexibility-of-small-scale-lng.aspx>.
[29] Charles Durr et al, "LNG Technology for the Commercially Minded," *Gastech*, 2005, <http://www.kbr.com/Newsroom/Publications/Technical-Papers/LNG-Technology-for-the-Commercially-Minded.pdf>.
[30] ABB Process Automation Oil and Gas, "All electric LNG plants: Better, safer, more reliable—and Profitable," ABB, 2006, <http://www09.abb.com/global/scot/scot216.nsf/veritydisplay/9e770a172afc8d7ec125779e004b9974/$file/Paper%20LNG_Rev%20A_lowres.pdf>.
[31] IGU *World LNG Report-2014 Edition,* p. 44
[32] EIA, "U.S. LNG Peaking Shaving and Import Facilities, 2008," <http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/lngpeakshaving_map.html>.

efficiency have contributed to growth in the use of LNG as a transportation and industrial fuel. Global use of LNG as a transportation fuel has grown significantly in recent years and will likely continue to grow in the U.S. if use of LNG as a fuel incurs one-dollar in savings compared to its per diesel-gallon equivalent.[33] Both China and the U.S. have built significant capacity for use of LNG as a road transport fuel. China currently boasts 1330 LNG refueling stations compared with 48 in the U.S. (fig. 3A.1). A global trend toward more stringent laws on carbon emissions will likely drive continued growth in the use of LNG as a transport fuel. The EU is promoting higher use of LNG as a marine fuel. Meanwhile, the mining and oil and gas industry remain actively engaged in the use of LNG in their day-to-day operations.

Use of small scale LNG is likely to develop unevenly across different regions. There is great potential for SSLNG to bring natural gas to underserved regions. However, small scale plants cannot capitalize on economies of scale that reduce per-unit costs at larger plants. Consequently, while capital expenditures for small scale development are lower, operating costs may not be. Proliferation of small scale terminals will be market-driven in regions with strong need while growing more slowly in regions where return on investment is uncertain. SSLNG has increased rapidly in Scandinavia as a method of alleviating a lack of pipeline infrastructure and will likely grow with new attempts to connect reserves to consumers. Meanwhile, China has become the world's largest consumer of LNG as a transportation fuel. China's rapid economic development has led to a large population of first time vehicle buyers and a growing fleet of cargo trucks, making conversion to LNG vehicles more practical compared to regions where diesel trucks already dominate the market. Going forward, construction of new small scale terminals is likely in the economically active regions of Vietnam, Malaysia, and Indonesia where gas demand is surging in a sparsely populated and isolated coastal region that is currently dependent on expensive diesel to fuel its industrial and power sectors.

B: Floating LNG capacity will continue to grow, particularly in regasification.

Similar to small scale technologies, developments in floating liquefaction and regasification promise to expand the global LNG market by cutting down on production costs at lower levels of production and increasing the flexibility of gas export and delivery. By moving the point of exchange offshore, floating technology offers an attractive alternative for regions where geographic or political barriers make onshore development problematic. Additionally, cost and time efficiencies in construction of floating terminals create the opportunity to bring consumer bases of limited demand and gas fields with limited reserves into the global market. The rapidly growing number of floating storage and regasification units (FSRUs) is a testament to the versatility and efficiency provided by floating technology. In contrast, the first floating *liquefaction* plants remain in the development stage. Whether floating liquefaction will have a significant impact on global capacity will remain an open question until the first floating plants come online between 2015 and 2018.

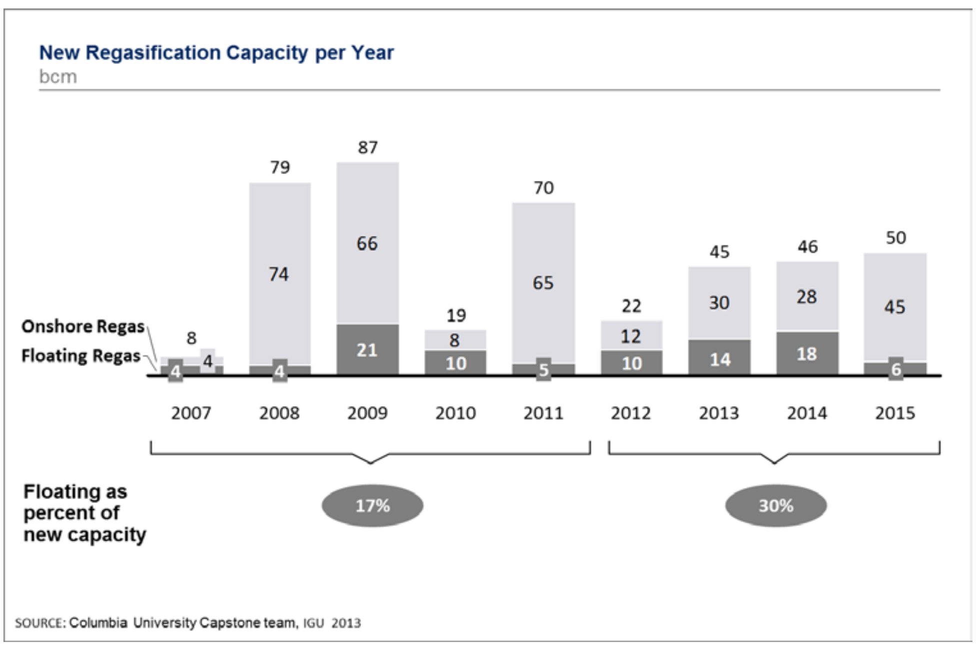
Since first entering the market in 2007, three-year moving averages for floating regasification costs have fallen consistently below those of on-shore plants, with estimates for 2016 at just over $200 per ton, compared to an average of $275 dollars per ton for on-shore gasification. Additionally, construction times for floating terminals can be as little as half those

