International Gas Union

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World LNG Report - 2013 Edition

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1. Message from Chairman of the International Gas Union

Dear colleagues,

It is a genuine pleasure for me to present you with this first LNG Report of the IGU French Triennium. This report will be followed by other editions in 2014 and 2015, where you will find comprehensive overviews of LNG market developments for each of these years.

The current report reviews the situation of the global LNG market throughout 2012, up to the first quarter of 2013.

Two special reports have been included into this edition: “North American LNG Prospects and Challenges” and “LNG as Fuel for Transportation”.

The LNG market is a major subject of discussion for IGU experts. In the framework of its unique working structure - featuring 14 Programme Committees, Study Groups and Task Forces -, the IGU Programme Committee D develops LNG expertise by bringing together around a hundred international experts. The World LNG Report - 2013 Edition presents the first results of their common work and expertise.

The 2012-2015 Triennium is focusing on small-scale LNG, LNG as fuel, remote LNG, and LNG life cycle analysis.

The role and place of gas on the global energy arena has been strengthened in past decades. Gas, the cleanest fossil fuel and the only one expected to grow, is being recognized as the key fuel for meeting the challenge of rising energy demands.

The LNG sector follows this upwards trend as the main driver of globalization of the gas industry. In 20 years, the LNG trade has evolved from an intra-regional status to achieve worldwide growth at a 10% rate a year. It is expected to continue to grow, albeit at a slower pace, driven by new technology developments and an extreme elasticity of the market.

While reaching its 50th anniversary (2014), the LNG business will remain the most dynamic player on the global gas scene. In 2012, LNG trade slightly decreased following a downturn trend in European gas consumption. The shale gas revolution reduced the need for LNG imports in North America, while Asian market remained tight with LNG playing a key role as a substitute for nuclear power.

Thanks to advances in technology, more LNG is becoming available all the time. An impressive 26 new projects were on their way at the end of 2012. New sources are expected to come on-stream in the medium term with the US Gulf Coast, the Canadian West Coast and East Africa expanding markets and diversification.

Global LNG demand should continue to grow in the short term and the market will continue to be supply constrained at least until 2015. Traditional consumers will keep their place on the market and a large number of new players are expected to emerge. Such dynamics will accentuate the globalization of the LNG market and probably change the price environment for the benefit of a larger use of non-oil-linked pricing. It is certain that LNG prices will remain firm, but their regional dichotomy will continue to provide opportunities for arbitrage trading.

Asia will attract more and more diversified suppliers and will be the area of the largest supply growth. Strong demand from China and India, in addition to traditional importers such as Japan and Korea, will ensure that Asia Pacific market remains profitable for LNG suppliers. The US will, as it looks now, become a moderate-size exporter.

LNG is a global market with regional pricing: three distinctive regional markets with their own pricing and supply options subsist.

What will be future of LNG supply contracts? Will spot-priced short term contracts prevail over oil-linked ones? How much pressure will the LNG trade put on oil indexation in Asia? The answers will depend on the future of the nuclear generation in Asia and on the status of the new LNG projects in different parts of the world.

Wishing you a good reading and looking forward to seeing you at our next events, I remain

Yours sincerely,

Jérôme Ferrier
President of IGU

2. State of the LNG Industry

Global Trade: **LNG trade fell in 2012** after 30 years of consecutive growth. Global flows fell by 1.6% from 241.5 MT in 2011 to **237.7 MT in 2012**. The contraction was largely driven by supply-side issues in Southeast Asia and domestic and political challenges in the Middle East and North Africa (MENA) region. Japan and Korea are the world's dominant LNG importers and accounted for 52% of the market, up 4% from 2011.

Spot and Short-Term LNG Market: The spot and short-term LNG market reached **73.5 MT in 2012**, or 31% of total volumes. This is up from 65.1 MT in 2011. Qatar and Nigeria accounted for almost half of the spot exports. As a whole, **Asian buyers made up 72% of spot LNG in 2012**, but Japan, Korea, and India alone accounted for 61%. The major driver in spot and short-term trade growth has been the increased use of divertible options in flexible contracts that allows companies to arbitrage.

Global Prices: Except for the UK, major regional price points did not experience the same volatility in 2012 they saw in 2011. Henry Hub spot prices remained depressed due to strong unconventional gas production, averaging $2.75/mmBtu in 2012. The European oil-linked price (an estimate of the German Contract) remained essentially flat over the year at with an average of ~$11.65/mmBtu. Despite volatility in the second half of 2012 which saw a low of ~$14.5/mmBtu and high of ~$17.5/mmBtu, Japan's average import price maintained a ~$16/mmBtu level in 2012.

Liquefaction Plants: Only one new liquefaction project came online in 2012 (Pluto LNG in Australia), taking **global capacity to 281 MTPA**. Several projects, especially in Southeast Asia, saw less output than 2011 due to the lower feedstock availability (i.e lower than expected output at the Mahakam Block in Indonesia and a fire at the Malaysia LNG plant). Angola LNG is the next major addition for the market, and had earlier been anticipated for 2012. As of mid-2013, there were **30 trains under construction with a total capacity of 110.1 MTPA**. Many of these projects have experienced significant cost overruns in the past two years – a concerning sign for project development in new LNG plays.

New Liquefaction Tranches: The industry is now trying to gauge how emerging LNG plays will develop and whether new pricing structures will prevail rather than the traditional oil-indexed contracts. Specifically there are new supply regions that could impact the LNG market in a material way: **US Gulf Coast** and **Western Canada** due to the emergence of shale gas, **East Africa** due to prolific new deepwater basins, **floating LNG globally** because of stranded gas, and **Asia Pacific brownfield** projects.

Regasification Terminals: Global regasification capacity continued to grow in 2012 – to 642 MTPA – despite the slight drop in global LNG trade, reflecting the increased demand for gas (and LNG) in a shifting and ever-larger number of markets. **Regasification utilization fell** from 40% in 2011 to **37% in 2012**. Since mid-2012, two new countries have brought online regasification capacity: Indonesia in August 2012 and Israel in January 2013. In 2013, Singapore and Malaysia began commissioning their first terminals. Malaysia in particular is noteworthy since it has traditionally been an LNG exporter – like Indonesia and the UAE – but has turned to LNG imports to meet regional gas imbalances.

Floating Regasification: By end-2012, the floating regasification market reached **32.0 MTPA of import capacity** spread across seven countries. Israel brought Hadera Gateway online in January 2013. Utilization levels varied significantly depending on the technical characteristics of the projects' vessels and the level of local demand. The Middle East and South America had the highest levels of utilization in 2012.

Shipping Fleet: At the end of 2012, the **global LNG fleet consisted of 362 vessels** of all types, with a combined capacity of 54 bcm (vessels below 18,000 cm are not counted in the global fleet for the purposes of this report). This is more than one and a half times the size of the fleet at the end of 2006. The fleet grew by two vessels in 2012: one was delivered for use at Malaysia LNG and the other for Angola LNG. The order book for new vessels stood at 96, equivalent to 16 mmcm of new capacity. By end-2012, spot rates for modern tonnage moderated to the level of US$120,000/day after growing to US$78,000/day in 2011.

North American LNG: The boom in North American shale gas has created opportunities to export LNG from the US and Canada. With higher demand in Asia, and the perception of lower North American feedstock costs, a new export play is emerging. Over the past years, there have been numerous new project proposals that amount to **~190 MTPA of potential capacity**. However, there are a variety of political and commercial risks that will limit output from the region.

LNG as Transport Fuel: LNG use as a transportation fuel is marginal at this time. However, the divergence of natural gas and oil prices has created an opportunity for increased use. Forthcoming changes to emission standards in the global shipping industry will also boost LNG's potential in the bunker fuel market. Even with these drivers, commitment of infrastructure investment may dictate LNG's penetration rate in the transport sector.

Key:

MT = million tonnes	MTPA = million tonnes per annum	cm = cubic meters
mcm = thousand cubic meters	mmcm = million cubic meters	bcm = billion cubic meters
tcm = trillion cubic meters	mmBtu = million British thermal units	tcf = trillion cubic feet

3. LNG Imports, Exports and Prices

After 30 consecutive years of growth LNG trade fell in 2012. Despite the decline in traded volumes vis-à-vis 2011, LNG trade has increased by 36% during the past 5 years. This is largely a result of growing demand in established markets as well as new demand from emerging markets. Since 2007, nine new countries began consuming LNG. At the same time, the differential between oil-linked LNG prices and liquid market gas prices has created new opportunities and challenges for the industry.

The continued shutdown of all but 2 nuclear power facilities in Japan combined with rapid LNG demand growth in emerging markets in Asia and South America and economic slowdown in European economies resulted in LNG cargo diversions away from Europe in 2012. As a result, Europe experienced a reduction in LNG imports which was offset by increased coal consumption for power generation and increased pipeline gas imports from Norway.

3.1. OVERVIEW

237.7 MT
Global trade in 2012, first annual decline in 30 years

Global LNG flows fell by 1.6% from 241.5 MT in 2011 to 237.7 MT in 2012. The contraction was largely driven by supply-side issues in Southeast Asia (Indonesia and Malaysia) and domestic and political challenges in MENA (Egypt, Libya and Yemen). Qatar and Nigeria were able to ramp up production to offset somewhat for these losses. On the demand side, the growth in Japanese demand (+8.5 MT relative to 2011) was largely offset by cargoes diverted away from the UK (-8.2 MT). Elsewhere in Europe, LNG consumption fell since pipeline gas was more affordable and North American coal imports helped meet power needs.

No new exporters joined the LNG trade in 2012, though France and Portugal joined the group of re-exporters. Only 3.73 MTPA of effective capacity was added in 2012 since the 4.3 MTPA Pluto LNG project in Australia came online in April. The Marsa el Braga facility in Libya failed to deliver a single cargo after the civil war in 2011, and is assumed de-commissioned. Angola is expected to join the club of LNG exporters in 2013. New capacity is also expected online in Algeria, but this will offset older capacity that will be de-commissioned.
The number and geographic reach of countries that have started importing LNG over the past four years has grown tremendously. From end 2008 to 2012, Brazil, Canada, Chile, Kuwait, Indonesia, the Netherlands, Thailand, and the United Arab Emirates have begun importing LNG joining the existing 18 importers. Thus far in 2013, Israel and Singapore began receiving commercial cargoes and Malaysia has received a commissioning cargo. Many of these countries were not considered to be potential LNG importers a decade ago – and the United States, which was then expected to be the largest LNG import market by now, has seen imports slow to a trickle. These changes reflect the flexibility of the LNG value chain..

Changes in regional demand patterns and the emergence of so many new importers created a large swing in import patterns in 2012 relative to 2011. Seven countries (UK, France, Spain, US, Belgium, Italy, and Canada) saw imports fall by 1.0 MT or more, whereas six countries saw imports increase by 1.0 MT or more (Japan, Brazil, China, India, Turkey, and South Korea).

In spite of increased interregional trade, there is still no "global" LNG market with a single price structure. Rather, there are strong regional LNG supply and demand dynamics. But the increasing prevalence of divertible LNG contracts and the emergence of portfolio traders together facilitate greater inter-basin trade.

In some countries – such as Japan and South Korea – LNG is used to meet the entire gas needs. However, many

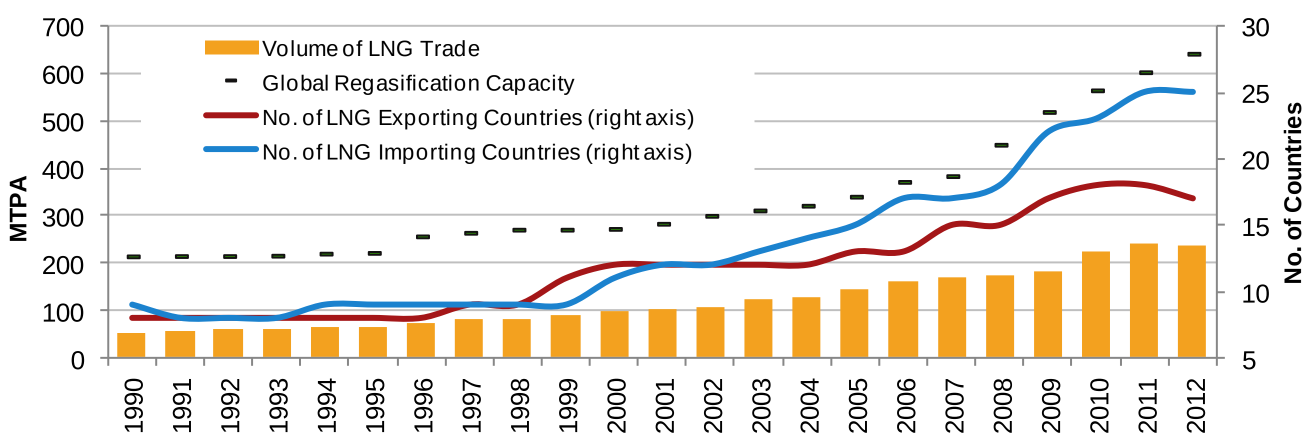


Figure 3.1: LNG Trade Volumes, 1980-2012

Source: IEA, PFC Energy

countries use LNG to fill the gap between domestic energy supply and demand imbalances.

3.2. LNG EXPORTS BY COUNTRY

By the end of 2012, 17 countries were exporting LNG, one less than 2011. Libya ceased to export LNG in 2012 after the country's civil war. In addition, six countries – Belgium, Brazil, France, Portugal, Spain and the United States – re-exported LNG in 2012. (Mexico had previously re-exported volumes in 2011.)

Qatar is by far the largest LNG exporter. In 2012, the country supplied 77.4 MT of LNG to the market – nearly one third (32.6%) of global supply. Qatar (+1.9 MT), Australia (+1.6 MT) and Nigeria (+1.2 MT) contributed 75.6% of the project specific increases in supply during 2012. Although Australia's increase can be predominantly explained by the addition of a new project (Pluto LNG), Nigeria and Qatar ramped up production to plateau and were able to satisfy strong Asia-Pacific demand during the first half of 2012. Indonesia saw the largest dip in supply due to feedstock issues at the Mahakam Block. Malaysia also was down but this was attributed to a fire at one of its liquefaction facilities in July 2012. Various MENA countries experienced political unrest and/or greater diversions to the domestic market.

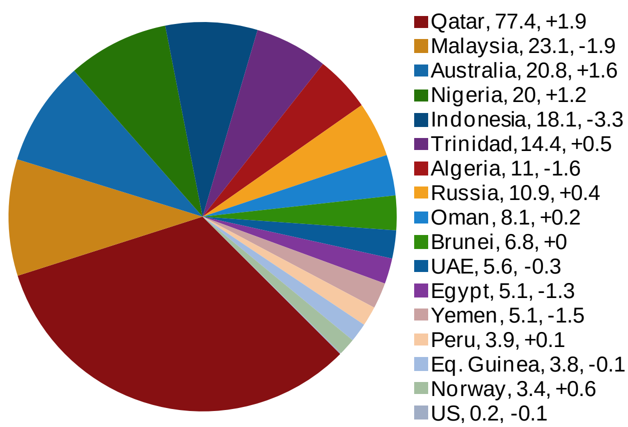


Figure 3.2: LNG Exports by Country: 2012 Exports & Incremental Change Relative to 2011 (in MTPA)

Sources: Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

Beyond the dramatic rise in LNG exports from Qatar in the last decade, several new exporters have joined the market increasing the supply diversity. Moreover, legacy suppliers have increased capacity by developing new projects. Regionally, the Middle East outpaced Asia-Pacific in total export volumes in 2006 and has since continued to supply more volumes to the market and gain market share.

In 2012, the Middle East produced 112.7 MT and Asia-Pacific 80.8 MTPA. This trend is likely to reverse in the coming decade as new Australian projects are expected to come on-stream post-2015 and prospects for growth in LNG exports turn to newer regions such as North America and East Africa.

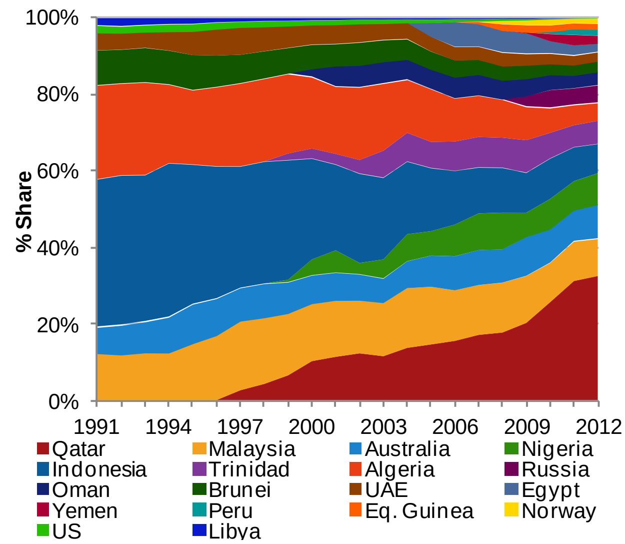


Figure 3.3: Share of Global LNG Exports by Country, 1991-2012

Sources: Cedigaz, GIIGNL, Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

The Middle East and North Africa region faces many issues which impact development from country to country; these include rising domestic demand, regulatory or energy policy clarity, economic and political stability, sanctions (in the case of Iran), and more challenging geological structures and uncertainties related to reserves.

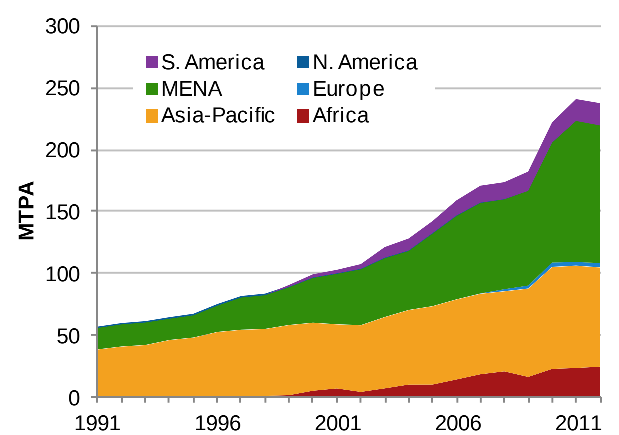


Figure 3.4: LNG Exports by Region, 1991-2012

Sources: Cedigaz, GIIGNL, Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

Re-exports have been growing rapidly over the past three years and reached 3.5 MT in 2012. In 2012, growth in re-exports was mainly attributed to strong LNG demand in South America and weaker demand in Europe prompted Belgium, France, Portugal, and Spain to re-export to higher-paying markets such as Argentina and Brazil.

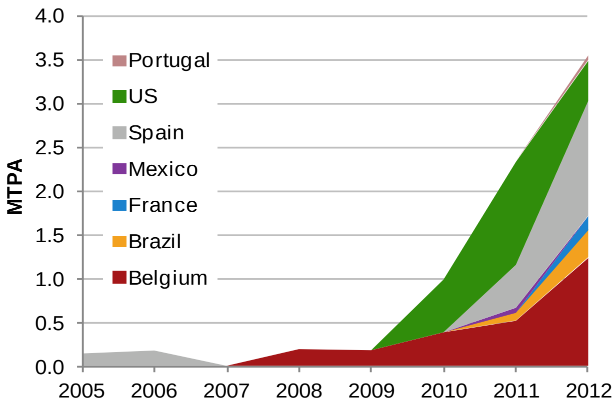


Figure 3.5: Re-Exports by Country, 2005-2012

Sources: Cedigaz, GIIGNL, Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

3.3. LNG IMPORTS BY COUNTRY

Japan and Korea are the world's dominant LNG importers, consuming 52% of LNG supplied to the market in 2012.

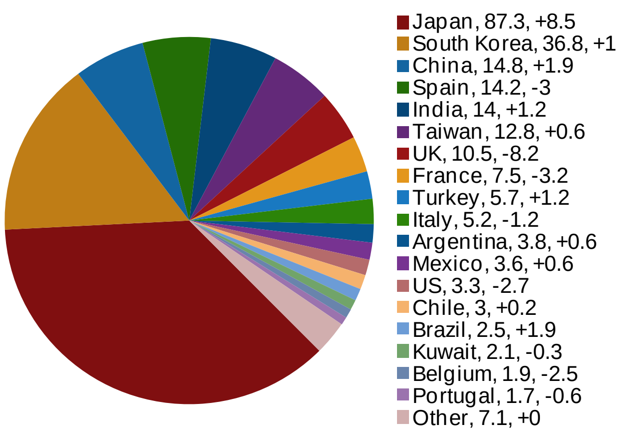


Figure 3.6: LNG Imports by Country: 2012 Imports & Incremental Change Relative to 2011 (in MTPA)

"Other" includes Canada, UAE, Greece, Thailand, Puerto Rico, Dominican Republic, Indonesia, and the Netherlands

Sources: Waterborne LNG, US DOE, PFC Energy Global LNG Service

This figure was 4% higher than 2011 volumes due to even higher demand for LNG in Japan as most of the country's nuclear reactors are still offline following the March 2011 Great Eastern Earthquake. Nuclear generation, which previously accounted for 30% of Japan's power supply, fell 43% in 2011 and another 89% in 2012. In the second half of 2012, nuclear power made up just 3% of electricity supply. These nuclear outages prompted a 12% increase in LNG imports in 2011 and an 11% increase in 2012. As a result, LNG imports have become increasingly expensive and buyers have bolstered marketing activities to secure LNG supply. LNG has not made up the nuclear generation shortfall alone, however, crude and HFO purchases by Japanese utilities have increased substantially. This has solely been an emergency response to boost power generation; the country is not expected to continue to have a high reliance on oil-fired power plants, many of which are aging and inefficient, once nuclear plants restart.

Asian countries are by far the most dependent on LNG imports to meet gas demand, more than double the share in Latin America and Europe. The two largest importers – Japan and Korea – rely almost entirely on LNG. China and India are two countries with tremendous LNG growth trajectories, but currently LNG is less than 40% of total gas consumption. Mexico consumes the most LNG in North America, but the region as a whole relies marginally on LNG for gas needs.

However within regions, there is significant variation in the dependence on LNG to fulfil gas demand. This is exceptionally evident in Europe where Spain uses LNG to meet 60% of gas demand, whereas Italy is only 10% dependent.