[33] Eduard Gismatullin and Jeremy Van Loon, "Shale Glut Means $1-a-Gallon Savings at the Pump," *Bloomberg News.* May 22, 2012, 1 May 2015, <http://www.bloomberg.com/news/articles/2012-05-21/shale-glut-means-1-a-gallon-savings-at-the-pump>.

for their on-shore counterparts. Operating offshore, floating regasification terminals are not restricted to operating in deep water ports and are not subject to the same challenges regarding regulation and competition over land-use that can drive up onshore construction times and costs. In other words, regasification can take place closer to consumers regardless of whether existing shoreline development or geographic challenges preclude the development of onshore terminals.

Operation on floating vessels, however, imposes certain logistical and capacity constraints on FSRUs. As of 2014, Italy's Rovigo and Kuwait's Mina Ahmadi plant were the only operational FSRUs with nominal capacities greater than 5.2 bcm/y, with 8.0 and 7.9 bcm/y respectively.[34] By comparison, regasification capacities at onshore facilities reach as high as 41.4 bcm/y at Cheniere's forthcoming Sabine Pass facility on the Gulf Coast.[35] Operating on floating vessels, rather than onshore, also leaves FSRUs more vulnerable to adverse weather than their onshore counterparts, confining development of such projects to relatively benign waters. Despite these limitations, global floating annual regasification capacity has grown significantly since the 2007 launch of Excelerate Energy's Teesside GasPort, the world's first floating regasification vessel. Global floating regasification capacity increased from Teeside's annual 4.2 bcm to an industry-wide 1,011 bcm in 2013. Total capacity for global floating LNG terminals is expected to continue to grow. The 38.21 bcm/y of in-development floating regasification capacity expected to come online between 2012 and 2015 represents 30% of anticipated new global regasification capacity during that time (fig. 3B.1).

Fig. 3B.1



Nascent projects for floating liquefaction of onshore gas reserves offer similar potential for cost-effective capacity growth. However, until operational floating liquefaction capacity comes online, questions will remain regarding unforeseen challenges and the overall profitability of such projects. In particular, projects to add floating liquefaction capacity at the extraction site of underwater gas fields located in deep waters or far offshore offer the most extreme

[34] The Northeast Gateway facility in Massachusetts Bay has a capacity of 11.8 bcm,/y, but has not received cargos since 2010
[35] GIIGNL, *The LNG Industry 2015*, p. 19.

risk/reward trade-off. These projects, if successful, would eliminate the need for costly underwater dredging and pipeline construction in order to bring gas to onshore liquefaction facilities, scaling back the prohibitive cost of tapping remote underwater gas fields. Further, liquefaction capacity located at the site of offshore gas fields will allow for storage and export of LNG directly from the point of extraction.

The logistical challenges to development of these projects go far beyond those faced by FSRUs and floating liquefaction barges (described below). Unlike near-shore facilities FLNG liquefaction plants operating above deep water gas fields, by definition, cannot be confined to benign waters. Storage tanks like those on Royal Dutch Shell's Prelude Floating LNG facility must be designed to withstand heavy sloshing that accompanies rough seas and storm conditions.[36] Prelude, slated to go online in 2017, is planned to be the largest ocean vessel ever built and will add 4.96 bcm/y of liquefaction capacity at the Prelude gas field 200 kilometers off the Australian coast. While labor costs in Western Australia are amongst the world's highest, Prelude is being constructed in Geoje, South Korea, and will be transported over sea to the Indian Ocean upon its completion. Construction of a similar project for PETRONAS is underway at the Daewoo Shipbuilding and Marine Engineering Shipyard in Okpo, South Korea. With a second project currently under development, PETRONAS plans to bring 3.72 bcm/y of liquefaction capacity to Malaysian gas fields as soon as 2018.