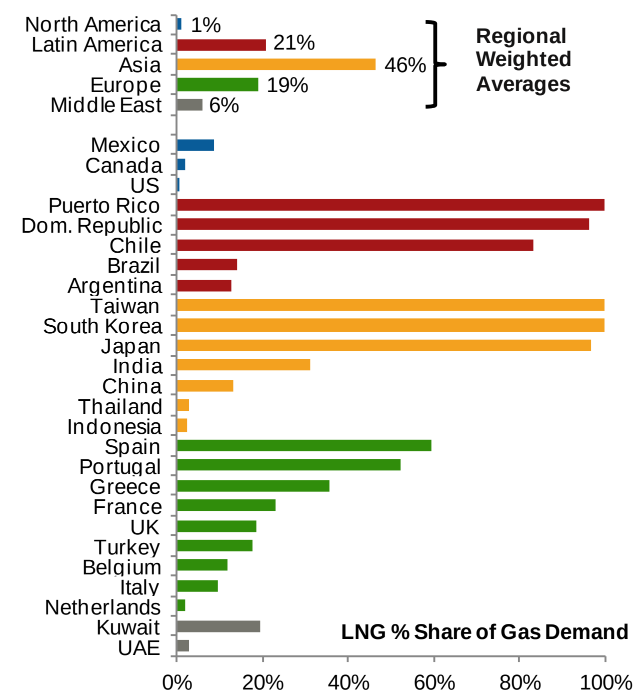


Figure 3.7: The Role of LNG in Gas Markets in 2012

Sources: IEA, Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

Table 3.1: LNG TRADE VOLUME BETWEEN COUNTRIES, 2012 (in MTPA)

	Algeria	Egypt	Eq. Guinea	Nigeria	Norway	Peru	Trinidad	UAE	Oman	Qatar	Yemen	Australia	Brunei	US	Indonesia	Malaysia	Russia	Reexports Received	Reexports Loaded	2012 Net Imports	2011 Net Imports	2010 Net Imports
Belgium	-	-	-	-	-	-	-	-	-	3.15	-	-	-	-	-	-	-	-	(1.24)	1.91	4.45	4.52
France	3.15	0.69	-	2.25	0.20	-	-	-	-	1.35	-	-	-	-	-	-	-	-	(0.16)	7.48	10.68	10.51
Greece	0.56	0.12	0.06	0.06	0.20	-	-	-	-	-	-	-	-	-	-	-	-	0.07	-	1.07	0.95	0.92
Italy	0.72	0.12	-	-	0.06	-	-	-	-	4.24	-	-	-	-	-	-	-	0.08	-	5.23	6.43	6.66
Netherlands	0.06	-	-	0.05	0.44	-	0.06	-	-	-	-	-	-	-	-	-	-	-	-	0.61	0.56	-
Portugal	-	0.13	-	1.25	-	-	0.06	-	-	0.18	-	-	-	-	-	-	-	0.09	(0.05)	1.66	2.21	2.25
Spain	2.66	0.48	-	3.93	1.22	1.94	1.81	-	-	2.98	-	-	-	-	-	-	-	0.51	(1.31)	14.22	17.16	20.28
Turkey	3.10	0.39	-	1.05	0.12	-	-	-	-	0.92	-	-	-	-	-	-	-	0.16	-	5.74	4.58	5.93
UK	0.06	0.06	-	0.13	-	-	-	-	-	10.21	-	-	-	-	-	-	-	-	-	10.45	18.63	14.17
Europe	10.30	1.99	0.06	8.72	2.24	1.94	1.93	-	-	23.02	-	-	-	-	-	-	-	0.92	(2.76)	48.37	65.66	65.23
Argentina	-	0.06	-	-	0.18	-	2.72	-	-	0.06	-	-	-	-	-	-	-	0.80	-	3.82	3.19	1.28
Brazil	-	-	-	0.30	0.12	-	1.02	-	-	0.89	-	-	-	-	-	-	-	0.51	(0.32)	2.52	0.62	1.98
Chile	-	0.19	0.27	-	0.06	-	2.26	-	-	-	0.25	-	-	-	-	-	-	-	-	3.03	2.80	2.21
Dominican Republic	-	-	-	-	-	-	0.84	-	-	0.13	-	-	-	-	-	-	-	-	-	0.96	0.72	0.53
Mexico	-	-	-	0.78	-	0.89	0.12	-	-	1.26	0.26	-	-	-	0.25	-	-	-	-	3.55	2.92	4.29
Puerto Rico	-	-	-	0.05	0.06	-	0.86	-	-	-	-	-	-	-	-	-	-	-	-	0.97	0.54	0.50
Canada	-	-	-	-	-	-	0.61	-	-	0.67	-	-	-	-	-	-	-	-	-	1.28	2.42	1.54
USA	-	0.06	-	-	0.13	-	2.33	-	-	0.70	0.41	-	-	-	-	-	-	-	(0.37)	3.26	7.11	8.87
Americas	-	0.31	0.27	1.12	0.56	0.89	10.76	-	-	3.71	0.92	-	-	-	0.25	-	-	1.30	(0.69)	19.39	20.33	21.20
China	0.06	0.30	-	0.31	-	-	0.18	-	0.13	5.04	0.53	3.69	-	-	2.27	1.88	0.38	-	-	14.77	12.84	9.46
India	0.39	0.57	-	1.42	0.00	-	-	-	-	10.89	0.40	-	-	-	-	-	-	0.31	-	13.99	12.74	9.23
Indonesia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**	-	-	-	-	-	-	-
Japan	0.16	0.98	2.86	4.70	0.36	0.77	0.27	5.53	3.92	15.68	0.30	15.92	5.95	0.19	6.23	14.37	8.31	0.75	-	87.26	78.76	70.42
South Korea	0.06	0.62	0.38	1.85	0.06	-	0.90	-	4.03	10.77	2.58	0.79	0.90	-	7.47	4.09	2.17	0.11	-	36.78	35.73	33.93
Taiwan	0.06	0.18	0.18	1.16	0.06	-	0.06	-	-	5.97	-	0.31	-	-	1.90	2.76	0.06	0.06	-	12.78	12.18	11.30
Thailand	-	-	-	0.06	-	0.29	0.05	-	-	0.18	0.40	-	-	-	-	-	-	-	-	0.98	0.72	-
Asia	0.73	2.65	3.42	9.51	0.48	1.06	1.46	5.53	8.08	48.53	4.21	20.72	6.85	0.19	17.87	23.11	10.92	1.23	-	166.56	152.97	134.35
Kuwait	-	0.12	-	0.61	0.14	-	0.18	-	-	1.00	-	0.06	-	-	-	-	-	-	-	2.11	2.42	2.07
UAE	-	-	-	-	-	-	0.06	0.04	-	1.14	-	-	-	-	-	-	-	-	-	1.24	1.18	0.12
Middle East	-	0.12	-	0.61	0.14	-	0.24	0.04	-	2.14	-	0.06	-	-	-	-	-	-	-	3.35	3.61	2.19
2012 Exports	11.03	5.08	3.75	19.95	3.41	3.89	14.40	5.57	8.08	77.41	5.13	20.78	6.85	0.19	18.12	23.11	10.92	3.45	(3.45)	**237.67**		
2011 Exports	12.59	6.42	3.89	18.75	2.86	3.76	13.94	5.85	7.90	75.49	6.65	19.19	6.84	0.33	21.43	24.99	10.49	2.33			**241.45**	
2010 Exports	14.26	7.16	3.94	17.96	3.45	1.33	15.00	5.90	8.70	57.19	4.22	19.12	6.65	0.57	23.53	22.94	10.44	0.99				**222.60**

***Note: Indonesia conducted domestic LNG trade in 2012, so this is not reflected as an international trade between countries.*
Sources: Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

Internal market dynamics have changed the trajectories of several countries over the past few years. In North America, the evolution of US shale gas production has reduced LNG import needs in not only the US, but also Canada and Mexico due to the interconnectedness of the North American grid. Europe's share of global LNG demand fell 20% in 2012 – a level not seen since 1980. In 2012 specifically, the increased competitiveness of coal, availability of renewable power and higher pipeline gas imports depressed LNG demand. In Asia, demand continues to be resilient. Most of the incremental gains in the region were a result of higher Japanese LNG demand to offset the declines in nuclear generation.

In developed and emerging markets, gas is increasingly a fuel of choice for electricity generators, provide heating and cooling, offset declining production, and support economic growth. From end 2008 to 2012, eight countries have begun importing LNG joining the existing 18 importers. Thus far in 2013, Israel and Singapore began receiving commercial cargoes and Malaysia has received a commissioning cargo.

Notably, Indonesia, Malaysia and the UAE are traditional LNG exporters but domestic demand growth and geographic issues have forced all three countries to use regasification. Although Indonesia currently sources its LNG from domestic producers, it could turn to imports from abroad by the end of the decade.

3.4. LNG INTERREGIONAL TRADE

71% of the world's LNG is consumed in the Asia-Pacific.

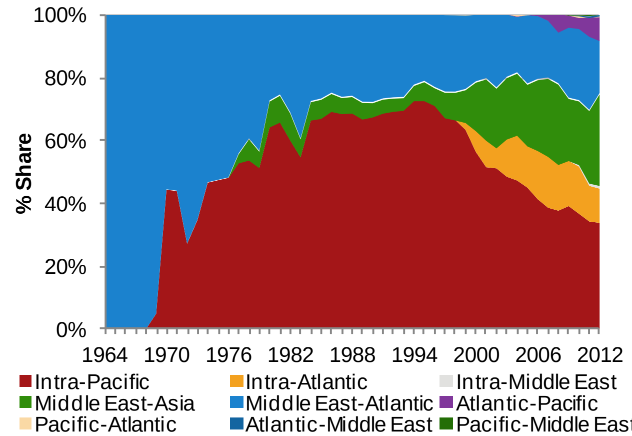


Figure 3.9: Inter-Basin Trade Flows 1964-2012

Source: Cedigaz, GIIGNL, Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

The Middle East to Pacific trade flow has increased the most between 2000 to 2012 growing from 15.3 MT to 54.3 MT. Asian countries consumed 166.6 MT of LNG in 2012 or an 11% increase from 2011. This was largely attributed to a re-distribution of cargoes: in 2012 Asia-Pacific export projects accounted for 49% of the import volumes down from 54% in 2011 whereas MENA contributed 42% of Asian demand in 2012 versus 37% in 2011.

The increase in MENA volumes to Asia-Pacific was facilitated by the divertibility of many European supply combined with the LNG price spread between Asia and Europe resulting in Qatari volumes re-directed eastward.

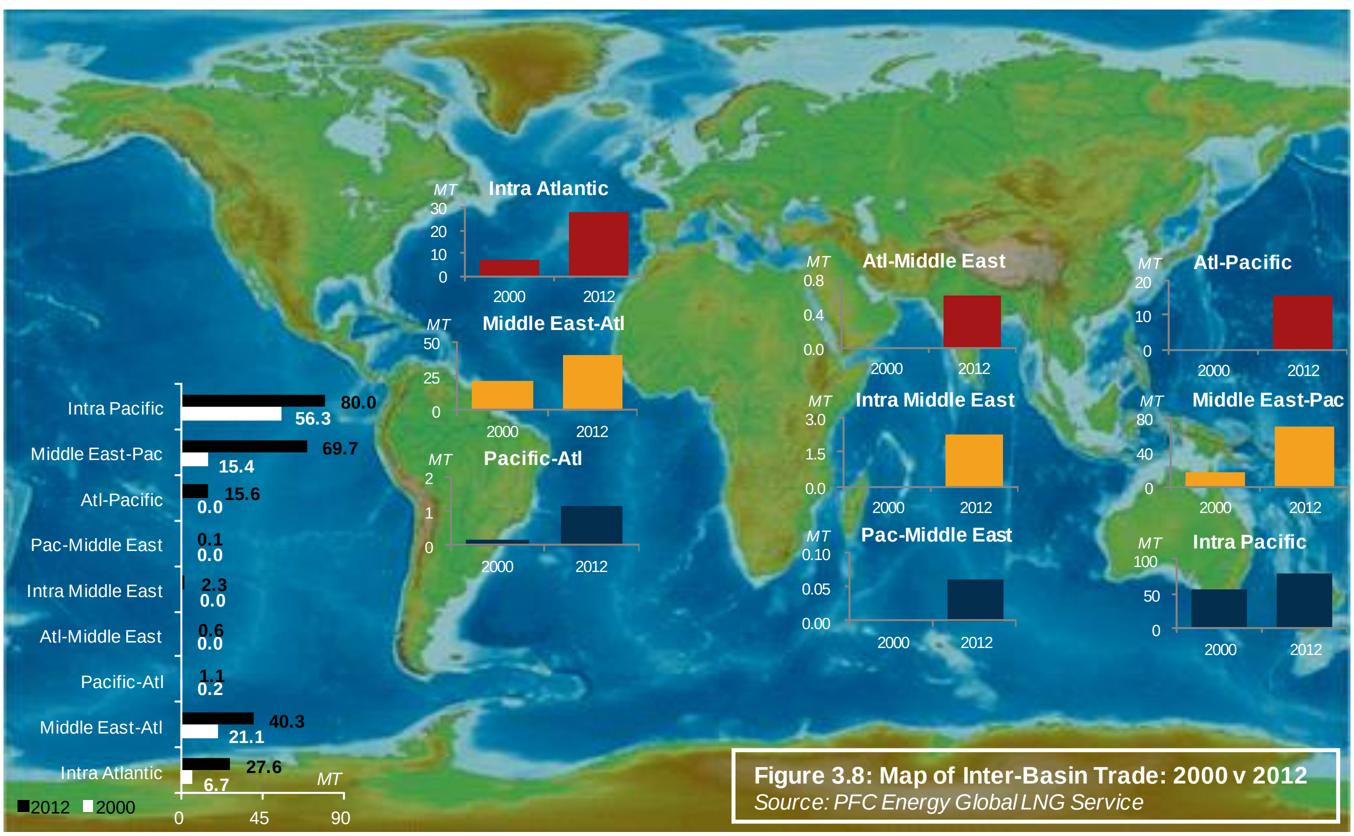


Figure 3.8: Map of Inter-Basin Trade: 2000 v 2012

Source: PFC Energy Global LNG Service

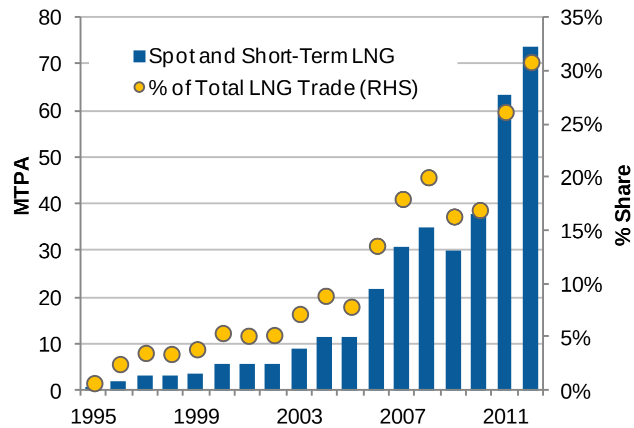


Figure 3.10: Spot & Short-Term Volumes, 1995-2012

Sources: Sources: Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

Another re-direction in trade was volumes destined for the North American market that were diverted to South American markets. In 2012, South America surpassed North American imports volumetrically for the first time. In 2012, strong Asian fundamentals and competition from coal in Europe resulted in systematic re-direction of Middle Eastern volumes from Europe to Asia. The emergence of new LNG plays in the US, Canada, and East Africa has the potential to alter the current supply position of the market in this decade or later.

Importing Region / *Exporting Region*	Europe	Asia Pacific	Middle East	North America	South America	Re-exports	**Total**
Africa	8.7	12.9	0.6	0.8	0.6	0.0	**23.7**
Asia-Pacific	0.0	79.8	0.1	1.1	0.0	0.0	**81.0**
Europe	2.3	0.5	0.1	0.2	0.4	(2.8)	**0.7**
MENA	35.3	69.7	2.3	3.4	1.6	0.0	**112.3**
N. America	0.0	0.2	0.0	0.0	0.0	(0.4)	**(0.2)**
S. America	3.9	2.2	0.2	3.9	6.8	(0.3)	**16.8**
Re-exports	0.9	1.2	0.0	0.0	1.3	0.0	**3.5**
Total	**51.1**	**166.6**	**3.4**	**9.4**	**10.7**	**(3.5)**	**237.7**

Table 3.2: LNG Trade Between Basins, 2012, MT

Sources: Waterborne LNG Reports, EIA, DOE, PFC Energy Global LNG Service.

3.5. LNG SPOT AND SHORT-TERM MARKET[1]

Traditionally, LNG has been delivered under long-term arrangements between buyers and sellers and was only marginally traded on a spot and short-term basis.

Before 2000, the spot and short-term market was marginal, accounting for less than 5% of volumes traded. By 2005, its share had grown to 8%, before experiencing another step change in 2006. Between 2007 and 2010, the spot and short-term market accounted for 17 to 20% of total LNG trade. In 2011 and 2012, a variety of factors have vaulted the spot and short-term market to new heights – the market reached 73.5 MTPA in 2012, or 31% of global trade. These factors include:

73.5 MT
Spot and short-term trade in 2012; 31% of total trade

- The growth in LNG contracts with destination flexibility, chiefly from the Atlantic Basin and Qatar.
- The increase in the number of exporters and importers which has increased the complexity of the trade and introduced new permutations and linkages between buyers and sellers.
- The lack of domestic production or pipeline imports in Japan, Korea and Taiwan which means that they need to resort to the spot market to cope with any sudden changes in demand (i.e. Fukushima).
- The continued disparity between prices in different basins which has made arbitrage an important and lucrative monetization strategy.
- The large growth in the LNG fleet which has allowed the industry to sustain the long-haul parts of the spot market (chiefly the trade from the Atlantic to the Pacific).
- The decline in competitiveness of gas relative to other fuels, chiefly in Europe (from the economic crisis and more recently due to the increasing competitiveness of coal) and the United States (from shale gas) that has freed up volumes to be re-directed elsewhere.
- The large increase in demand in Asia and in emerging markets (i.e. Southeast Asia and South America).

In 2012, there were an equal number of spot and short-term importers and exporters at 23 each. Compared to 2011, the number of importers stayed the same because Belgium and France did not receive spot or short-term cargoes and Mexico and Puerto Rico did. The number of exporters grew by two since Brunei exported volumes well above its contractual obligation to South Korea, Portugal and France re-exported their first cargoes, and because Mexico did not re-export in 2012.

[1] The spot and short-term market here includes cargoes not supported by a long-term (5+ years) SPA, cargoes diverted from their original or announced destination, and cargoes over and above take-or-pay commitments (upward flexibility).

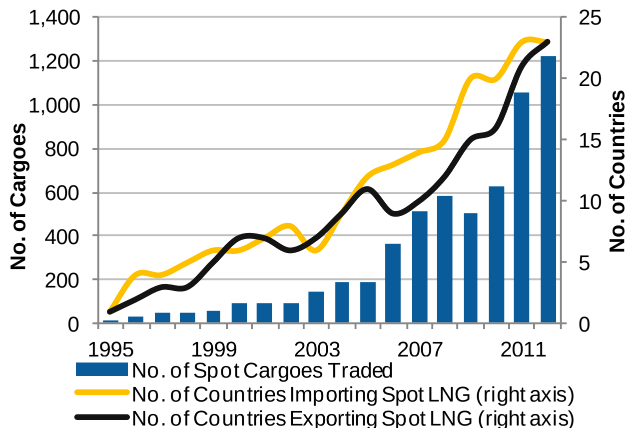


Figure 3.11: Spot and Short-Term Cargo Market Development, 1995-2012

Source: Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

3.6. LNG PRICING OVERVIEW

After three years of rising prices (except in the US), global price points were largely flat in 2012. From 2009 onwards, the market has shifted from having a demand constraint during the initial period of the Global Economic Crisis to a supply constraint in the wake of the March 2011 Fukushima disaster and due to acceleration of Asian gas demand growth.

Brent crude prices fell 31.8% between March ($125/b) and June 2012 ($95/b), which translated into a 15.7% decline in Japan's estimated import price between July and October. From August 2012 through Q1 2013, Brent has fluctuated sparingly around the $111/b level. Thus at the close of Q4 2012, the German contract price was relatively flat, owing to the greater lag in the marker's oil-linkage and the presence of European hub indexing. This result was notable in the context of further renegotiations between Gazprom and European utilities that took place throughout 2012, which resulted in increased hub-indexation for multiple contracts.

The inclusion of higher levels of European hub-based indexation into the German contract price contributed to the German contract's weak performance relative to the purely oil-linked JCC contract in 2012. This in turn added momentum to the arguments of European buyers, who see the greater inclusion of hub-based pricing as a critical solution to lowering their gas procurement cost. The 2H 2012 performance of NBP – Europe's most liquid hub – offered an important insight regarding the vulnerabilities of this pro-hub argument. NBP rallied 24% from seasonally-driven low of $8.53/MMBtu in August to $10.58/MMBtu in December, exposing the hub-based system's potential for volatility. Moving into Q1 2013, NBP's gains to the $13/MMBtu level also hints at the possibility that hub-based prices could regularly touch points much closer to oil-linked prices in the not too distant future.

Henry Hub sustained a slight recovery during the second half of 2012 closing the year at $3.34/MMBtu in December. The market continues to be bearish on the price outlook with current futures prices not consistently surpassing the $4.50/MMBtu mark until beyond 2016. Although rig counts continued to wane in 2012, gas production proved remarkably stubborn. Supply was supported by the sustained performance of top-tier wells, as rigs removed from the system had been focused on wells of inferior productivity. Temperate weather conditions ultimately moderated the call on gas-from-storage in Q4 2012, and this continued into Q1 2013.

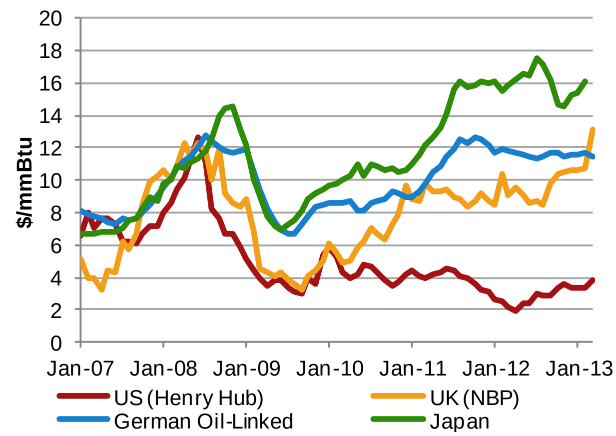


Figure 3.12: Monthly Global Gas Prices, 2007-Q1 2013

Sources: Sources: Cedigaz, GIIGNL, Waterborne LNG Reports, US DOE, PFC Energy Global LNG Service

Looking Ahead:

The LNG market will continue to be supply constrained at least until 2015: *Few projects are expected to come online in the next few years – Angola LNG, PNG LNG, QCLNG T1, and two small Indonesian projects will add incremental capacity whereas new Algerian trains will offset decommissioning capacity. Qatar already produced at nameplate capacity in 2012, and few other projects have room to boost utilization if Southeast Asian and North African projects continue to decline. Between 2015 and 2017, a slew of new Australian projects will come online to meet rising demand in Asia.*

Will there be a change in the willingness to pay for LNG?: *While power sector gas demand will continue to drive the regional redistributions of LNG flows in future quarters, the anticipated supply constraint during 2013 and 2014 may force a number of markets to take a more critical look at the issue of import cost, subsidies, and pricing. In tandem with a tight supply picture, each market's ability and willingness to pay for LNG and their relative shares of long-term vs. spot supply, may require additional attention. Given the economics of small-scale LNG, this emerging tranche of demand may also demonstrate willingness to pay high prices for new supply.*

Smaller LNG consumers continue to collectively rival top importers: *In 2013 and 2014, four more markets will begin importing – Israel, Malaysia, Singapore, and Lithuania. With the addition of these markets, there will be 15 new markets that did not import before 2005.*

Short-term volumes to become more attractive: *Japan's nuclear situation will be the major determinant of spot and short-term volumes over the next couple of years. Thus far only two nuclear reactors are back online, resulting in a major power generation gap that has been mostly been made up for by LNG. If European LNG demand continues to be weak, Asian and South American markets have proved a willingness to pay for more expensive cargoes above their long-term contracts.*

Storage Tanks at Yemen LNG, Balhaf, Yemen

4. Liquefaction Plants

Qatar holds more than 27% of global liquefaction capacity. The majority of near-term growth in liquefaction capacity is expected from Australia, though considerable momentum has built up around projects in North America and other frontier regions.

After the commissioning of its final mega-train in early 2011, Qatar's role as the driver of liquefaction capacity growth in recent years has faded. Taking its place is Australia, where projects currently under construction account for 64% of all projects that have reached FID – representing 62 MTPA of capacity. The expansion of shale gas production in North America has reversed the LNG outlook for the continent and led to a surge in the number of proposed liquefaction projects, though most are less advanced than projects in Australia. Of the 508 MTPA of proposed pre-FID projects, 43% are in the United States and 25% are in Canada; although some of these projects are expected to materialize, it is likely that a significant number will not be built. New gas discoveries in East Africa and Eastern Mediterranean have also spurred proposals, but considerable risk abounds these untested regions.

4.1. OVERVIEW

At the end of 2012, global nameplate liquefaction capacity stood at 280.9 MTPA from 92 trains in 17 countries[2]. Only one project was commissioned in 2012 – the 4.3 MTPA Pluto LNG in Australia, which came on-stream in late April.

The 5.2 MTPA Angola LNG T1 was originally intended to begin commercial operations in mid-2012, but commissioning has been delayed as the project faces technical issues. The Angolan project is the country's first and its completion will bring the number of countries with liquefaction capacity back up to 18 after the loss of capacity in Libya in 2012.

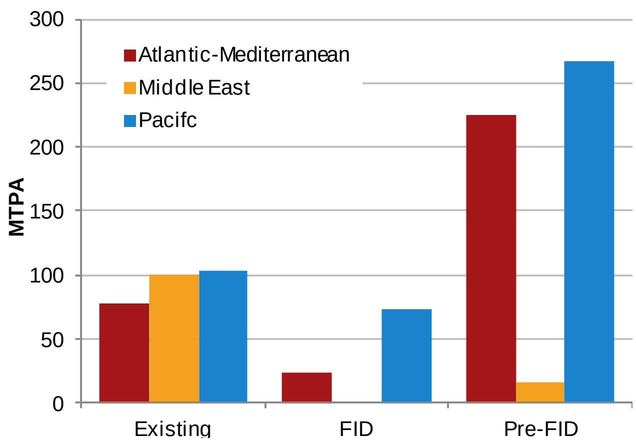


Figure 4.1: Nominal Liquefaction Capacity by Status and Region, as of Q2 2013

**Note: "FID" does not include the 10.8 MTPA announced to be under construction in Iran, nor is the project included in totals elsewhere in the document.*

Sources: PFC Energy Global LNG Service, Company Announcements

[2] *The 0.7 MTPA Marsa El Brega plant is considered decommissioned after suffering substantial damage in the country's 2011 civil war).*

Beyond the 110 MTPA of liquefaction capacity currently under construction around the world, an additional 158 MTPA of liquefaction capacity is in some stage of FEED[3], and a further 357 MTPA of capacity has been proposed. However, projects that have not yet reached FID[4] are not risked, and a large portion of them will likely never be built.

280.9 MTPA
Global liquefaction capacity at the end of 2012

Continuing the lull in new capacity experienced in 2012, only two projects are expected online in 2013: the delayed Angola LNG and the rebuild of previously destroyed trains at Algeria's Skikda GL1K, though the latter is only expected to offset capacity that will be subsequently de-commissioned.

Despite the fact that several trains have been decommissioned in recent years - the Arun LNG project in Indonesia and the Arzew/Skikda LNG project in Algeria decommissioned their oldest trains in 2010, and the retirement of other Algerian trains is likely once Arzew GL3Z and the Skikda rebuild comes online - net liquefaction capacity continues to grow as new projects are brought on-line. Although ConocoPhillips bought Marathon's stake in the Kenai LNG plant in Alaska in 2011, the company put the plant in stand-by mode in October 2012, and its export license expired in 2013.

4.2 GLOBAL LIQUEFACTION CAPACITY AND UTILIZATION[5]

Over the past four years, global liquefaction capacity grew by 12% to reach 280.9 MTPA at the end of 2012. This growth was led by a massive expansion in the Middle East as a result of the construction of major projects in Qatar, but as the final Qatari mega-train came online in 2011, the pace of expansion is expected to slow. With 110 MTPA of

[3] *Front-End Engineering and Design.*

[4] *Final Investment Decision*

[5] *Note: Throughout the document, liquefaction capacity refers to nominal capacity.*

liquefaction capacity under construction, global capacity is expected to be 366 MTPA by 2017, marking a slightly slower 27% growth.

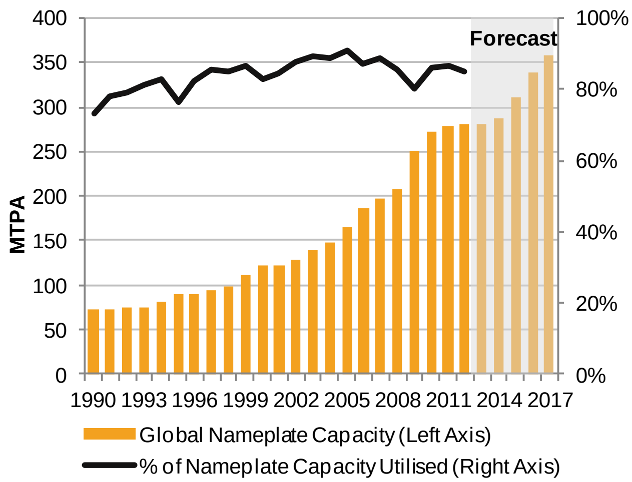


Figure 4.2: Global Liquefaction Capacity Build-Out, 1990-2017[6]

Sources: PFC Energy Global LNG Service, Company Announcements

Only one new train was commissioned in 2012 – Woodside's Pluto LNG in Australia. The 4.3 MTPA plant came online in April and has produced LNG at a higher than expected utilization rate in its first year of operations. Angola LNG was initially expected online in the first quarter of 2012, but technical difficulties delayed the project's start.

Very few projects are announced to come on-stream in 2013-15, likely resulting in a continued slowing in the growth rate before many of the Australian and Papua New Guinea projects now under construction and the first of the US projects come on-stream in the second half of the decade.

Over the past four years, global liquefaction capacity utilization was 84% on average. Although this rose to 87% in 2011, global utilization dipped back to 85% in 2012; of 17 exporting countries (not including re-exporters), 10 saw lower utilization rates. Lower liquefaction utilization levels ultimately reveal the market's vulnerability to acute issues concerning feedstock supply and disruptions to plant infrastructure, such as the fire in Malaysia or pipeline attacks in Yemen. Elsewhere, more chronic and persistent problems like feedstock maturation (Indonesia, US) and growing domestic demand requirements (Egypt, Algeria) led to utilization declines. As a result, total LNG trade declined in 2012 for the first time since the early 1980s.

Liquefaction technology has evolved over time, allowing for larger trains: the world's first liquefaction plant in Algeria had a nameplate capacity of 0.85 MTPA. In contrast, the six Qatari mega trains each have a nameplate capacity of 7.8 MTPA, helping the average nameplate capacity of trains brought on-stream from 2008-2012 to grow to 5.0 MTPA, a tremendous increase when compared to the world's earliest projects.

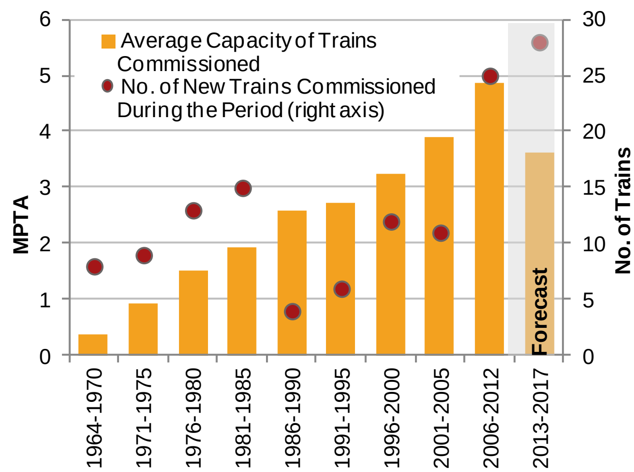


Figure 4.3: Number of Trains Commissioned vs. Average Train Capacity, 1964-2017

Sources: PFC Energy Global LNG Service, Company Announcements

As Qatar has completed construction of all of its trains, and none of the projects currently under construction intend to use the AP-X technology, it is expected that the average size of newly commissioned trains will decrease slightly over the next five years. Pluto LNG, the world's newest LNG plant, has a nameplate capacity of just 4.3 MTPA, though this may be increased with future debottlenecking.

4.3 LIQUEFACTION CAPACITY AND UTILIZATION BY COUNTRY

At the end of 2012, 17 countries had LNG export capacity – down from 18 in 2010 due to the persistent closure of the LNG plant Marsa El Brega in Libya. Well over a third of the world's capacity is held in just two countries – Qatar and Indonesia. The top five exporters (including Malaysia, Nigeria, and Australia) held 65% of capacity.

[6] *Forecast for LNG capacity to 2016 are calculated based on start dates for sanctioned projects only. As of May 2013, all sanctioned liquefaction projects had begun construction. Planned decommissioning of plants in Alaska, Algeria, and Indonesia are also included.*

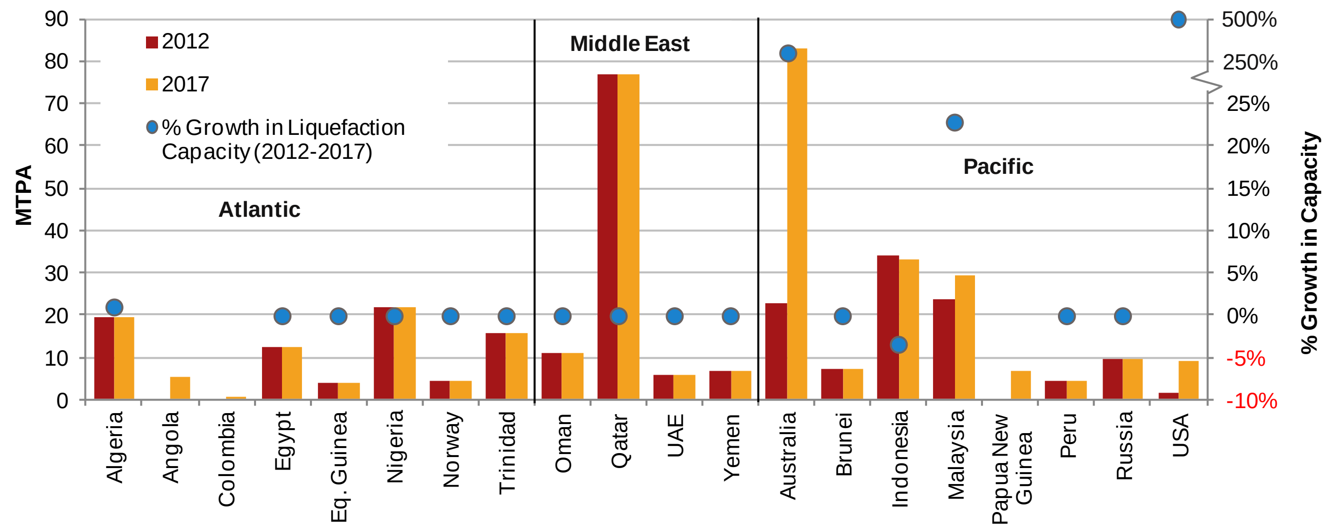


Figure 4.4: Liquefaction Capacity by Country in 2012 and 2017

Source: PFC Energy Global LNG Service, Company Announcements

In nearly all 17 countries, liquefaction capacity has remained constant or grown since 2008, though Algeria experienced a drop in capacity due to decommissioned plants in 2010 (and Libya stopped exporting entirely in 2012). Since 2008, three countries have joined the ranks of LNG exporters, with projects in Yemen, Russia (Sakhalin 2 T1-2), and Peru.

As Qatari capacity has reached its target, Australia will be the predominant source of new liquefaction capacity over the next five years. The addition of Pluto LNG pushed Australia's capacity up 22% over 2011. Seven projects are currently under construction in the country with a total nameplate capacity of 62 MTPA, which accounts for 61% of all capacity that has reached FID globally and is still in the construction phase.

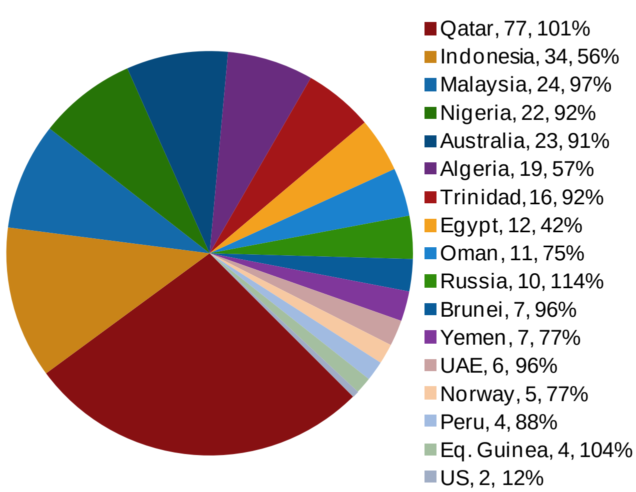


Figure 4.5: Liquefaction Capacity by Country: 2012 Capacity (MTPA) and Utilization

Sources: PFC Energy Global LNG Service

Beyond Australia, the largest expansion in LNG exporting capacity is expected from the United States, where 18 MTPA of liquefaction capacity is currently under construction. Papua New Guinea, Malaysia, and Angola account for another 17.6 MTPA, while smaller projects are under construction in Indonesia and Colombia.

A number of new large-scale projects were proposed in 2012 that are expected to add significantly to global liquefaction capacity. New liquefaction projects continue to be proposed almost monthly in the United States, with the current total standing at 43 trains comprising 180 MTPA of proposed capacity that has not yet reached FID, most of which is located in the Gulf of Mexico. For a more detailed look at the potential for North American LNG, see the North America Special Report in Section 6.

Momentum has also built up around projects in Western Canada, where 15 trains totalling 55 MTPA have been proposed; and in Tanzania and Mozambique, where huge resource estimates have led to the proposal of 6 trains (for a total of 30 MTPA), though the potential exists for major expansions.

Several LNG trains are scheduled to be decommissioned in the next five years. Indonesia's Arun LNG will continue to retire its trains as it transitions to an import facility, with the remaining trains expected offline by 2014. Algeria's Arzew and Skikda plants are expected to decommission plants as its new trains (totalling 9.2 MTPA currently under construction) come online.

4.4 LIQUEFACTION CAPACITY AND UTILIZATION BY REGION

The Pacific Basin accounted for the largest percent of liquefaction capacity in 2012 with 37%. This share will increase through 2017 as the region is host to the majority of under-construction projects; 47% of capacity expected online by 2017 is in the Pacific Basin.

Although Qatar's growth over the past decade led the Middle East to nearly equal the Pacific Basin in existing capacity, capacity in the region is likely to remain flat through 2017. The Atlantic Basin has shown only a small increase in capacity since 2007, and despite the large scale of proposed projects in the US Gulf Coast, the fairly nascent status of most of the US liquefaction proposals will lead growth to be fairly moderate through 2017 as only one US project (Sabine Pass LNG) is expected to come online.

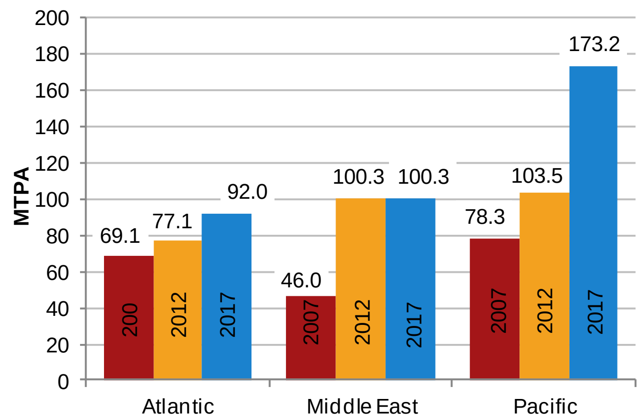


Figure 4.6: Liquefaction Capacity by Basin in 2007, 2012, and 2017

Sources: PFC Energy Global LNG Service, Company Announcements

Growth in Australian capacity is expected to outpace the rest of the world in the medium term, although a number of other Pacific Basin projects – including those in Canada, Mozambique, Tanzania, and Russia – have the potential to add significant liquefaction capacity in the Pacific Basin in the long term as well.

4.5 LIQUEFACTION PROCESSES

Seven primary liquefaction technologies were employed at the end of 2012, with a few other technologies used sporadically throughout the globe. Air Products dominates the market – its four LNG processes make up 82% of liquefaction technologies in existing projects. However, ConocoPhillips' Optimized Cascade® technology is growing in usage and makes up just under half of projects that have reached FID – all of which are located in the United States or Australia.

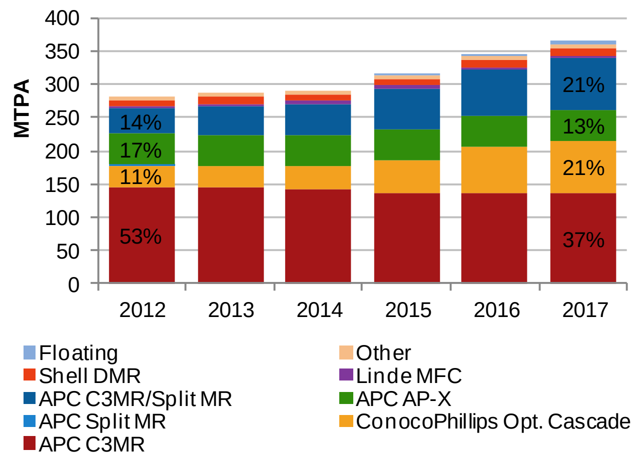


Figure 4.7: Liquefaction Capacity by Type of Technology, 2012-2017

Sources: PFC Energy Global LNG Service, Company Announcements

APC C3MR technology was the most heavily used in 2012, accounting for 65% of global nameplate liquefaction capacity. AP-X was used in the Qatari megatrains – accounting for another 17% of capacity.

Given the nature of the APC C3MR technology as a reliable and large-scale, but not massive liquefaction technology, new projects continue to announce plans to use the technology; Gorgon LNG, Papua New Guinea LNG, Donggi-Senoro LNG, and Ichthys LNG have announced plans to use established APC technologies. The APC C3MR/Split MR process is projected to grow in use most strongly out of all APC technologies – by 2017, it will have increased to 21% of the market.

4.6 NEW DEVELOPMENTS

Floating liquefaction has made much progress over the past two years; in total, 5.3 MTPA of floating liquefaction projects have reached FID. After the 3.6 MTPA Prelude LNG reached FID in 2011, two other projects reached FID in 2012: the 1.2 MTPA PETRONAS FLNG in Malaysia and the 0.5 MTPA Puerto Bahía LNG in Colombia.

Other shipping companies have unveiled plans to pursue a floating liquefaction design, but have yet to reach FID with a project. Six projects have moved forward into the engineering phase, with projects located in Canada, the United States, Malaysia, Israel, Australia, and Brazil.

Basin	2007	2012	2017 (Anticipated)	% Growth 2007-2012 (Actual)	% Growth 2012-2017 (Anticipated)
Atlantic-Mediterranean	69.1	77.1	92.0	12%	19%
Middle East	46.0	100.3	100.3	118%	0%
Pacific	78.3	103.5	173.2	32%	67%
Total capacity	***193.4***	***280.9***	***365.5***	***45%***	***30%***

Table 4.1: Liquefaction Capacity by Basin in 2007, 2012, and 2017, MTPA

Source: PFC Energy Global LNG Service, Company Announcements

Floating liquefaction is also being discussed as the development concept for more than a dozen other projects, including multiple projects in Australia, the United States Gulf of Mexico, and frontier Africa plays.

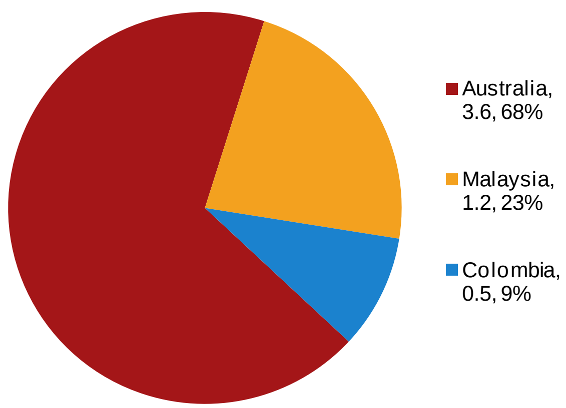


Figure 4. 8: Floating Liquefaction Capacity by Country: Under Construction Capacity in MTPA and Share of Total, as of Q2 2013

Sources: PFC Energy Global LNG Service

Perhaps the most significant change for the liquefaction industry is the emergence of new markets with a huge potential for liquefaction capacity. The US Lower 48, has been an LNG importer, but has now become a major hotspot for liquefaction proposals as domestic production has grown due to a fairly recently realized unconventional resource abundance and resultantly low natural gas prices. Further, extensive existing infrastructure makes project economics largely positive. As a result of the US shale gas boom, companies have also become interested in Western Canada, which holds a large potential for shale production. However, due to the less developed nature of unconventional plays in Canada and formative commercial and project structures, developments there are on a slower timescale. For a more detailed look at the potential for North American LNG, see the North America Special Report in Section 6.

Another new market is East Africa, where huge gas discoveries in 2010-2013 have led to the proposal of upwards of 30 MTPA of capacity in Mozambique and Tanzania, though underground resources could support upwards of 75+ MTPA. Projects in the region have the advantage of low domestic demand and geographic proximity to Asian markets. Unlike North American projects, proposals in East Africa are based on conventional gas similar to the feedstock for many existing LNG projects. However, issues specific to a frontier region make such a large build-out very difficult to achieve, such as the lack of institutional capacity and operational expertise, as well as the potential for delays resulting from governmental intervention.

In the past year, a number of new floating liquefaction projects were proposed as excitement surrounding the new technology grew. Floating liquefaction technology has the advantage of allowing the commercialization of stranded gas almost anywhere in the world, and could open up new tranches of LNG supply for commercialization. However, like any unproven technology, considerable operational risk exists. Further, projects run the risk of major cost escalation as new and unforeseen issues associated with new practices arise.