The capital cost and construction time savings offered by floating liquefaction technology also offer potential to bring stranded onshore reserves to market. The Pacific Rubiales offshore liquefaction barge destined for the Colombian coast aims to bring LNG from La Creciente gas field to the global market. At a capacity of just .69 bcm/y and capital cost of roughly $300 million, the project could prove a low cost model for bringing other isolated gas reserves to market. In the long-term, time and cost efficiencies of bringing floating liquefaction barges online will likely add flexibility to the LNG supply chain. However, in the short-term, changing market conditions driven by falling oil prices have caused energy companies to postpone projects. In January 2015, Pacific Rubiales announced that plans to begin liquefaction of La Creciente gas in late 2015 would be deferred.[37]

The success or failure of these pilot projects in overcoming unforeseen challenges and remaining economically viable in the face of volatile oil prices will serve as a bellwether for the role similar projects will play in the LNG supply chain in coming years. The consulting firm KPMG estimates that Floating LNG will contribute as much as 548 bcm of liquefaction capacity to the global market by 2019, with as many as 22 vessels in operation by 2022. Such an output would represent as much as 7.5% of global capacity.[38]

[36] Offshore Engineer. "FLNG Sloshing Analysis: A Fresh Approach," 31 March 2011, 1 May 2015, <http://www.oedigital.com/pipelines/flow-assurance/item/303-flng-sloshing-analysis-a-fresh-approach>.
[37] Platts, "Pacific Rubiales' LNG Project in Colombia Delayed: Partner," 30 January 2015, 1 May 2015, <http://www.platts.com/latest-news/shipping/bogota/pacific-rubiales-lng-project-in-colombia-delayed-21927015>.
[38] KPMG Global Energy Institute, *Floating LNG: Revolution and evolution for the global industry?* KPMG International, November 2014, <http://www.kpmg.com/Global/en/IssuesAndInsights/ArticlesPublications/floating-lng/Documents/floating-LNG-evolution-and-revolution-for-the-global-industry.pdf>.

IV: Policies for LNG markets

A. Environmental, security and economic concerns will incentivize policies that support LNG supply and demand.

Our assessment is that policy makers for both importing and exporting regions have incentives to support policies with a positive impact on LNG trade. Environmental concerns, energy security and economic development will drive policies with the greatest potential to impact LNG markets. While LNG will play a growing role in global energy markets, specific decisions about the adoption of policies, their design and implementation will significantly impact trading volumes and balances. Consequently, policy makers will have the power to either accelerate or impede the current positive trend in LNG trade. When crafting policy, leaders should take into account potential effects on the LNG market.

Environmental policies relevant to LNG address three areas of regulation: limitation of carbon emissions, reduction of local impacts from production (e.g., earthquakes) and reduction of local impact from LNG transportation (e.g., spills). Specific examples of current discussions related to environmental regulation include the UN Climate Negotiations (UNFCCC), the International Convention for the Prevention of Pollution from Ships (MARPOL) and limits on natural gas production in the Netherlands due to increased earthquake risks caused by drilling activities. Overall, these environmental policies will tend to favor LNG. However, there are some initiatives that might tend to work against this trend. For example, regulation on fugitive methane emissions or on LNG carrier safety.

Fig. 4A.1

Motivation	Areas of regulation	Selected current examples	Impact on LNG	Primarily relevant in...
Environmental	Limitation of carbon emissions	UNFCCC emission commitments	+/-	All regions
	Reduction of local impact of production	Limited production in Netherlands due to earthquakes	+/-	
	Reduction of local impact of LNG transportation	MARIPOL treaty that issues stricter sulfur specifications for bunker fuels	-	
Energy security	Diversification of natural gas suppliers	European Energy Union	++	Net importing regions[1]
	Reduction of dependency on natural gas imports	Japan intention of restarting nuclear fleet	--	
	Establishment of strategic reserves	Chinese Strategic Natural Gas reserves	+	
Economic development	Support for production and exports	Facilitation of exports for US gas	++	Net exporting regions[2]
	Development of commercial hubs	Singapore hub development	+	
	Support of energy affordability	Chinese support for NG as transportation fuel	+/-	

1 OECD Europe, Non-OECD Asia, Japan
2 Non-OECD Europe and Eurasia, Africa, Middle East, Americas, OECD Asia, excl. Japan
SOURCE: Columbia University Capstone team

Energy security policies relevant to LNG markets focus on specific regulatory concerns: diversification of natural gas suppliers, reduction of dependency on natural gas imports and the establishment of strategic gas reserves. The net impact of these policies on LNG is mixed. Efforts to access a broader supplier base as well as to establish strategic reserve storage will favor LNG. However, initiatives to reduce natural gas demand through substitution or increased energy efficiency would be unfavorable for LNG imports. The establishment of the European Energy Union and development of Chinese Strategic Natural Gas reserves represent market developments that are likely to favor LNG expansion. Meanwhile, Japan's intention of resuming nuclear power production will have a negative effect.

Economic development policies relevant to the LNG market include the following concerns: support for production and exports, development of commercial hubs and support of energy affordability. Current examples of economic policy efforts impacting the LNG market include the facilitation of U.S. natural gas exports, Chinese development and expansion of an LNG-fueled heavy truck fleet and efforts by Singapore to develop an international gas hub. The overall impact of policies related to economic development is favorable for LNG as they either increase supply, support trade or can increase demand. One negative impact could result from efforts towards energy affordability or electrification efforts that may favor other energy sources such as coal.

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