Arctic developments are another potential source of new supply, but face significant challenges. Projects are typically more expensive to develop due to the need for greater infrastructure in remote locations, while projects in Alaska or Russia face political and commercial issues.

4.7 PROJECT CAPEX

Total spending on liquefaction projects has increased dramatically over the past 10 years as a result of two major factors: new project momentum and the rising cost of materials. Several LNG projects announced cost escalations in 2012 that will see forecasted CAPEX continue to rise over the next 10 years. Average global CAPEX for liquefaction plants (excluding upstream and financial costs) increased from an average of \$399/ton for projects completed between 2001 and 2005 to \$561/ton for projects completed between 2006 and 2010.

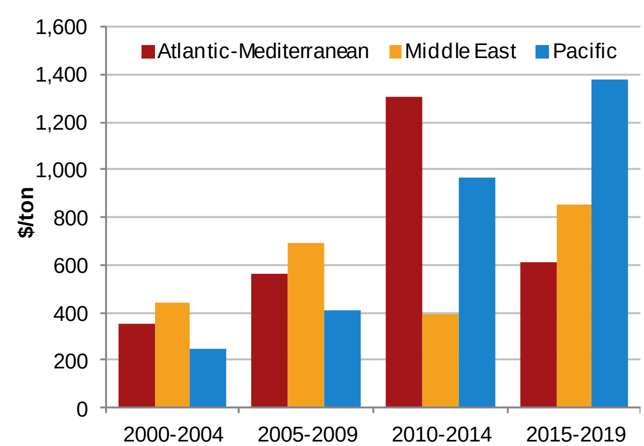


Figure 4.9: Average Project CAPEX by Basin, 2000-2019

Sources: PFC Energy Global LNG Service

Over the past ten years, projects in the Middle East had the lowest project CAPEX on a \$/ton basis due to low costs at a number of brownfield expansions, mainly in Qatar and Oman. Over the next ten years, the Atlantic Basin is expected to have the lowest project costs as a result of brownfield economics in the United States due to synergies from building on existing regasification sites.

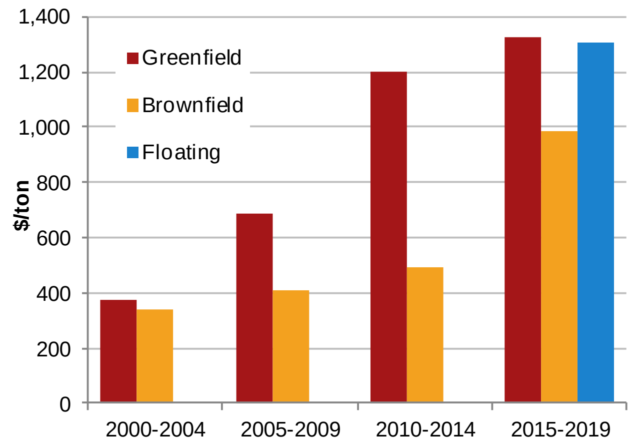


Figure 4.10: Average Liquefaction Unit Costs in $/ton (real), 1995-2019

Note: Only includes for existing and under construction projects.
Source: PFC Energy Global LNG Service

Conversely, several projects in Australia have recently announced cost escalations stem from the appreciation of the Australian dollar, rising labor costs, and weather-related project delays. As such, the Pacific Basin is expected to have the highest average unit costs over the next ten years.

4.8 SMALL-SCALE LNG

In the 1960s and 1970s, liquefaction projects between 0.25 to 1.5 MTPA were typical sizes for the industry. Only after Arun and Bontang LNG came online in the early 1980s, did the average new train size exceed 2 MTPA. More recently, some developers are coming back to small-scale projects. In the case of onshore projects, this has mainly been pursued when there were small gas reserves located in isolated areas (i.e. Skangass LNG and Sengkang LNG). Following the boom in interest for floating liquefaction, a series of projects have been proposed for offshore gas reserves that are stranded too far from shore to justify a pipeline. There are no floating liquefaction projects online, thus the technology is unproven. However three projects are under construction, of which two are small scale.

Project developers often claim that small-scale liquefaction offers cost-competitiveness on an absolute and unit-cost basis. However, there are few data points, and cost is difficult to generalize for the broader industry.

A major challenge to developing LNG projects for independent players has been a lack of company expertise in the liquefaction business. There are few cases where a company that is not a major IOC or NOC has developed a project on its own. This same challenge applies to small-scale LNG. Many companies are involved in this sphere, but not all have experience in large-scale LNG. The early slate of projects in the 1960s and 1970s was largely promoted by NOCs. Many of the new projects are operated by new entrants.

Beyond LNG exports, small-scale liquefaction has also been proposed for domestic use. Several countries around the Baltic Sea (Norway, Finland, Russia) have small-scale plants that produce LNG for use in industrial plants. China has a growing LNG-fuelled vehicle industry that has been developed mostly by Chinese companies, though IOCs have also proposed developing small-scale liquefaction to take advantage of this trend. Similarly, proposals exist in the United States to significantly ramp up domestic LNG production on a small scale for use in transportation.

Project	Country	Status	Original Capacity	Announced Start	Operator
Early Phase of LNG Industry					
Kenai LNG	US	Existing	0.9	1969	ConocoPhillips
Brunei LNG T1-5	Brunei	Existing	1.5	1972	Brunei LNG JV
Skikda - GL1K (T1-4)	Algeria	Existing	1.4	1972	Sonatrach
ADGAS LNG T1-2	UAE	Existing	1	1977	ADGAS LNG JV
Arzew - GL1Z (T1-6)	Algeria	Existing	1.1	1978	Sonatrach
Arzew - GL2Z (T1-6)	Algeria	Existing	1.1	1981	Sonatrach
Skikda - GL2K (T5-6)	Algeria	Existing	1.4	1981	Sonatrach
Recent Onshore					
Skangass LNG	Norw ay	Existing	0.3	2010	Lyse
Sengkang LNG T1	Indonesia	Construction	0.5	2013	Energy World Corp.
Sengkang LNG T2	Indonesia	Construction	0.5	2013	Energy World Corp.

Table 4.2: Small-Scale Liquefaction Export Projects

Source: PFC Energy Global LNG Service

How big will North American LNG be? *Over 250 MTPA of liquefaction capacity has been proposed in North America, with 189 MTPA alone in the United States Lower 48. However, only four trains have been sanctioned, with others stymied by energy policy (in the US) and pricing (Canada). The pace at which these projects are able to overcome their hurdles relative to other emerging liquefaction plays will be a major determinant of the eventual size of North American LNG exports.*

Will the LNG industry be able to sanction and then successfully commission projects at a rate necessary to keep pace with LNG demand growth? *The pace of project sanctioning is expected to slow significantly over the next few years – with only two projects expected in 2013 – as the world attempts to gain a handle on how large the US market can be. It is also unclear whether, once under construction, LNG supply projects will be able to successfully start up on schedule. This is currently most relevant for the Australian projects planning to begin production around mid-decade when the supply-demand balance is expected to be particularly tight.*

Will new pricing structures emerge with new export markets? *The potentially large supply of LNG from the hub-based North American market has spurred discussions of a transition away from oil-linked LNG. However, expectations of hub-linked pricing have presented problems to projects in Western Canada, where high infrastructure costs and distance from the grid have led project partners to require oil-linked prices.*

Qatargas Train 6, Ras Laffan, Qatar

5. LNG Receiving Terminals

The number of LNG importing countries is expanding as new markets turn to LNG to meet growing energy demand and to replace existing fuels. This is also the case in existing markets in Asia, but competition from domestic gas production in North America and slackening gas demand in Europe has cut demand in the Atlantic Basin, leaving a large number of regasification terminals underutilized.

Global regasification capacity continued to grow in 2012 – to 649 MTPA – despite the slight drop in global LNG trade, reflecting the increased demand for gas (and LNG) in a shifting and ever-larger number of markets. Many of these new LNG importing markets were not expected to be LNG importing markets as recently as five years ago, as an increasing number of traditional exporting countries have turned to imports to meet growing gas demand or to replace maturing domestic production or piped gas imports. The wide spread adoption of floating regasification technology has also introduced a measure of flexibility to the market, providing the ability to bring add relatively inexpensive capacity in a short amount of time. Collectively, new markets have brought online 39.2 MTPA of regasification capacity during the past four years.

5.1. OVERVIEW

The number of LNG-importing markets continues to grow as countries turn to LNG to meet gas demand; the number of countries holding regasification capacity in 2012 grew by more than 150% relative to 2002. Between 2009 and 2012, ten countries added their first regasification terminals (two of which are small-scale)[7]. Half of these new markets added capacity in just the last two years: Indonesia, the Netherlands, Thailand, Norway, and Sweden[8]. Further, Israel, Singapore, and Malaysia brought terminals online in early 2013. Notably, four out of these ten countries are located in South America (Brazil, Chile) and the Middle East (Kuwait, UAE), two non-traditional and emerging LNG importing regions.

649 MTPA

Global LNG receiving capacity at the end of 2012

5.2. RECEIVING TERMINAL CAPACITY AND UTILIZATION GLOBALLY

At the end of 2012, there were 98 existing regasification terminals in the world, for a total of 649 MTPA in regasification capacity. Out of these, fourteen terminals are small-scale and contribute a combined capacity of 4.6 MTPA. The majority of small scale terminals are located in Japan (79%), while China, Sweden, and Norway have one terminal each; the latter is largely used to receive domestic LNG. One terminal, the floating Gulf Gateway regasification terminal in the US Gulf of Mexico, was decommissioned in 2011, while the El Musel terminal in Spain was mothballed immediately after the completion of construction in 2012.

Five terminals came online in 2012, of these, only one was located in an entirely new market – the floating Nusantara terminal in the traditionally exporting market of Indonesia. The terminal came online in June and has only received cargoes from domestic LNG plants (Bontang LNG and Tangguh LNG). Three terminals were brought online in Japan to match its increased demand for LNG (Ishikari, Yoshinoura, and Joetsu). Finally, the Manzanillo terminal was brought online in Mexico. Further, two terminal expansions were completed, at Sines LNG in Portugal and Peñuelas in Puerto Rico. In total, 12.1 MTPA was added in 2012, down from a record number of start-ups totalling 54.8 MTPA in 2011.

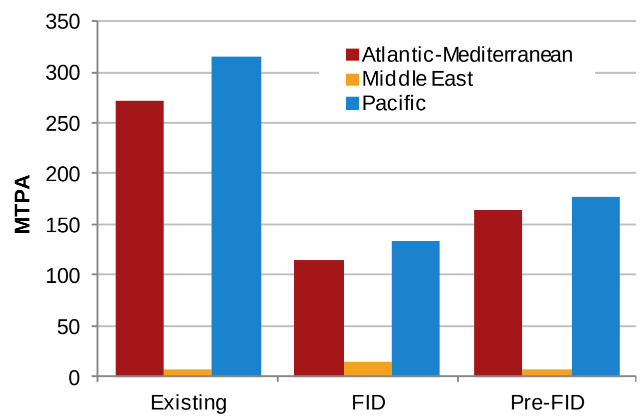


Figure 5.1: LNG Receiving Capacity by Status and Region, as of Q2 2013

Sources: PFC Energy Global LNG Service, Company Announcements

In early 2013, one terminal in India completed an expansion (Hazira) and terminals were brought online in Israel (Hadera Gateway), Singapore (Jurong Island), India (Dabhol), China (Ningbo/Zhejiang), and Malaysia (Lekas), bringing total capacity up to 663.8 MTPA from 103 terminals.

As regasification capacity grows, new markets will continue to be added, though at a slower pace than over the past few years. Out of the 29 projects under construction (23 of which are new terminals), three are

[7] *Less than 1 MTPA.*

[8] *Terminals in Norway and Sweden are small-scale and thus not reflected in global trade data in Chapter 3.*

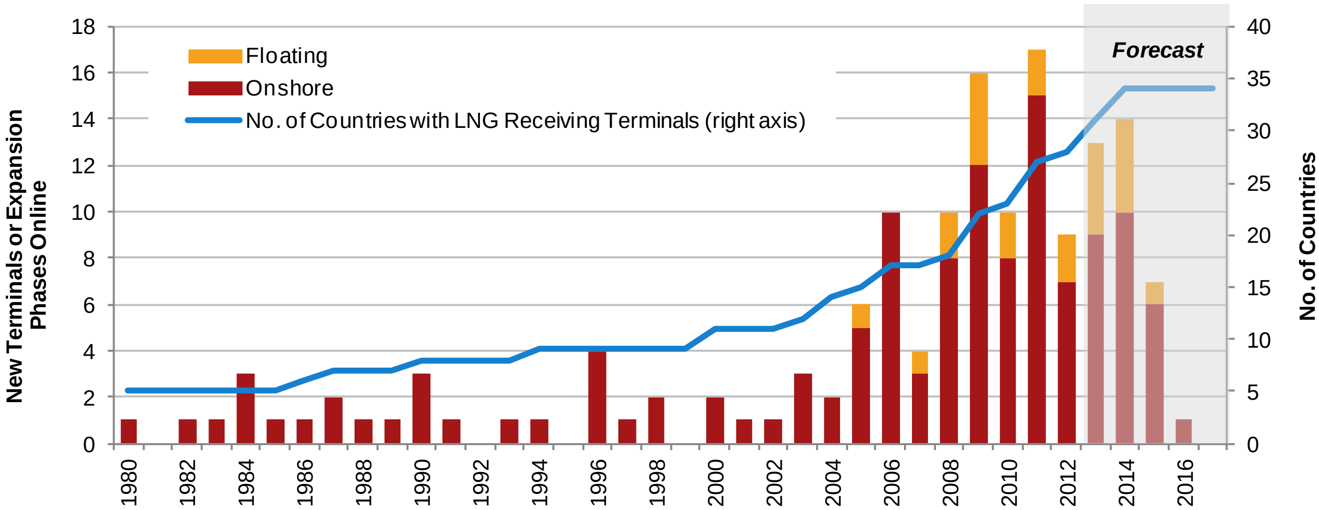


Figure 5.2: Start-Ups of LNG Receiving Terminals, 1980-2017

Source: PFC Energy Global LNG Service, Company Announcements

located in markets which have never imported LNG: Colombia, Lithuania, and Poland.

Global utilization of LNG import terminals has historically been less than 50% due to the seasonal nature of many gas markets, as well as the variations in demand worldwide. Utilization fell to 37% in 2012 both as a result of decreased LNG supply and slumping demand for LNG in Europe and North America, which left many terminals near empty.

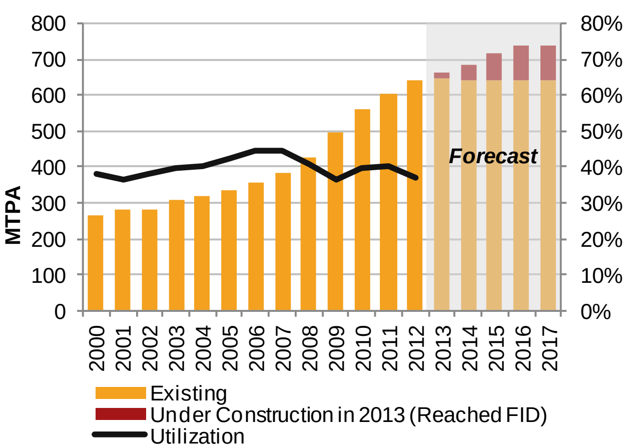


Figure 5.3: Global Receiving Terminal Capacity, 2000-2017

Sources: PFC Energy Global LNG Service, Company Announcements

As an increasing number of small to medium-sized terminals came online, the average maximum send-out capacity of regasification terminals has declined, from 8.0 bcm/yr in 2011 (5.8 MTPA) to 7.6 bcm/yr (5.6 MTPA) in April 2013. The advent of floating regasification technology has aided this shift, as the average capacity of floating terminals is only 4.7 bcm/yr (3.4 MTPA).

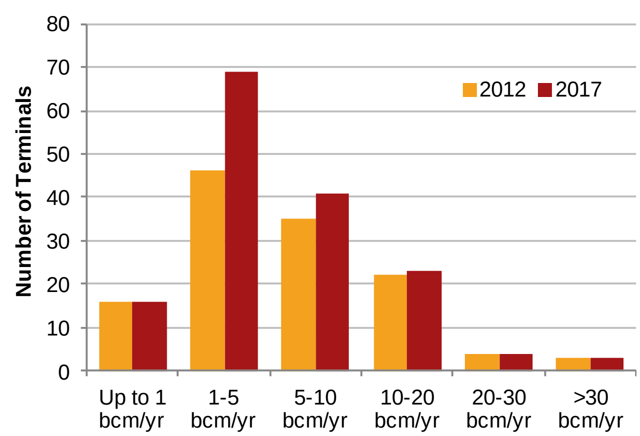


Figure 5.4: Annual Send-out Capacity of LNG Terminals in 2012 and 2017

Sources: PFC Energy Global LNG Service, Company Announcements

5.3 RECEIVING TERMINAL CAPACITY AND UTILIZATION BY COUNTRY

Although the three biggest LNG regasification capacity holders (Japan, the United States, and Korea) held well over half of global regasification capacity at the end of 2012, their share has declined since 2009, dropping from 67% to 62%. Including the United Kingdom and Spain, the top five regasification capacity markets held 74% of global capacity at the end of 2012 (down from 79% in 2009) with the remaining 26% located in 23 countries.

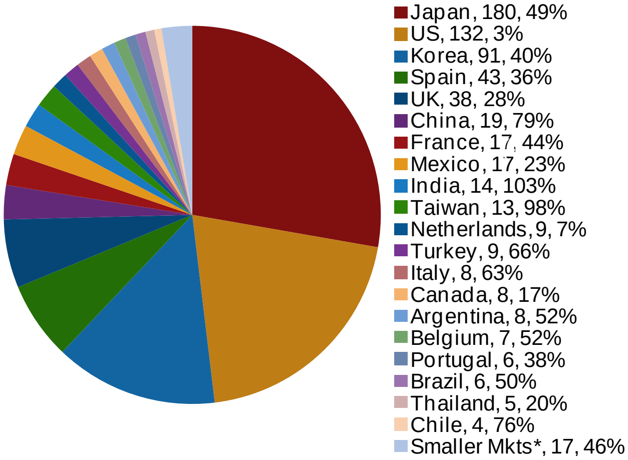


Figure 5.5: LNG Regasification Capacity by Country: 2012 Capacity (MTPA) and Utilization

Note: "Smaller Markets" includes capacity in Kuwait, Greece, Indonesia, the United Arab Emirates, Puerto Rico, Sweden and Norway. Each of these countries has less than 4 MTPA of regasification capacity.

Sources: PFC Energy Global LNG Service

China has more than quadrupled its capacity in the past five years, growing from 0.7% to 2.9% of global LNG receiving capacity. The country is still planning to greatly expand capacity to meet its growing LNG demand. In the past, Chinese operators would only be allowed to build regasification terminals if there was a long-term supply contract in place. Now, companies have started to build terminals without such contracts, as they may partially rely on spot or short-term supply.

Import capacity utilization is high in Asia, where several countries have increased LNG imports in response to the loss or decline of nuclear power generating capacity, though utilization in Japan is restricted by berthing constraints. In contrast, India operated above capacity as it faced gas supply shortages in 2012, illustrating the need for more capacity.

Terminals in the United States have been vastly underutilized (3% in 2012) due to soaring domestic production. Many terminal operators are now considering adding liquefaction capacity to take advantage of the shale gas boom. Low North American gas prices resulting from high US production have also decreased the economic rationale for LNG imports in Canada and Mexico (although certain parts of the latter are supply constrained and require LNG imports), which experienced low utilization rates as well. In Europe, where liquid markets allow for the option to procure either LNG or piped gas depending on relative prices, regasification utilization rates fell as several countries turned to piped gas. Further, gas-fired power faced increased price competition from coal and subsidized renewable power generation.

5.4 RECEIVING TERMINALS BY REGION

Historically, East Asia has held the majority (~70-80%) of the world's regasification capacity, with Europe and, to a lesser extent, North America making up the remainder. However, East Asia's share has been declining dramatically since the mid-2000s as the United States massively built up its LNG import capacity.

The emergence of new importing countries later in the decade has also led to a diversification of market shares, with additions from South America, South & Southeast Asia, and the Middle East. While LNG capacity is expected to stagnate along with demand in traditional North American and European markets, East Asia will continue to experience growth, with planned capacity additions in Japan, Korea, and especially China. Emerging markets are also expected to continue to grow, with a major expansion of regasification capacity expected from

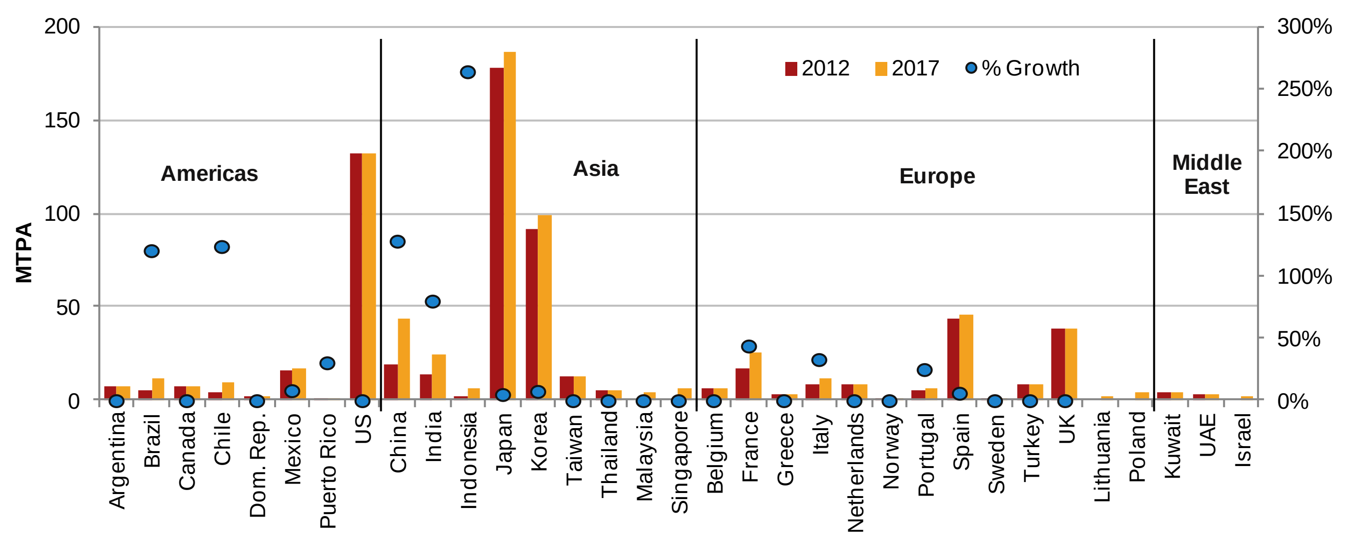


Figure 5.6: Receiving Terminal Import Capacity by Country in 2012 and 2017

Source: PFC Energy Global LNG Service, Company Announcements

South and Southeast Asia, and to a lesser extent South America and the Middle East.

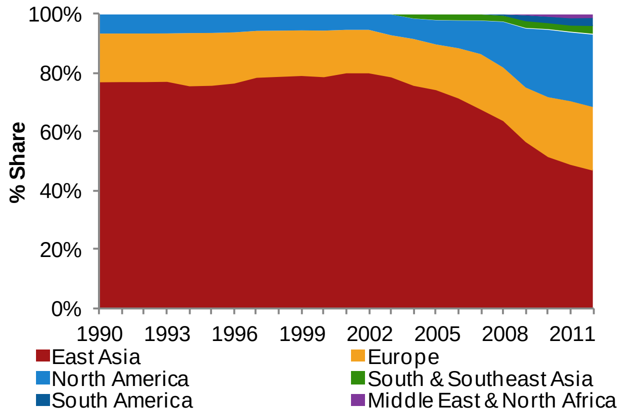


Figure 5.7: Regasification Capacity by Region, % Share of Total

Sources: PFC Energy Global LNG Service, Company Announcements

5.5 RECEIVING TERMINAL LNG STORAGE CAPACITY

At the end of Q1 2013, the world's regasification terminals had over 44 mmcm of combined LNG storage capacity. For smaller markets, the size of a country's LNG storage reflects regasification capacity fairly well. Larger markets are the general exception: the United States holds a much smaller (11%) share of total LNG storage compared to its share of the world's regasification capacity (20%) due to the country's large and well-connected non-LNG storage infrastructure. Conversely, Japan, where the gas market is highly dependent on LNG, holds a higher share (36%) of global LNG storage than regasification capacity (28%).

In 2012, 80% of storage capacity was held in just six countries; Japan and Korea made up over half of the total. China has recently joined the top tier of LNG storage capacity holders; the country brought 740 mcm of capacity onstream in 2011. More notably, China also has more than 3.3 mmcm of capacity under construction, which will more than double its current LNG storage capacity when completed.

Storage capacity is highly correlated with regasification capacity in smaller terminals. On average, terminals in the Pacific Basin have more storage per MTPA of regasification capacity than terminals in the Atlantic Basin, as Atlantic Basin gas markets tend to have more storage facilities independent of LNG terminals (like salt caverns or depleted gas fields) than Pacific Basin markets. As both regasification facilities in the Middle East are smaller floating facilities, they have low storage capacity.

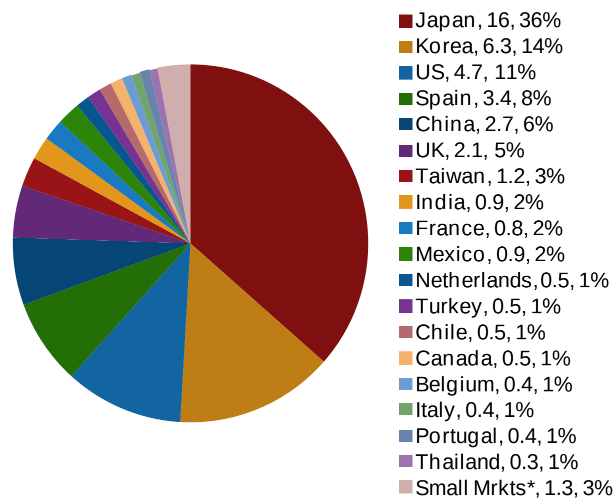


Figure 5.8: LNG Storage Tank Capacity by Country: Q2 2013 Capacity (mmcm) and % of Total as of Q2 2013

Sources: PFC Energy Global LNG Service, Company Announcements

GATE LNG, The Netherlands

Sources: PFC Energy Global LNG Service, Company

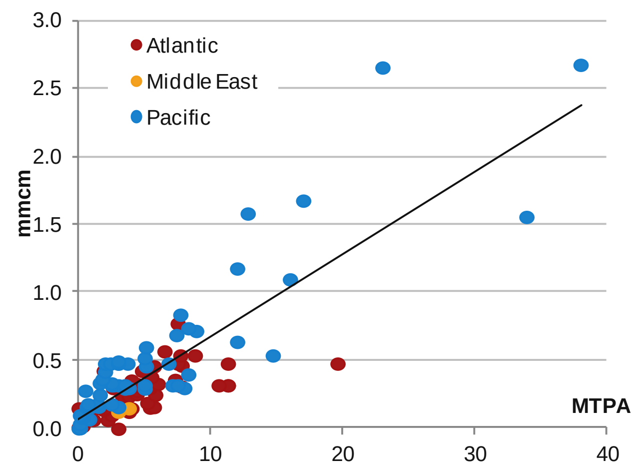


Figure 5.9: LNG Storage Capacity as a Function of Regasification Capacity, 2012

Sources: PFC Energy Global LNG Service Announcements

5.6 RECEIVING TERMINAL BERTHING CAPACITY

Roughly 60% of LNG terminals can accommodate vessels with an LNG carrying capacity of over 180,000 cubic meters. This share has doubled since 2005 as new terminals came on-stream with berthing capacities over 180,000 cm and a growing number of existing terminals are upgrading facilities to accommodate larger ships. However, as the average terminal size decreases, smaller jetties may need to be accommodated.

Recently, however, the number of terminals with conventional berthing capacity has increased, largely due to the commissioning of floating terminals, including the Nusantara terminal in Indonesia in 2012 and the Hadera Gateway terminal in Israel in early 2013.

This trend could continue as smaller floating terminals continue to be proposed as an easier way to introduce LNG to small or new markets. Floating terminals are under construction in six different countries, all of which are announced to come on-stream by 2016, with many more countries and developers studying or planning offshore terminal developments.

5.7 FLOATING AND OFFSHORE REGASIFICATION

In January 2013, the floating regasification market reached 31.7 MTPA of import capacity spread across eight different countries with the addition of Hadera Gateway in Israel. One additional offshore project exists in Italy (Adriatic LNG), but this utilizes a non-floating system. Utilization levels at these floating terminals vary significantly depending on the technical characteristics of the project's regasification vessel and the level of LNG demand in the local market. The Middle East and South America had the highest levels of import utilization at floating terminals in 2012.

Eight floating projects, totalling 20.4 MTPA of capacity, are currently under construction in six countries, including the Klaipeda LNG terminal in Lithuania, a market which has never before imported LNG. Further, nearly 100 MTPA of offshore LNG terminals have been authorized or proposed, including many in new markets.

31.7 MTPA
Floating LNG receiving capacity in Q1 2013

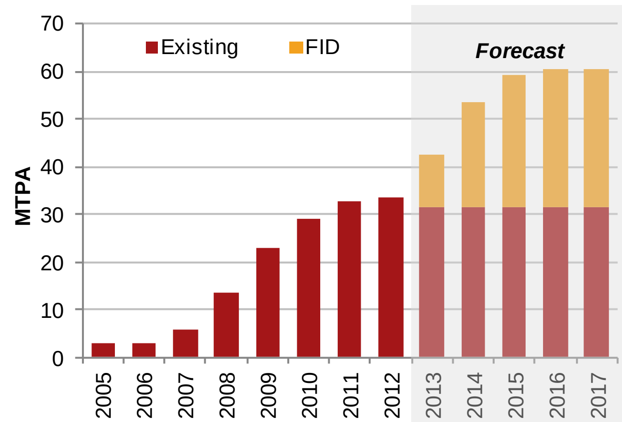


Figure 5.11: Floating Regasification Capacity by Status, 2005-2017

Sources: PFC Energy Global LNG Service, Company Announcements

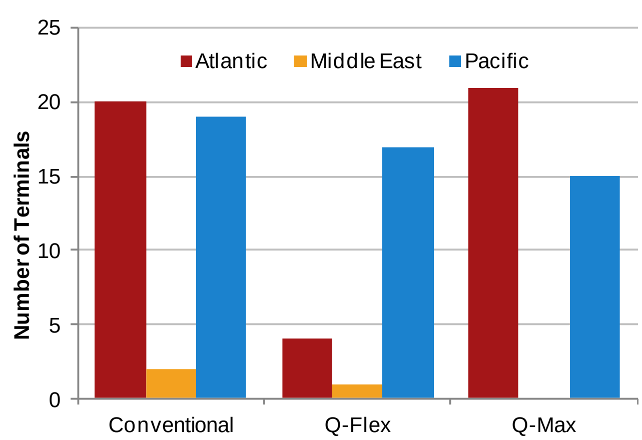


Figure 5.10: Maximum Berthing Capacity of LNG Receiving Terminals by Region, 2012[9]

Sources: PFC Energy Global LNG Service

A variety of offshore regasification concepts have been

[9] *Terminals that can receive deliveries from more than one size of vessel are only included under the largest size that they can accept.*

Country	Terminal	Reloading Capability	Storage (mcm)	No. of Jetties
Belgium	Zeebrugge	4-5 mcm/h	380	1
Brazil	Rio de Janeiro	N/A	151	1
France	FosMax LNG	1.8 mcm/h	330	1
France	Montoir	4.5 mcm/h	360	2
Portugal	Sines	N/A	390	1
Spain	Cartagena	1.8 mcm/h	587	2
Spain	Huelva	3.7 mcm/h	760	1
Spain	Mugardos	2.0 mcm/h	300	1
USA	Freeport	2.5 mcm/h*	320	1
USA	Sabine Pass	1.5 mcm/h*	800	2
USA	Cameron	0.9 mcm/h*	480	1

Table 5.1: Regasification Terminals with Reloading Capabilities in 2012

** Reloading capacity permitted by the US Department of Energy.*

Note: Some terminal operators have not publically disclosed re-loading capability information.

Sources: PFC Energy Global LNG Service

developed as the long lead time and high investment costs for land-based terminals make floating a more attractive option, particularly for new or smaller markets. The proliferation of floating systems is also a result of the lessened regulatory scrutiny due to fewer environmental impacts.

A **Floating Storage and Regasification Unit (FSRU**) is an LNG carrier with on-board regasification capability. There are two types of FSRUs: converted vessels are retrofitted LNG carriers that are permanently moored to the shore, and new-build FSRUs are constructed with the dual function of operating as a terminal or conventional LNG vessel.

A **Gravity-Based Structure (GBS)** is a submersible structure that permanently rests on the sea floor and contains integral LNG storage tanks and regasification equipment on the topside. It is a robust but costly solution and currently there are no proposals for additional GBS projects beyond the existing Adriatic LNG terminal in Italy.

Other concepts are at a conceptual stage, such as Hiload, which is a floating docking station to which an LNG carrier is able to dock via a friction-based attachment system. The LNG is regasified offshore and exported to shore via a subsea pipeline.

5.8 RECEIVING TERMINALS WITH RELOADING CAPABILITY

In 2012, eleven terminals in six countries had the capability to re-export LNG, most of which were located in Europe. Two terminals in France and one in Portugal added reloading capacity in 2012, leading to an increase in total European re-exports. In addition, the Cove Point regasification terminal in the United States has received authority to re-export cargoes, but had not done so as of March 2013.

In 2012, 74 re-exported cargoes were imported for a total of 3.5 MTPA. Belgium and Spain were the primary sources for re-exported cargoes, accounting for 71% of the total market; this represents a significant change from 2011, when the two countries accounted for just 43% of total re-exports. In the United States, re-exports fell considerably relative to 2011 (from 1.2 MTPA to 0.5 MTPA) as domestic gas prices were too low to incentivize excess initial LNG imports into the country.

5.9 PROJECT CAPEX

The total cost of regasification projects (including berthing, storage, regasification, send-out pipelines, and metering) has been trending upwards, though a much larger cost escalation is expected over the next decade. The weighted average unit cost of onshore regasification coming online in 2013 based on a three-year moving average is \$187/ton of import capacity. This is more than double the cost in 2004, and is a significant uptick from the cost in 2011 of \$145/ton.

In 2013, the weighted average unit cost of floating regasification was \$135/ton, a slight decrease from 2011 (\$148/ton) as costs of the relatively new systems went down. However, the upward trend in storage capacity for newer terminals is largely driving overall regasification costs up. Going forward, the unit cost of floating regasification is expected to hit ~\$200/ton in 2016.

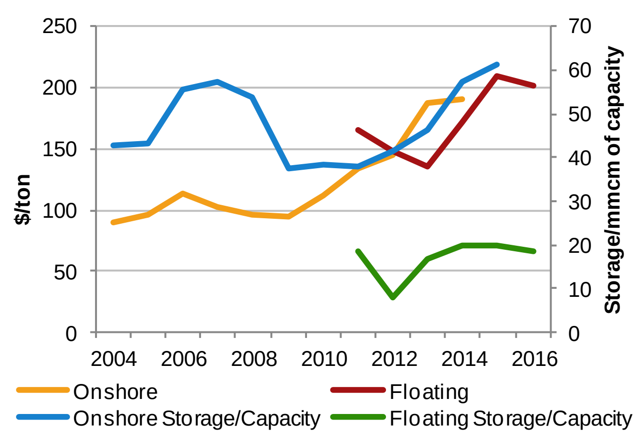


Figure 5.12: Regasification Costs based on Project Start Dates, 2004-2016

Sources: PFC Energy Global LNG Service, Company Announcements

Looking Ahead:

How quickly will the LNG import market continue to diversify? *LNG demand from emerging markets continued to grow in 2012. The number of LNG consuming countries grew as Indonesia opened its first regasification terminal. New markets took in almost 15 mmtons of LNG, a 36% increase over 2011 and a 6.2% global market share. Further, in the first half of 2013, Israel, Malaysia and Singapore began importing LNG. Over 25 new countries have proposed building regasification capacity by 2017, and the speed and ability of countries to bring these plans to fruition will greatly affect the geography of LNG demand.*

Will floating regasification continue to impact the number of LNG importers? *Several emerging markets have used floating regasification terminals as a way to quickly meet growing gas demand, and the system is proposed to be used in many more. Due to increased interest in floating, a number of floating schemes have been proposed, and there are currently two types of FSRUs, as well as one offshore type. Due to the speed and relative ease of bringing a floating import terminal online, floating regasification has been used as a tool to bridge temporary supply-demand gaps (Israel), level geographic imbalances within countries (Indonesia, Malaysia), and meet seasonal gas demand peaks (Argentina, Brazil and Kuwait).*

Will markets with floating regasification terminals turn to onshore terminals? *As more markets use floating regasification as a stopgap solution, the dependence on gas may increase resulting in further investments for long-term, onshore regasification projects. However, some markets could use floating regasification as a long-term solution also.*

How will LNG import infrastructure evolve? *Over the past few years, the average capacity of LNG import terminals has gone down, while the average cost per unit of capacity has gone up. Both of these trends are expected to continue, particularly as additional nascent LNG markets build regasification terminals without the benefit of existing infrastructure. Small-scale regasification is expected to increase in importance in the total number of terminals.*

Sabine Pass LNG Regasification Terminal, Louisiana, USA

6. LNG Carriers

The shipping market in 2012 was a story of two markets. Sustained demand for spot cargoes during the first half of 2012 would ultimately give way to supply outages at multiple LNG plants and lower demand for spot cargoes in the second half of the year. While the order book for new-build vessels increased in absolute terms, speculative orders without firm charter contracts dramatically declined in the second half of the year.

During the second half of the year, market sentiment moved beyond the post-Fukushima boom and took stock of the supply-demand reality for the first time. In particular, LNG projects and offtakers were largely ordering their own new-build tonnage rather than signing premium charter deals for the speculative tonnage already in the order book. By December 2012 and into Q1 2013, market participants were beginning to prepare themselves for greater supply than demand given the large amount of unchartered new-build supply expected to come online in 2013 and 2014.

6.1. OVERVIEW

At the end of 2012, the global LNG fleet consisted of 362 vessels of all types, with a combined capacity of 54 bcm (vessels below 18,000 cm are not counted in the global fleet for the purposes of this report). Growth in the fleet in 2012 was limited to three vessels – only two of which were above 18,000 cm. At end-2012, the order book for new vessels stood at 96 vessels, equivalent to 16 mmcm of new capacity.

362 Carriers, end-2012
Only includes those above 18,000 cm

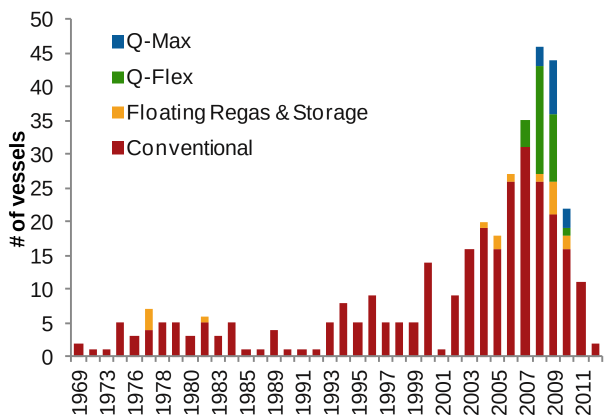


Figure 6.1: Global LNG Fleet by Year of Delivery

Sources: PFC Energy Global LNG Service

The average size of LNG carriers increased in recent years partly due to the commissioning of larger Q-Series vessels associated with Qatar. In 2012, the average capacity global fleet was approximately 148,000 cm. By contrast, the average size of vessels in the new-build order book at the end of 2012 was approximately 162,000 cm, reflecting the trend toward larger capacities for conventional vessels.

There is growing demand for alternative uses of LNG vessels, which mainly consists of Floating Storage and Regasification Unit (FSRU) vessels. Emerging market economies looking to economically stage growth in regasification infrastructure have been the biggest proponents of FSRUs to date. Many companies are also looking to develop Floating Production, Storage and Offloading (FPSO) vessels, which facilitate floating liquefaction. While three projects were under-construction in 2012, this technology remains commercially unproven.

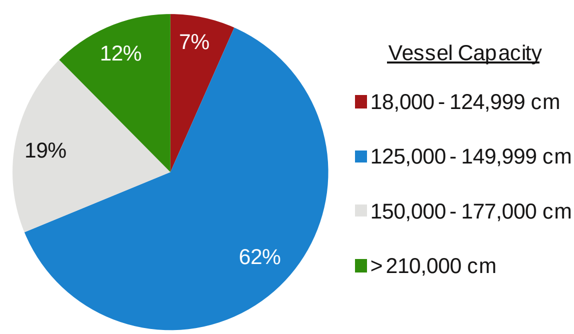


Figure 6.2: Global LNG Fleet by Capacity, 2012

Sources: PFC Energy Global LNG Service

6.2 VESSEL TYPES

The term "conventional LNG vessels" refers to the Moss-type or membrane-type vessels, which are greater than 125,000 cm and less than 180,000 cm. Non-conventional vessels include Q-Series types, which offer the largest capacities between currently available, in addition to FSRUs.

FSRUs are typically capable of both transporting LNG such as traditional LNG carriers, and additionally offer the on-board functionality of regasifying LNG, which is delivered to land via flexible pipeline connection. This onboard regasification capability eliminates the need for a traditional onshore regasification terminal, allowing the FSRU to function as a floating terminal for other conventional vessels and to deliver its own LNG cargo directly to land. Some FSRUs are permanently moored as floating regasification terminals, but the majority of the vessel type is technically capable of alternating as a floating terminal or LNG carrier at different points in a year.

Membrane-type systems continued to lead the new-build orderbook as the preferred containment option. Within the existing fleet, the alterative Moss-type containment system saw its share of the fleet slip to 31% in 2012.

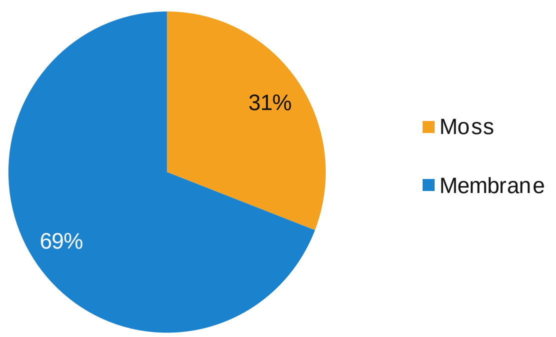


Figure 6.3: Global LNG Fleet by Containment System, 2012

Sources: PFC Energy Global LNG Service

6.3 VESSEL CAPACITY AND AGE

The size of LNG carriers ranges significantly, but more recent additions to the fleet demonstrate a bias toward vessels with larger capacities. The smallest cross-border LNG vessels, typically 18,000 cm to 40,000 cm, are mostly used to transport LNG from Southeast Asia to smaller terminals in Japan. There are also much smaller carriers – 18,000 cm and below – which are used in domestic and coastal trades, facilitating delivery of LNG to remote areas.

The most common class of LNG carrier has a capacity between 125,000-149,000 cm, representing 62% of the global fleet. The vast majority of new-build orders over the past decade were in the next capacity category, 150,000 cm to 177,000 cm. Existing vessels of this size were 19% of the current fleet, and represented the biggest source of growth for new-build orders. Finally, the largest category of LNG vessel is the Q-Series, which is composed by Q-Flex

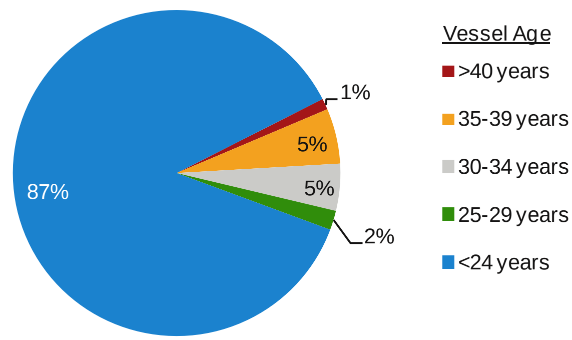


Figure 6.4: Global LNG Fleet by Age, 2012 (Number of Carriers, % of Total)

Sources: PFC Energy Global LNG Service

(210,000-217,000 cm) and Q-Max (261,700-266,000 cm).

The average age of the global LNG fleet at the end of 2012 was approximately 12 years; a reflection of the last cyclical new-build order boom that occurred in 2004. 87% of the vessels in the global fleet were under 25 years of age. In general, safety and operating economics dictate that vessel owners begin considering retiring a vessel after it reaches the age of 30, although several vessels may operate for closer to 40 years.

At the end of 2012, approximately 11% of the global fleet was over 30 years in age. The strong performance of the short-term charter market encouraged many vessel owners to postpone the retirement of older tonnage.

6.4 CHARTER MARKET

Momentum established in 2011 following the Fukushima nuclear crisis propelled charter rates in first half of 2012. Incremental demand for spot cargoes particularly in the Japanese market and in South America underpinned the short-term charter market during the first half of the year. This dynamic would ultimately change in second half of 2012 for two reasons. First, incremental demand for spot volumes

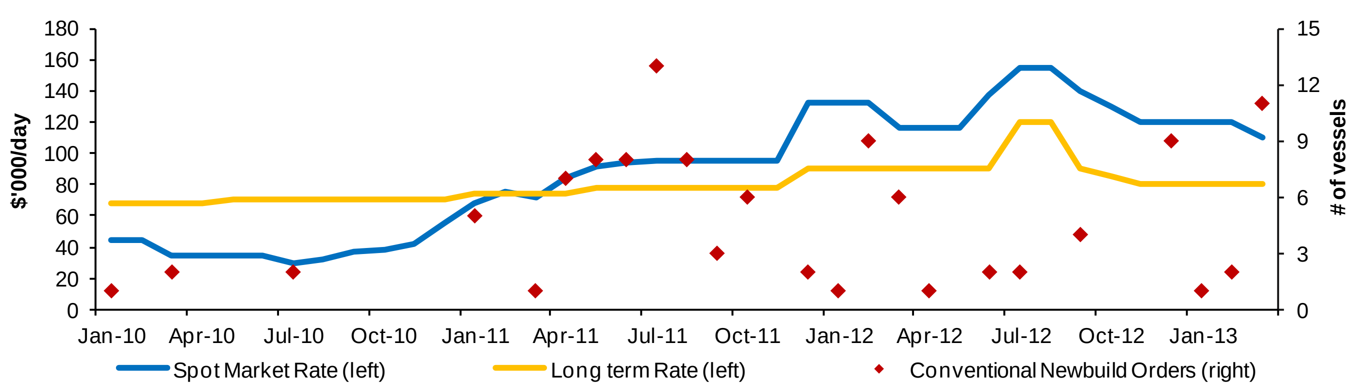


Figure 6.5: Estimated LNG Charter Rates and New-build Orders

Source: PFC Energy Global LNG Service

from markets in northwest Asia began to subside. In addition, outages at key LNG export plants would both reduce the amount of LNG supply in need of transport, and also temporarily release associated shipping assets into the short-term charter market.

By the end of 2012, spot rates for modern tonnage moderated to the level of $120,000/day and were poised to experience further weakness to the $110,000/day level in 1Q 2013. A very small number of long-term charters for modern tonnage were signed at or above the $90,000/day level, but NPV economics continued to anchor the majority of deals signed for five years or more at around $80,000/day.

6.5 FLEET AND NEW-BUILD ORDERS

During the first seven months of the 2012, shipping concerns placed orders for 27 vessels. The composition of order book during this period was a continuation of a boom in new-build orders without firm charter contracts that had occurred since the Fukushima incident. In 1H 2012, 13 out of 21 new-build orders were placed without firm charter contracts. The pace of speculative orders decreased in the final six months of the year, during which only six of 19 orders were placed on an unchartered basis. The 2012 order book totalled two FSRU orders and 38 conventional carriers.

The largest players in the market have traditionally been NOC-affiliated shipping companies. In 2011 and 2012, other players made a push into the ranks of the largest LNG carrier owners. Independent shipping companies have been quite aggressive in making orders during the post-Fukushima period. As charter markets for other forms of shipping such as dry bulk and VLCC experienced cyclical downturns, shipping companies took advantage of the counter-cyclical opportunity offered by the tightening LNG charter market.

Based on the desire of independent shipping companies to gain market share, nearly half of the 40 vessels ordered in 2012 finished the year without a charter deal. Independents placed their uncovered orders based on the belief that new sources of LNG supply and demand would entail greater demand for LNG transportation. However, the flurry new-build vessel orders associated with LNG project or LNG offtaker charters toward the end of 2012 augured poorly for this thesis. For as long as liquefaction projects and LNG offtakers with long-term horizons for shipping can take advantage of cyclically weak prices for new-build vessels, there is little incentive to pay a premium to charter existing new-build order capacity originally ordered on a speculative basis.

6.6 LIQUEFACTION AND SHIPPING CAPACITY GROWTH

During the first half of the 2000s, LNG production and shipping capacity closely tracked each other. This trend began to evolve when a boom in new-build orders driven by IOCs, independent shipping companies and Q-Series vessels associated with the new Qatari trains occurred in the middle of the decade. The increase in new shipping capacity that resulted in the second half of the decade outstripped production, creating a weak charter market for vessels unable to participate in the shipping of long-term FOB or ex-ship contracts.

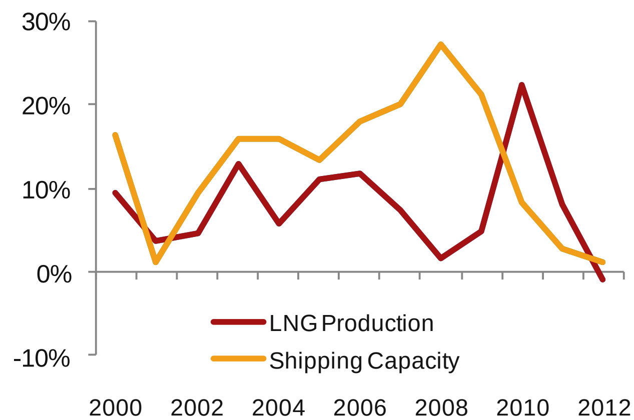


Figure 6.7: Liquefaction and Shipping Capacity Growth

Sources: PFC Energy Global LNG Service

Short-term charter rates began to strengthen starting in late

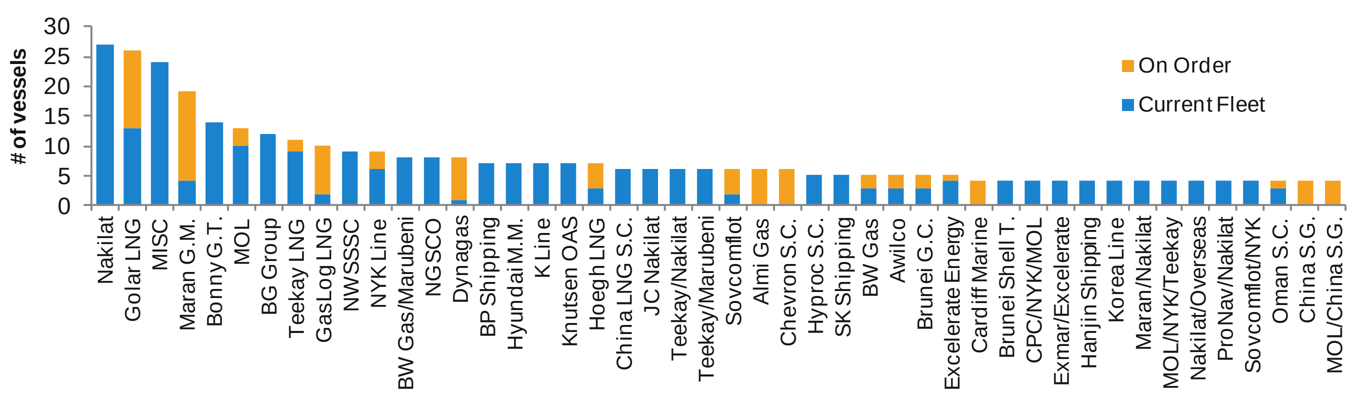


Figure 6.6: New-build Orders (3 or more vessels)

Source: PFC Energy Global LNG Service

2010 due to higher levels of cross-basin arbitrage, encouraged by weakness in North American and European markets, would increase charter distances. The surge in demand for distance-intensive, cross-basin spot LNG associated with the Fukushima crisis in 2011 accelerated the firming of spot-charter rates and would also momentarily lift longer term charter rates above their steady historical averages. Fukushima also led to the current new-build order cycle, which will begin to deliver new tonnage in the second half of 2013.

Al-Khuwair loading at GATE LNG in the Netherlands

Looking Ahead:

Given the large number of unchartered vessels expected to come online in second half of 2013 and first half of 2014, how quickly will rates for short-term charters decline? *Few new LNG projects are expected to come online in 2013 and 2014 – compared to recent years of significant capacity additions – and their incremental shipping demand is expected to be minimal. Unexpected demand-related events will likely provide the greatest support for short-term LNG charter market.*

Will shipping companies with new-build vessels scheduled to come online in 2013 and 2014 delay delivery of their vessels? *Faced with the prospects of a poor shipping market, vessel owners may make arrangements to delay receiving their new vessels in order to defer financial impact.*

How will the greater weakness in short-term charter rates impact decisions to retire older vessels? *The generation of new-build vessels currently under-construction will offer vastly superior operating economics compared to vessels above the age of 25. Given that the strength in the spot charter market has delayed the retirement of many vessels, short-term charter market at rates below $40,000 for older, less efficient vessel types will likely accelerate these decisions.*

Does the favourable shipyard cost trend for new-build LNG vessels continue? *The current boom in new-build vessels orders has benefitted from cyclical downturns in other shipping markets. However, if these markets rebound and shipyards receive more vessel orders for other types, shipyards could withdraw the attractive order terms that they offered for LNG new-builds in 2012.*

Shipping Expedition for the Yamal LNG Project, Russia

7. Special Report on North American LNG Prospects and Challenges

The shale gas revolution in North America has transformed the region from an LNG importer to a potentially massive LNG exporter with proposals for a tremendous amount of new liquefaction capacity associated with existing or "brownfield" regasification terminals and new plants.

A significant rise in unconventional gas production in the United States has seen liquefaction proposals in North America on the order of ~190 MTPA. This is a potentially major change in the role of North America in world LNG activity since the 2005 evaluation of US supply by the National Petroleum Council and statements by former US Federal Reserve Board Chairman Greenspan. However, in putting shale gas resources into play as supplies for LNG export, North American projects face a variety of political and commercial risks, which may have implications for unconventional gas and related LNG developments elsewhere.

7.1. OVERVIEW

As recently as five years ago, North America was preparing to vastly increase LNG imports as the United States and Canada faced declining conventional production. However, the adoption of new drilling techniques and a hospitable regulatory environment paved the way for a massive increase in shale gas production in the continental US. Total gas production, which dipped to less than 52 bcf/d in 2005, increased to over 69 bcf/d in 2012. This growth can be almost entirely attributed to unconventional gas. As a result, North American prices have dropped as market supply surged, with Henry Hub plummeting to $1.94/MMBtu in April 2012. Growth is only expected to continue; the Marcellus shale alone, which contributed only 3.7 bcf/d in 2011 (though that was up from 73 mmcf/d in 2008), is expected to be producing 25 bcf/d by 2020.

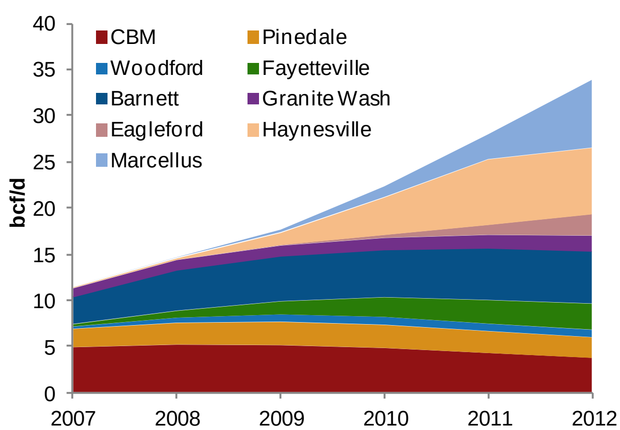


Figure 7.1: Gas Production from Selected Unconventional Plays in the United States

Sources: PFC Energy North America Onshore Service

Meanwhile, LNG demand continues to grow globally, with a number of new countries poised to enter the LNG market, particularly in nearby Latin America. Global LNG prices have climbed in response to rapidly rising demand and higher oil prices. This is especially true in Japan, where the shutdown of nuclear facilities after the March

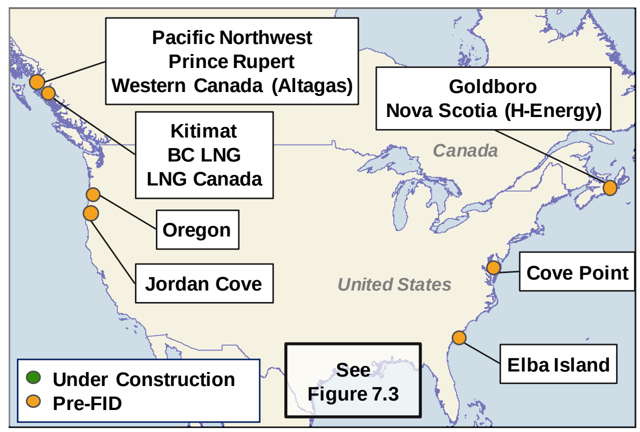


Figure 7.2: Location of Proposed North American Liquefaction Projects, excluding Gulf of Mexico

Sources: PFC Energy Global LNG Service

2011 Fukushima disaster has increased demand for LNG, pushing prices up to ~$15-18/MMBtu. The price differential between oil-linked LNG and Henry Hub is a major factor leading future demand for North American gas as LNG and, thus, for the proposal of so many projects. Major LNG buyers also view North America as a way to diversify their sources of LNG and potential producer risk.

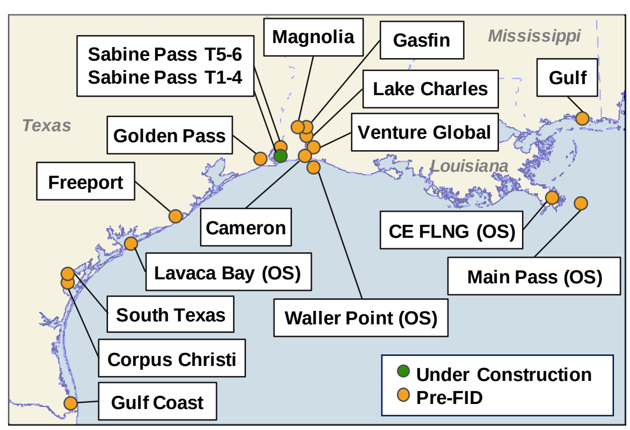


Figure 7.3: Location of Proposed North American Liquefaction Projects, Gulf of Mexico

Sources: PFC Energy Global LNG Service

Project		Capacity	Status	Latest Company Announced Start Date[10]	Operator
United States Lower 48					
Sabine Pass LNG*	T1-2	9	Under Construction	2015	Cheniere Energy
	T3-4	9	Under Construction	2017	
	T5	4.5	Pre-FID	2018	
	T6	4.5	Pre-FID	N/A	
Freeport LNG*	T1-2	8.8	Pre-FID	2017-18	Freeport LNG Liquefaction
	T3	4.4	Pre-FID	2018	
Corpus Christi LNG T1-3		13.5	Pre-FID	2017	Cheniere Energy
Cameron LNG T1-3*		12	Pre-FID	2017-18	Sempra Energy
Cove Point LNG T1-2*		7.8	Pre-FID	2017	Dominion Resources
Jordan Cove LNG		6	Pre-FID	2018	Veresen
Lake Charles LNG T1-3*		15	Pre-FID	2018	Trunkline LNG
Oregon LNG		9	Pre-FID	2017	Oregon LNG
Lavaca Bay Phase 1-2 (OS)		10	Pre-FID	2017	Excelerate Energy
Elba Island LNG T1-2*		2.5	Pre-FID	2015	Southern LNG (Kinder Morgan)
Gulf LNG T1-2*		10	Pre-FID	2018	Gulf LNG (Kinder Morgan)
Magnolia LNG T1-2		4	Pre-FID	N/A	LNG Limited
CE FLNG T1-2 (OS)		8	Pre-FID	N/A	Cambridge Energy Holdings
Golden Pass LNG T1-3*		15.6	Pre-FID	2018	Golden Pass Products (Qatar Petroleum, ExxonMobil)
Gulf Coast LNG T1-4		21	Pre-FID	N/A	Gulf Coast LNG Export
Main Pass Energy Hub LNG (OS)		4	Pre-FID	2017	Freeport-McMoran Energy
Waller Point LNG (OS)		1.25	Pre-FID	2014	Waller Marine, Inc
South Texas LNG T1-2		8	Pre-FID	2018	Pangea LNG
Gasfin LNG		1.5	Pre-FID	N/A	Gasfin Development
Venture Global LNG		5	Pre-FID	N/A	Venture Global Partners
Canada					
LNG Canada T1-2		12	Pre-FID	2019-2020	Royal Dutch Shell
Kitimat LNG	T1	5	Pre-FID	2017	Chevron
	T2	5	Pre-FID	N/A	
Pacific Northwest LNG T1-2		12	Pre-FID	2018	Progress Energy (PETRONAS)
Western Canada LNG		2	Pre-FID	2017	Altagas (Assumed)
Prince Rupert LNG T1-3		N/A	Pre-FID	2019, 2020	BG Group
BC LNG T1-2		1.8	Pre-FID	2015, 2016	BC LNG Export Co-Operative
Goldboro LNG		5	Pre-FID	2018	Pierdae Energy
Nova Scotia LNG		11	Pre-FID	2020	H-Energy

Table 7.1: Proposed Liquefaction Projects in the US Lower 48 and Canada, as of May 2013

** Denotes existing regasification terminal. Projects are listed in the order in which they applied to FERC, followed by the order in which they applied to export to FTA countries at the DOE. Source: PFC Energy Global LNG Service, Company Announcements*

There are also several country-specific issues that have also led to the large number of export proposals. In the United States, extensive existing infrastructure makes the economics of many US projects attractive, and for many companies, liquefaction facilities offer a chance to achieve returns on their existing regasification investments, which in some cases are devoid of activity. After the success of shale production in the United States, several companies have turned their attention to potential shale resources in Western Canada, hoping to replicate the production success in a frontier market less burdened by extensive political debate. Further, projects on the Pacific coast would be advantageously positioned closer to LNG end markets.

7.2. PROPOSED LIQUEFACTION PROJECTS IN THE UNITED STATES AND CANADA

As of May 2013, 20 new liquefaction projects had been proposed in the United States for a total of 46 trains, with an average size of 4.3 mmtpa per train. The majority of these are located along the Gulf Coast, with five projects

[10] *Many of these announced start dates are likely to be delayed.*

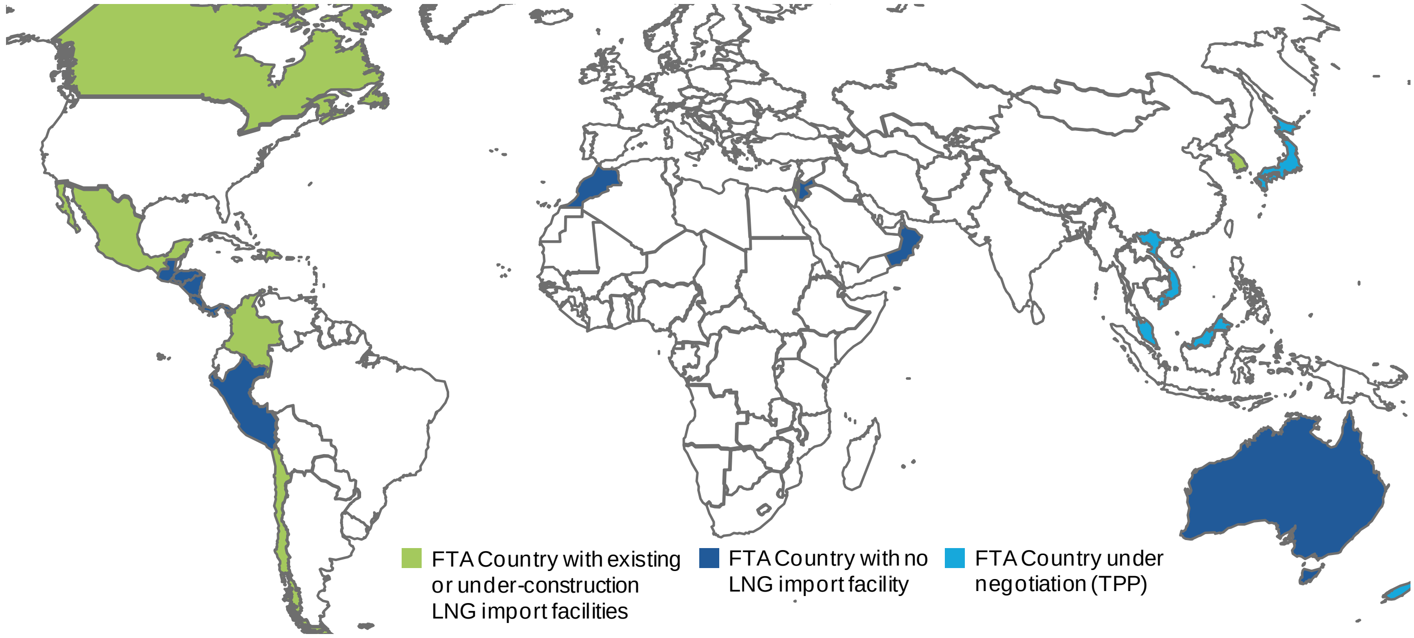


Figure 7.4: Countries with which the US Holds a Free Trade Agreement

Note: Israel and Singapore are FTA countries with regasification capacity; Bahrain is an FTA country with no regasification capacity.

Source: PFC Energy Global LNG Service

in Texas and six in Louisiana, and one at an existing import facility in Mississippi. Two projects have been proposed on the Atlantic Coast, at existing regasification terminals in Maryland and Georgia, while two have been proposed on the Pacific Coast at greenfield sites in Oregon. Finally, four floating projects have been proposed, all of which would be located in the Gulf of Mexico.

In Canada, six LNG export projects have been formally proposed, while two more projects will likely be proposed given recent upstream acquisitions and joint ventures by major liquefaction players and/or LNG buyers. Of the projects, three are located near the city of Kitimat on the coast of British Columbia (including one floating proposal), while two have been proposed ~50 miles northwest at Prince Rupert.

7.3. POLITICAL RISKS FACING PROPOSED NORTH AMERICAN LIQUEFACTION PROJECTS

Projects in Canada and the United States face a varied set of political risks depending on the different political processes in the two countries. Politics thus far have so far been a bigger obstacle to proposals in the United States than in Canada.

7.3.1. US POLITICAL RISKS: EXPORT LICENSES. Out of all 20 projects proposed in the US Lower 48, only the first two phases of Sabine Pass LNG have gained full regulatory approval as of May 2013. US projects must obtain two major sets of approvals to move forward: approval to export LNG from the Department of Energy (DOE) and approval to construct liquefaction facilities from the Federal Energy Regulatory Commission (FERC). The DOE regulates LNG as a commodity in international trade, while FERC regulates the design, construction, and operation of a facility and its impact on the surrounding environment. Other state and local approvals are required, but most of these are addressed during the FERC approval process. Out of 20 new liquefaction projects, 19 have received at least partial approval to export LNG to countries with which the US holds a free trade agreement (FTA) at the DOE, while 16 of those have applied to export to non-FTA countries. Of these, only Sabine Pass T1-4 and Freeport LNG T1-2 have received approval.

20 Total; 7 Importers

Number of countries (total and LNG importers) that hold free trade agreements with the US as of May 2013

Applications to export to FTA countries must be approved without modification or delay under the US Natural Gas Act and, as such, cannot be prohibited by DOE. In contrast, while exports to non-FTA countries are presumed to be in the "public interest" under the Natural Gas Act, the DOE must officially make that determination, which can be later modified, suspended, or rescinded after an administrative proceeding. In non-FTA cases, the presumption under the law is that trade is in the public interest unless evidence proves to the contrary. The treatment of projects potentially serving non-FTA countries has been the major focus of the DOE as a limited upside to LNG demand exists in FTA countries. Although Japan and other Asian countries are under negotiations to become FTA countries under the Trans-Pacific Partnership (TPP) agreement, these negotiations will be lengthy and non-FTA approvals are likely to come first.

Due to the number of proposed projects, significant debate has arisen concerning the approval process, and the DOE put all non-FTA approvals on hold after Sabine Pass while it reviews the process. Continuing and potentially expanding controversies exist over the Natural Gas Act terminology "public interest", which while vaguely defined; is understood to include multiple factors beyond simply the effect on domestic prices will be considered. Political support for LNG exports has gained ground among a wide range of players (including members of Congress, industrial groups, and state and local governments), especially following the release of the DOE-commissioned NERA (founded as National Economic Research Associates) consulting study in December 2012 that had a mostly positive view of the economic effects of LNG exports.

The concern about increased prices is the primary point of several industrial groups (led by Dow Chemical), who remain vocally opposed to unlimited exports, indicating that they would hurt US gas consumers and manufacturers and that a greater economic benefit would be derived by keeping domestic gas within the country. Opposition to the continued use of hydraulic fracturing of shale gas formations ("fracking") remains a factor, represented most strongly by environmental groups like the Sierra Club, particularly in the Northeast and West Coasts. However, very few groups have come out in favor of completely preventing exports, with most calling for delayed approvals to allow for extended research on the environmental effects of fracking or price effects of exports.

19 FTA; 2 Non-FTA

Number of new US liquefaction projects that had been approved for exports to FTA and non-FTA countries as of May 2013

Finally, projects in the US run the risk of an export license revocation if the DOE determines in the future that LNG exports are no longer in the public interest. Due to the uncertainty surrounding what qualifies something as "not in the public interest," the likelihood of an export license revocation is low as it will be difficult to bring evidence supporting such an undefined term. Yet revocation certainly remains a project risk, and the chance could increase if events occurred to turn majority public opinion strongly against gas exports.

7.3.2. US POLITICAL RISKS: ENVIRONMENTAL APPROVAL. Although much attention has been drawn to DOE approval given the current political debate, a project's ability to receive FERC approval is highly critical to its progress, and will likely have a bigger impact on the final slate of projects that are commissioned. Five projects have submitted full applications to the Commission, while another eight have begun the pre-filing process (as has the expansion at Sabine Pass). The FERC process is much longer and more expensive to complete than the DOE process, and no project expects to receive full approval in 2013.

The risk of restrictions on shale gas development imposes indirect but important risks for LNG export projects since overall supply relative to exploitable gas resources may be constrained. In the US, current restrictions at the state level may become important if they are more broadly applied. So far, only Vermont has placed a full ban on fracking at the state level, while others (including Maryland and New York) have placed moratoriums on fracking pending further study of the technique. Other states, such as Wyoming and Ohio have increased drilling reporting standards and other regulation. Jurisdictional restrictions on shale development elsewhere may be likewise important, either by directly constraining LNG feedstock or by limiting domestic gas supplies to the point whereby LNG feedstock is substituted for other parts of the gas transportation chain. Similar issues may emerge in other regions where shale gas development has been discussed, such as Australia or Europe.

The political risk of an individual project increases relative to their position in the queue of export applications at the DOE and FERC. Projects that are able to move most quickly through the review process (especially at FERC) will be able to secure financing and start construction before projects that have faced delays (like projects proposed in Oregon) or those that have filed much later. As each additional project gains financing and begins construction, it becomes less and less likely that another project will be able to do so as the fear of overbuilding becomes more tangible.

7.3.3 CANADA POLITICAL RISKS: EXPORT LICENSES. Liquefaction projects in Western Canada face a smaller range of political risks than those in the Lower 48, as Canada is much more accustomed to energy exports on a large scale (both oil and gas). The government has approved export licenses for those projects that have applied fairly quickly, stating that the major determinant for approval is whether or not a project will cut into domestic gas requirements. Given the large potential of shale gas resources, this is fairly unlikely. Although projects that have not yet received export licenses still face the risk of delay or a potential limit being placed on the number of licenses granted, these risks are quite small.

3 (to all countries)

Number of new Canadian liquefaction projects that had received export licenses as of May 2013

7.3.4 CANADA POLITICAL RISKS: ENVIRONMENTAL APPROVAL. Another issue that could create regulatory risk is environmental opposition to the construction of either the liquefaction facilities or the large pipelines most projects have proposed. There has been significant local backlash to Enbridge's proposed oil pipeline, which would connect Alberta's oil sands to an export terminal at Kitimat, traversing a similar route as many of the proposed gas pipelines towards the coast. However, local groups (including First Nations) have so far put up little opposition to gas facilities, partly due to the differing scale of negative effects of an oil spill versus a gas leak.

The emergence of new importing countries later in the decade has also led to a diversification of market shares, with additions from South America, South & Southeast Asia, and the Middle East. While LNG capacity is expected to stagnate along with demand in traditional North American and European markets, East Asia will continue to experience growth, with planned capacity additions in Japan, Korea, and especially China. Emerging markets are also expected to continue to grow, with a major expansion of regasification capacity expected from South and Southeast Asia, and to a lesser extent South America and the Middle East.

7.4 COMMERCIAL RISKS FACING PROPOSED NORTH AMERICAN LIQUEFACTION PROJECTS

One of the major factors leading to the proposal of so many North American projects is the large price differential between Henry Hub and oil-linked LNG prices. This has opposite effects on the commercial risks for projects in the US Lower 48 and those in Canada.

49.7 MTPA

Contracted LNG (including SPAs, HOAs, and Equity volumes) from the US Lower 48 as of May 2013

7.4.1 US COMMERCIAL RISKS: PROJECT COST (CAPEX). Given this differential and the perceived potential for major arbitrage, the commercial justification for many of the early US Gulf and East Coast projects is strong, though not without risks. Several large LNG traders are eager to sign up for offtake from US projects, both to diversify their sources of LNG and to take advantage of low US gas prices. Further, the costs of building liquefaction facilities are lower due to the extensive infrastructure at existing regasification terminals, including storage and berthing facilities.

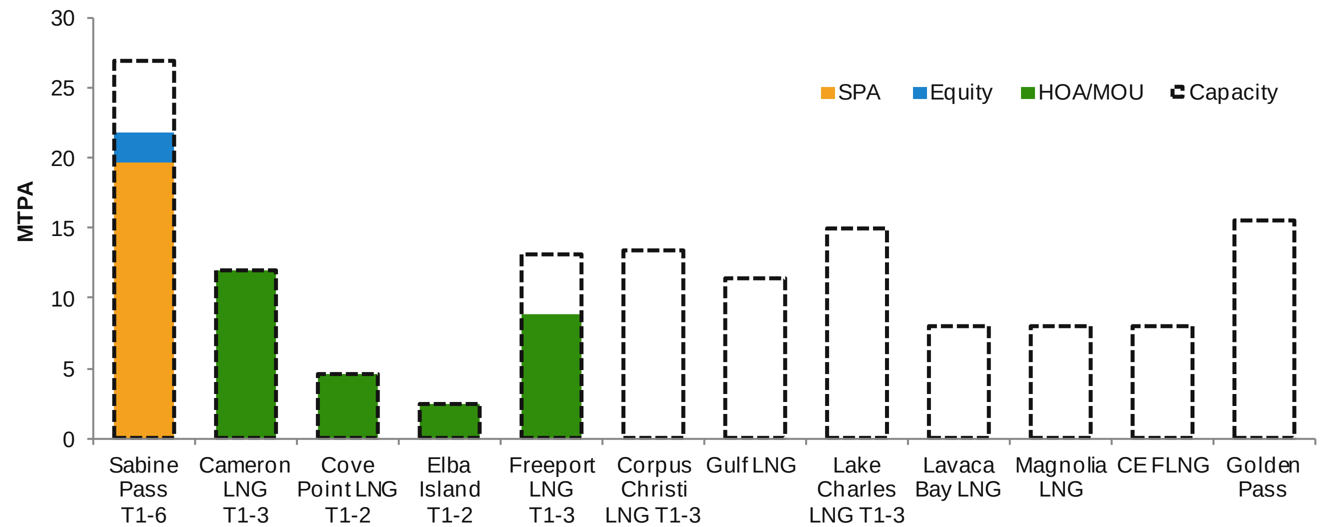


Figure 7.5: Contracting Status of US Lower 48 Liquefaction Projects, as of May 2013[11]

Source: PFC Energy Global LNG Service, Company Announcements

However, the small stature of most of the companies that have proposed the projects may be a barrier. Many companies were hesitant to take LNG from Sabine Pass due to the uncertainty surrounding the creditability of Cheniere, a small company with very little large-scale project experience. This risk was downsized when BG and others signed SPAs, showing confidence in the ability of a small-scale company to move forward, and four other projects have since signed offtake or capacity contracts, for a total of Nonetheless, it remains a commercial risk for other projects, particularly those proposing greenfield facilities who have not demonstrated their ability to bring LNG import projects online.

7.4.2 US COMMERCIAL RISKS: HENRY HUB. There is also an inherent commercial risk tied to the volatility of Henry Hub. When prices are as low as \$3-4/MMBtu, LNG exports from the US are in high demand and competitive on a global scale. However, US gas prices are volatile, with prices as high as \$12/MMBtu as recently as 2008.

Looking retrospectively, if a contract similar to those signed at Sabine Pass had been in place over the past five years (wherein buyers pay the liquefaction owner a set premium of ~15% to Henry Hub for gas procurement in addition to a ~\$3.00/MMBtu liquefaction charge) US-based LNG would only have been cheaper than oil-linked LNG delivered into Japan starting in 2010. Should Henry Hub rise above \$5-6/MMBtu or oil prices fall in the near term, projects that have yet to sign contracts may be delayed as

[11] *Only projects that have begun the FERC process are shown.*

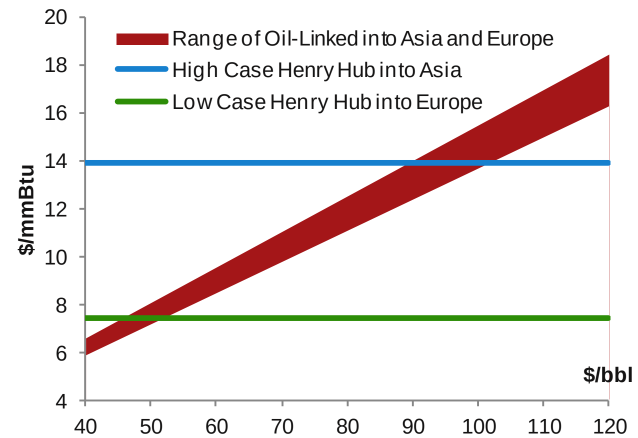


Figure 7.6: Comparison of Henry Hub vs. Oil-Linked LNG Prices

Note: High case Henry Hub into Asia assumes shipping through the Suez Canal; prices would drop if routed through the Panama Canal. Sources: PFC Energy Global LNG Service

the appetite for US-based LNG diminishes.

Further, several projects have been proposed in states fairly distant from Henry Hub, such as Oregon and Maryland. Although these locations are not as divorced from the US pipeline grid as projects in Western Canada, the variations in local infrastructure and distance from producing regions may present a risk to projects. Buyers expect Henry Hub pricing from US projects, and sellers may not always be able to reliably procure gas at the Hub price, particularly in times of peak gas demand, when prices in different regions of the US can vary significantly.

7.4.3 CANADA COMMERCIAL RISKS: PROJECT COST (CAPEX). The commercial position of liquefaction proposals in Western Canada is weakened by the need for greenfield facilities, as well as the early stage of development of the shale gas resource play in Western Canada. Based on announced costs, projects in Western Canada face inexpensive liquefaction costs (~$1,000 /ton) relative to greenfield projects in Australia. However, a major factor affecting Western Canadian projects is the need for a long, expensive pipeline to bring gas from eastern British Columbia to the Coast. Currently, pipeline infrastructure in British Columbia is limited, with one major north-south trunkline and a smaller pipeline running west to the coast. As of may 2013, four projects have proposed building ~500 mile pipelines with costs of between $1,000/mmcf/d - $3,000/mmcf/d, which will significantly increase total project costs.

7.4.4 CANADA COMMERCIAL RISKS: HENRY HUB. These factors are exacerbated by the tension between Asian buyers' insistence on Henry Hub pricing and the sellers' preference for oil-linked prices – a difference that has so far been hard to reconcile. Project costs in Canada far exceed counterpart projects in the United States where the natural gas market is much more liquid. Moreover, the distance between the proposed export facilities and the North American gas pipeline grid is large, and connections are small in both capacity and number. Exporting Henry Hub-linked LNG is risky because it forces sellers to produce no matter what happens to Henry Hub, at a production cost largely divorced from the Hub. This is a problem because Western Canada shale gas will likely be more expensive than the marginal acreage that sets Henry Hub prices. Despite numerous marketing leads for Western Canada's slate of projects, there are currently no finalized agreements with Asia Pacific buyers.

A few projects have attempted to circumvent this issue by creating an integrated project, where likely offtakers have stakes in the upstream. This is the case with LNG Canada and Pacific Northwest LNG; both projects include Asian players in their upstream and liquefaction ownership structures that would likely take LNG back to their home markets, though internal transfer pricing would need to be negotiated between the partners.

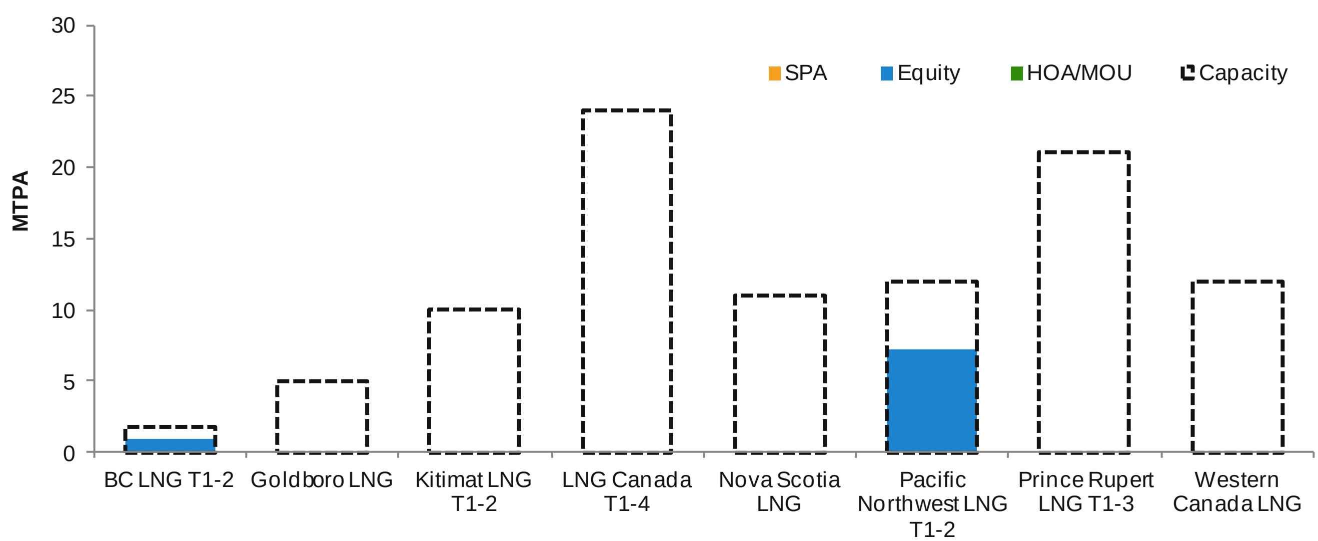


Figure 7.7: Contracting Status of Canadian Liquefaction Projects, as of May 2013

Source: PFC Energy Global LNG Service, Company Announcements

8. Special Report on LNG as Fuel for Transportation

In most countries, LNG is major feedstock for power and industrial sector, but its use in transport is marginal. Nevertheless, there are several factors that indicate that the transport fuel application could revolutionize LNG demand.

Within the transportation sector, LNG has the potential to penetrate the market for shipping fuels and heavy trucking – though the displacement potential may be greater in shipping. A key constraint on the large-scale build up of either LNG or compressed natural gas (CNG, another natural gas alternative) in transportation will be the requisite re-fuelling and distribution infrastructure needed to sustain a large industry.

8.1. DRIVERS FOR LNG AS TRANSPORT FUEL

In recent years, LNG has begun to penetrate the fuels market for both marine (bunker) and road transportation. Compared to conventional fuels used in the transport sector, LNG requires more volumetric space to generate the same energy but it requires approximately 3 times less volume than compressed natural gas (at 200 bar). As a consequence LNG and CNG have different development opportunities. Despite the need for more tank space than other transportation fuels, gas alternatives provide a cheaper and more environmentally-friendly option.

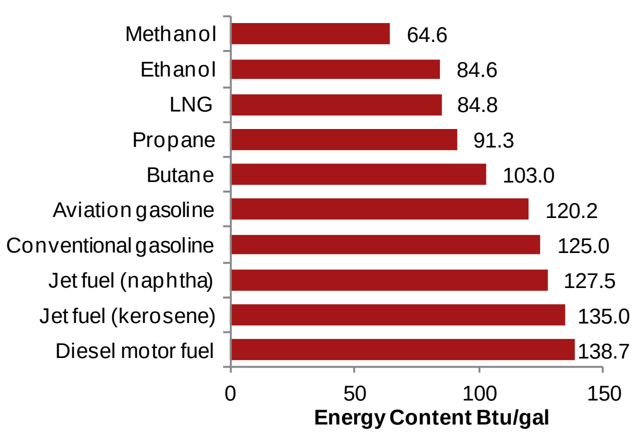


Figure 8.1: Energy Content of Various Transportation Fuels

Sources: Transportation Energy Data Book: Edition 31, Oak Ridge National Laboratory, US Department of Energy

While there are arguments for the growth of LNG in both marine and land based transport, the bunker fuel market is likely to offer more displacement potential in short and medium-term given the stringent environmental regulations that the industry is now facing and due to its importance in global trade.

Macroeconomics and Trade. The marine fuel market is largely driven by macro factors. As global GDP grows, the demand for global trade expands and self-reinforcing dynamic further stimulates GDP. When trade grows, so does the need for transport.

90% of Global Trade Delivered by Ship

Approximately, 90% of global trade is delivered via shipping. And to fuel the global shipping fleet, marine diesel and fuel oil are heavily used.

Global merchandise exports have nearly tripled in value between 2001 and 2011. This is mainly a result in volumetric increases in trade. However, the various routes and distances between suppliers and consumers have grown as well. Based on data from the United Nations Conference on Trade and Development (UNCTAD), seaborne trade has increased from ~29 billion ton-miles (a unit representing both volume and distance) in 2001 to ~43 billion ton-miles in 2011, or a 47% rise. And as a result, there has been a commensurate rise in marine fuel consumption (33% between 2000 and 2010, according to the IEA).

If trade continues to grow on trend (in step with GDP growth) and the structural relationships between the global trade, demand for transport, and fuel used in transport persist, the marine fuel market will need to expand significantly.

Trade Fundamentals	1999 #		2011 #	Units
Global Merchandise Exports	5.72		18.21	trillions of USD
Demand for Transport	26,942		42,794	Ton-miles
Fuel Used in Transport	186.87		244.88*	mmtoe
*2010 figure since 2011 data is not		1999 2002 2005 2008 2011		

Figure 8.2: Trade Fundamentals

Sources: PFC Energy Global LNG Service, UNCTAD, IEA

Sulphur Emission Regulations. In 2015, seaborne traffic in North America, the US Caribbean, and European waters – namely the Baltic Sea, North Sea, and English Channel – will be mandated to reduce fuel sulphur content from 1.0% to 0.1%. This regulation for these Special Emission Control Areas (SECAs) has been established by Annex VI of the International Convention for the Prevention of Pollution From Ships, 1973 as modified by the Protocol of 1978 (MARPOL 73/78).

For signatories of Annex VI that are located outside of the

SECAs, the mandated sulphur content limit will be reduced from the current level of 3.5% to 0.5%. If by 2018 an International Maritime Organization commission finds that there is not enough fuel available with the mandated sulphur level, the reduction to 0.5% may be extended to 2025.

Fuel Price Competitiveness. Another argument for using LNG as fuel in transportation is the disparity between oil and gas prices and the expectation that oil prices may continue to rise exacerbating the gap. The reality is that the spread between conventional fuels and LNG depends on the region. In Japan for example, the LNG discount compared to marine fuels (HFO with 1% sulphur content as a proxy) has been marginal through Q1 2013. However, compared to non-marine fuel (i.e. gasoline), the gap has been wider averaging $4.50/mmBtu. The incentive to switch from HFO or gasoline to LNG is much more substantial in Spain with a $5-10/mmBtu difference.

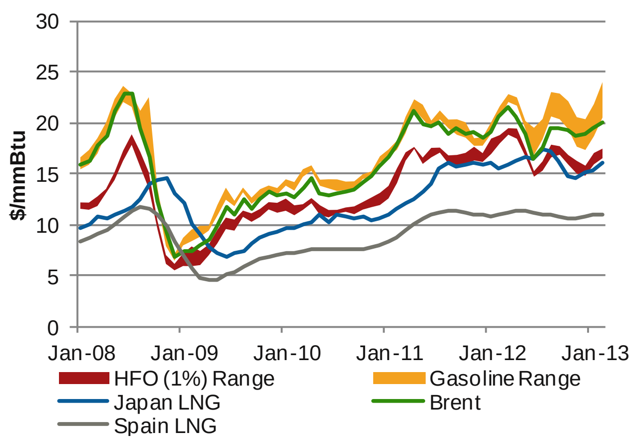


Figure 8.3: Fuel Price Comparison, Jan 2008-Feb 2013

Note: Ranges refer to price benchmark differentials between US Gulf, Latin America, Northwest Europe, and Southeast Asia

Sources: Bloomberg, PFC Energy

Government Support. Some governments have announced support for LNG in the use of transportation. In Europe for example, the European Commission published in January 2013 a draft new Directive aimed at ensuring new infrastructure for alternative clean fuels. The draft directive identifies LNG as a preferred fuel for marine and heavy-duty transport and requires European ports to be able to provide LNG bunker services. Meanwhile, funds have been allocated by several European bodies to projects for building new LNG bunkering infrastructures. Most of them are located along the Northern European coast but Mediterranean countries have recently launched a study with the same objective.

8.2 CONSTRAINTS THE INDUSTRY MUST OVERCOME

Infrastructure Investment. The most challenging hurdle for maximizing LNG use in the transport sector is the substantial investments in associated infrastructure. This would range from LNG storage to refuelling stations both for road transport and bunkering.

Many analysts point to a chicken and egg problem in developing the infrastructure, especially for LNG as a bunker fuel. Ship owners will be hesitant in using LNG as fuel if there is limited infrastructure. But bunker ports will be unwilling to invest in the requisite infrastructure if there is uncertain demand.

Some LNG refuelling stations for road transport already exists and a lot of projects are under development (see Sections 10.3 and 10.4) adding more credibility to this evolving business.

Regulation and Codes. Establishing a strong regulatory framework that is acceptable to the industry could be a time-intensive process. This has been the case in other sectors of the energy industry. The liquefied natural gas industry more specifically has a commendable safety record, and this is largely due to the strict measures associated with each part of the value chain.

LNG Supply Availability. Another major constraint to LNG in transport is the availability of the resource. Through 2015, the LNG market will be supply-constrained until a wave of new Asia Pacific capacity comes online. Although North America and other regions have the potential to deliver significant new volumes to the market, demand is growing globally, especially in Asia. Thus, transportation operators may need to demonstrate a high willingness to pay to firm up supply competing against more traditional buyers.

Thus far, small-scale liquefaction plants (producing less than 0.5 MTPA) are fuelling LNG trucking projects. However, there may need to be a proliferation of these types of projects to boost LNG use in transport to a more substantial level.

8.3 THE EXISTING BUNKER FUEL BUSINESS

Currently there are few vessels that are capable of using LNG as bunker fuel (apart from LNG carriers) and these are mainly in OECD countries. These vessels have been used in a variety of sectors in the shipping industry ranging from tourism to raw materials to offshore oil drilling.

Most of the world's LNG-fuelled ships are located in **Europe** since stringent sulphur content regulations have already been in effect since 2005. A 2012 IGU and UN Economic Commission for Europe study notes that LNG bunkering is especially prevalent in Norway and to a lesser degree in Sweden. Small-scale LNG operations are mostly catering to the industry in Norway – though Snøhvit LNG provides some LNG to Barents Naturgass' bunker terminal in Norway.

Beyond Norway and Sweden, there is interest in developing LNG fuelling capacity for vessels at various ports in the Netherlands, Belgium, United Kingdom, and France. Specifically, the port of Rotterdam in the Netherlands expects to begin LNG bunkering by 2014.

In the **United States and Canada**, Harvey Gulf International Marine (specializing in assisting the offshore oil industry for towing) plans to add new vessels to its fleet that already includes five LNG-fuelled vessels. Similarly two tourism-related companies British Columbia Ferries (private) and Washington State Ferries (state-owned) are considering converting their fleets to LNG. Interlakes Steamship Company (involved in raw materials transport in the US Great Lakes region) has signed a preliminary LNG supply deal with Shell which could accelerate the conversion of several HFO-powered vessels to run on LNG.

Since there are currently no SECAs in **Asia**, there may be less impetus to use LNG compared to Europe and North America. Singapore is one of the more prominent ports in Asia that plans to introduce LNG bunkering. The Maritime and Port Authority of Singapore plans to issue regulations for LNG bunkering by 2014-2015, but acknowledges the likelihood that the adoption of this marine fuel in Singapore may take many more years to come to fruition.

8.4 THE EXISTING TRUCK FUEL BUSINESS

In road transportation, the potential market for natural gas use in vehicles is segmented by the type of vehicle. Compressed natural gas (CNG) is more adapted to light duty vehicles. LNG has proved more viable in heavy duty vehicles, specifically the trucking sector. In many large consumer nations, regulations are currently being implemented and infrastructure is being set up to meet the expected rise in LNG use in trucking.

In **China**, vehicle emissions have been a major driver for improving standards. Currently, the maximum sulphur content is 150 parts per million (ppm). In February 2013, the Standardization Administration of China mandated that the limit be reduced to 50 ppm by 2014 (or the China IV standard), which is in line with European standards. China V which is planned to take effect by 2017 would see this reduced further to just 10 ppm. As a result of these regulatory measures, gas use is expected to increase dramatically. Currently, trucks are the major users of LNG in China – there were approximately 50,000 LNG-fueled trucks in 2012. Given the more restrictive sulphur regulations, there is significant growth potential in the heavy duty vehicles segment.

50,000 LNG-fueled trucks in China in 2012

The **United States** is one of the leaders in terms of LNG use in trucks. As of May 2013, there are 73 LNG re-fuelling stations in operation – 32 of which are open for public use. The major operators include Clean Energy (which includes T. Boone Pickens and Chesapeake Energy as shareholders), Blu LNG (a JV between US-based CH4 and China's ENN Group), and Waste Management (a private environmental solutions provider). The majority of these stations are located on US West Coast.

73 LNG re-fueling stations in US as of May 2013

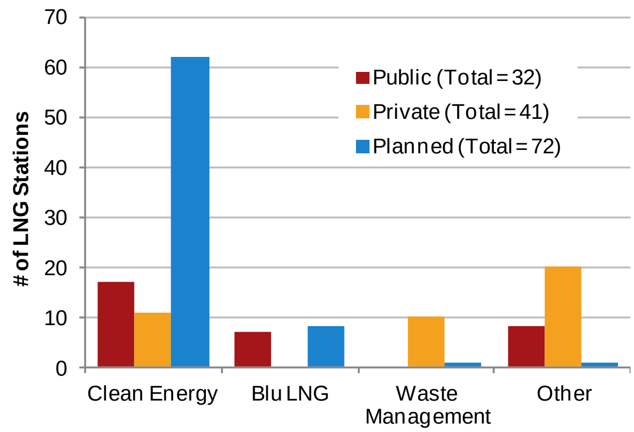


Figure 8.4: LNG Re-fuelling Stations in the US by Owner, as of May 2013

Sources: US Department of Energy Alternative Fuel Data Center, PFC Energy

The US Energy Information Administration (EIA) forecasts a substantial increase in gas use in the transportation sector beginning post 2025. The overwhelming majority of the growth is expected to come from heavy duty vehicles – which can run on both CNG and LNG. In recent years, there has been more commercial momentum supporting LNG for trucking.

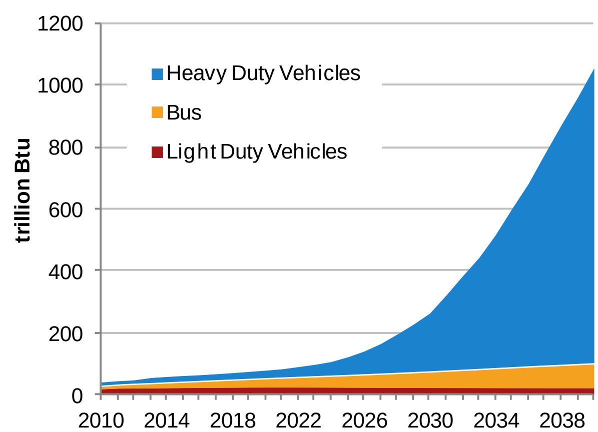


Figure 9.5: Gas Use in the US Transportation Sector

Sources: US Department of Energy Annual Energy Outlook, PFC Energy

As of early 2012, **European countries** that had LNG re-fuelling stations included Portugal, Spain, Italy, Sweden and the Netherlands. These stations are currently geared towards isolated markets. However, the Natural Gas Vehicle Association of Europe and the European Union are jointly sponsoring the LNG Blue Corridors Projects which seeks to set up considerable infrastructure across four major European trucking routes. This includes:

- Portugal-Spain-France-Netherlands-UK-Ireland;
- Portugal-Spain-France-Germany-Denmark-Sweden;
- Mediterranean Arch-Italy-Croatia; and
- Ireland-UK-Belgium-Germany-Austria.

LNG/GNV dual station opened in 2012, Mirandela, Portugal

9. The LNG Industry in Years Ahead

Will LNG supply grow in 2013? For the first time in three decades, LNG supply fell in 2012. In part, this was due to only one new project coming online (Pluto); in part it was due to one-off accidents (a summer fire at MLNG); but in part it reflected structural weakness in either natural gas supply to the plants (Algeria, Egypt, Indonesia) or security (Yemen and Nigeria) as well as non expected maintenance at Norway LNG plant. As demand continues to hold strong, particularly in Asia, the ability of certain producers to grow exports will determine just how tight the market will remain, especially since the only net supply growth in 2013 is expected to come from Angola LNG and probably new trains in Algeria. These various "upstream" uncertainties are difficult to predict and the industry may witness increasing spot and short-term transactions to compensate for the lack of visibility.

Will LNG demand from emerging markets continue to grow? Combined, the imports of Argentina, Chile, Brazil, Kuwait, the UAE, Thailand and Indonesia (from domestic sources) totalled 14.5 MTPA, approximately the amount imported by China in 2012. At the same time, Israel, Malaysia and Singapore began importing in 2013, while other emerging markets (Brazil and Chile) will see expanded regasification capacity. Whether the growth continues in 2013 will depend on a variety of factors, most importantly country-specific energy balances (not just LNG vs. pipeline gas, but gas vs. coal vs. renewables, etc.). New markets are also competing against existing importers (mainly in Asia) that are increasingly turning to flexible LNG. New markets will need to assess the risks of launching terminals without firm commitments for long-term supply. Though this is a non-traditional strategy, developing such projects may meet these countries' short-term or seasonal energy requirements.

Will Asian buyers get new contract terms? In 2012, Asian buyers started to talk openly and repeatedly about shifting from the traditional, fixed-destination, long-term, oil-linked LNG contract. BP and Kansai Electric signed one deal linked to Henry Hub, while Japanese utilities intensified their interest in US LNG (and the Henry-Hub based pricing this entails). But the cracks in the oil-linked system in Asia are few so far. To accelerate a breakthrough, Asian buyers would need to find more traditional sellers willing to sell them LNG at non oil-indexed pricing.

But for higher-cost future suppliers (Australia, Western Canada, and potentially East Africa), even a partial indexation to Hub-based pricing may be difficult to financially justify as they are closely tied to the oil price and because liquefaction and upstream project costs are high. Since the visibility of energy markets is so short, locking in long-term contracts between sellers and buyers has been and will continue to be challenging when negotiating contracts for new projects. For shorter-term deals, though, creativity between parties may help to conclude new supply deals.

Will Henry Hub start rising? Henry Hub closed 2012 without a single month averaging more than $3.5/mmBtu. This price weakness is leading to substantial demand growth in the power sector, is accelerating coal exports, chiefly to Europe, is deepening the shift to liquids-rich plays, and is making foreign companies look at US LNG exports as an attractive proposition. A higher price at Henry Hub and a resulting narrower spread between other price benchmarks (NBP, JCC, WTI, and Brent) could easily temper many of these dynamics.

Will another North American LNG project be sanctioned? PETRONAS LNG T9 and Sabine Pass T3-4 have already taken FID in 2013, but what next? In the United States, the next slate of projects awaits approvals from Federal Energy Regulatory Commission (FERC) and the Department of Energy (DOE). Although the DOE has given the green light to another project (Freeport LNG T1-2), environmental review schedules released by FERC in April and May 2013 show that even the most advanced projects can't expect to receive full federal approval within the year. Even after receiving approval, projects will still have to finalize SPAs and financing agreements, pushing the date for any US sanction into mid-2014 at the earliest. So far, the constituencies favouring LNG exports have been vocal and well organized; but opposition is growing from a group that involves gas users, environmentalists (who are concerned about fracking) and energy "nationalists" who believe that gas should be kept at home. In 2013, we will see how these two coalitions evolve.

Meanwhile, the number of proposed projects in Western Canada continues to grow. Which will gain momentum in 2013? Chevron's entry into Kitimat has re-energized that project, although the project still faces a structural problem (buyers' demand for hub-linked pricing). Will Shell's LNG Canada outpace other projects because it has potential offtakers (KOGAS, PetroChina, and Mitsubishi) in the partnership structure already? Does PETRONAS view Pacific Northwest LNG as a long-term project to meet a future demand problem in Malaysia? Will other acreage holders (BG, ExxonMobil) kick-start their own projects? With all these large players carving out a stake in Western Canada, there may be opportunity to aggregate resources and share infrastructure – but the Queensland industry which had a similar company composition failed to cooperate leaving many operators with high-cost investments.

How will the major emerging gas suppliers move forward? In LNG, there are three main frontier areas besides North America: the Eastern Mediterranean, East Africa (Mozambique and Tanzania), and the Arctic (Yamal and, less so, Alaska). In each of these plays, LNG developments have made active progress either through the addition of partners or through a more precise commercialization method. But all still have to overcome considerable obstacles before sanction.

In pipeline gas, the two main focus areas will continue to be 1) Central Asia and the pace of developing more exports to China, and 2) the Southern Corridor as the decision for Shah Deniz 2 approaches and as Gazprom redoubles its efforts to move ahead with South Stream. At the end of 2013, the industry is likely to have a much better picture of gas flows in SE Europe and from Central Asia.

Will Japan, Korea and Taiwan rethink nuclear power? The electoral win of Shinzo Abe has marked a shift in nuclear power in Japan, bringing to power a government who is keener to see the nuclear energy industry both survive and perhaps grow. Meanwhile, South Korean regulators are tightening oversight over nuclear reactors in response to finds that certificates for many parts were actually fake. And in Taiwan, the Longmen reactor continues to be plagued by long delays. Where exactly will these three countries stand vis-à-vis nuclear power at the end of 2013 and will Japan's record LNG imports in 2012 start to fall?

Will price reform happen in a major way in Asia? China and India, after years of experimenting with gradual price reform, have been tinkering with the possibility of making broader more systematic changes to their gas pricing structures in order to provide greater predictability for companies and consumers. Other countries – such as Malaysia and Bangladesh – are trying to rationalize prices to make imports more viable and profitable. Progress on price reform could have a significant impact on future E&P and imports.

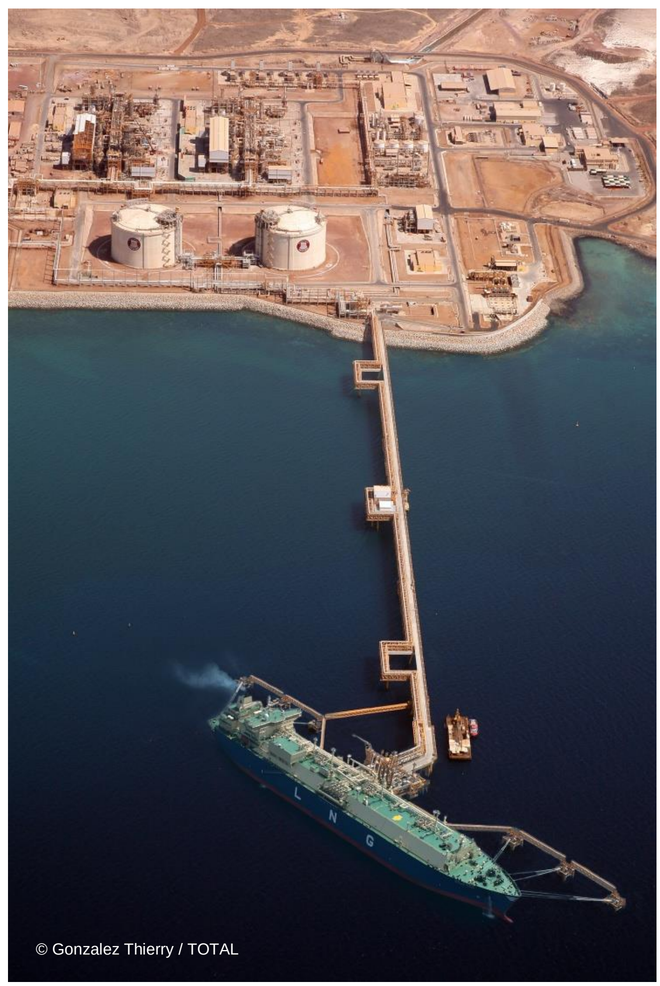
All governments retain energy policy and internal pricing systems as their sovereign tool. Pricing in general will remain dependent upon the government's ability to balance a range of political goals including sovereign "independence", social peace, and employment.

Will Europe's gas market rebound? The growth in coal exports from the United States, the oversupply of carbon credits, a generally anemic economy, and the growth of renewables have all squeezed natural gas demand and the financials of the companies that supply it.

Will 2013 see a continuation of these trends or not? Will European politicians redouble their action on climate change and will they remove incentives for renewables? How exactly will such changes impact gas, and if gas demand does recover, at what price will LNG be available?

Europe is at the center of a pricing battle between the traditional, oil-indexed contract and the new-hub based contract. On the one hand there is weak demand which keeps putting pressure on sellers to make gas more competitive; but on the other, there is a growing supply constraint in the LNG market, which shrinks the alternatives that European buyers can turn to. In part the constraint will impact how pricing negotiations evolve in 2013 and beyond; and in part, the industry will keep searching for a new demand paradigm (for example, in transport) to reenergize a market that has stagnated in recent years.

How will Russia export gas? There is clearly a political and strategic game being played by several actors: Gazprom which wants to preserve its monopoly, Novatek which wants to begin exporting LNG, the Kremlin which wants to increase its Russian gas exports, and other major oil companies who see a possibility to move into territory traditionally held by Gazprom. Meanwhile, European buyers have remained firm in their desire for different pricing structures. Thus, the industry will try to assess in the coming years which internal developments will occur that could change the trajectory of the Russian gas.



First cargo at Yemen LNG, Balhaf, Yemen LNG

APPENDIX I: Table of Operational Liquefaction Plants

Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
US	Kenai LNG*	1969	1.5	ConocoPhillips	ConocoPhillips Optimized Cascade®
Algeria	Skikda - GL1K (T1-4)	1972	1	Sonatrach	Teal (T1-3), PRICO (T4)
Brunei	Brunei LNG T1-5	1972	7.2	Government of Brunei, Shell, Mitsubishi	APC C_3MR
Indonesia	Bontang LNG T1-2	1977	5.4	Pertamina	APC C_3MR
United Arab Emirates	ADGAS LNG T1-2	1977	2.6	ADNOC, Mitsui, BP, TOTAL	APC C_3MR
Algeria	Arzew - GL1Z (T1-6)	1978	6.6	Sonatrach	APC C_3MR
Indonesia	Arun LNG T1	1978	1.65	Pertamina	APC C_3MR
Algeria	Arzew - GL2Z (T1-6)	1981	8.2	Sonatrach	APC C_3MR
Algeria	Skikda - GL2K (T5-6)	1981	2.2	Sonatrach	PRICO
Indonesia	Bontang LNG T3-4	1983	5.4	Pertamina	APC C_3MR
Malaysia	MLNG Satu (T1-3)	1983	8.1	PETRONAS, Mitsubishi, Sarawak State government	APC C_3MR
Indonesia	Arun LNG T6	1986	2.5	Pertamina	APC C_3MR
Australia	North West Shelf T1	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
Australia	North West Shelf T2	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
Indonesia	Bontang LNG T5	1989	2.9	Pertamina	APC C_3MR
Australia	North West Shelf T3	1992	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
Indonesia	Bontang LNG T6	1994	2.9	Pertamina	APC C_3MR
United Arab Emirates	ADGAS LNG T3	1994	3.2	ADNOC, Mitsui, BP, TOTAL	APC C_3MR
Malaysia	MLNG Dua (T1-3)	1995	7.8	PETRONAS, Shell, Mitsubishi, Sarawak State government	APC C_3MR
Qatar	Qatargas I (T1)	1997	3.2	Qatar Petroleum, ExxonMobil, TOTAL,, Marubeni, Mitsui	APC C_3MR
Qatar	Qatargas I (T2)	1997	3.2	Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui	APC C_3MR
Indonesia	Bontang LNG T7	1998	2.7	Pertamina	APC C_3MR
Qatar	Qatargas I (T3)	1998	3.1	Qatar Petroleum, ExxonMobil, TOTAL, Mitsui, Marubeni	APC C_3MR
Indonesia	Bontang LNG T8	1999	3	Pertamina	APC C_3MR
Nigeria	NLNG T1	1999	3.3	NNPC, Shell, TOTAL, Eni	APC C_3MR
Qatar	RasGas I (T1)	1999	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	APC C_3MR
Trinidad	ALNG T1	1999	3.3	BP, BG, Repsol**, CIC, NGC Trinidad	ConocoPhillips Optimized Cascade®
Nigeria	NLNG T2	2000	3.3	NNPC, Shell, TOTAL, Eni	APC C_3MR
Oman	Oman LNG T1	2000	3.55	Petroleum Development Oman (PDO), Shell, TOTAL, Korea LNG, Partex, Mitsubishi, Mitsui, Itochu	APC C_3MR
Oman	Oman LNG T2	2000	3.55	Petroleum Development Oman (PDO), Shell, TOTAL, Korea LNG, Partex, Mitsubishi, Mitsui, Itochu	APC C_3MR
Qatar	RasGas I (T2)	2000	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	APC C_3MR
Nigeria	NLNG T3	2002	3	NNPC, Shell, TOTAL, Eni	APC C_3MR
Trinidad	ALNG T2	2002	3.5	BP, BG, Repsol**	ConocoPhillips Optimized Cascade®
Malaysia	MLNG Tiga (T1-2)	2003	6.8	PETRONAS, Shell, Nippon, Sarawak State government, Mitsubishi	APC C_3MR

Trinidad	ALNG T3	2003	3.5	BP, BG, Shell	ConocoPhillips Optimized Cascade®
Australia	North West Shelf T4	2004	4.4	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
Qatar	RasGas II (T1)	2004	4.7	Qatar Petroleum, ExxonMobil	APC C_3MR/ Split MR™
Egypt	ELNG T1	2005	3.6	BG, PETRONAS, EGAS, EGPC, GDF SUEZ	ConocoPhillips Optimized Cascade®
Egypt	ELNG T2	2005	3.6	BG, PETRONAS, EGAS, EGPC	ConocoPhillips Optimized Cascade®
Egypt	SEGAS T1	2005	5	Gas Natural Fenosa, Eni, EGPC, EGAS	APC C_3MR/ Split MR™
Qatar	RasGas II (T2)	2005	4.7	Qatar Petroleum, ExxonMobil	APC C_3MR/ Split MR™
Australia	Darwin LNG T1	2006	3.6	ConocoPhillips, Santos, INPEX, Eni, TEPCO, Tokyo Gas	ConocoPhillips Optimized Cascade®
Nigeria	NLNG T4	2006	4.1	NNPC, Shell, TOTAL, Eni	APC C_3MR
Nigeria	NLNG T5	2006	4.1	NNPC, Shell, TOTAL, Eni	APC C_3MR
Oman	Qalhat LNG	2006	3.7	Omani Govt, Petroleum Development Oman (PDO), Shell, Mitsubishi, Gas Natural Fenosa, Eni, Itochu, Osaka Gas, TOTAL, Korea LNG, Mitsui, Partex	APC C_3MR
Trinidad	ALNG T4	2006	5.2	BP, BG, Repsol**, NGC Trinidad	ConocoPhillips Optimized Cascade®
Equatorial Guinea	EG LNG T1	2007	3.7	Marathon, Sonagas, Mitsui, Marubeni	ConocoPhillips Optimized Cascade®
Norway	Snøhvit LNG T1	2007	4.2	Statoil, Petoro, TOTAL, GDF SUEZ, RWE	Linde MFC
Qatar	RasGas II (T3)	2007	4.7	Qatar Petroleum, ExxonMobil	APC C_3MR/ Split MR™
Australia	North West Shelf T5	2008	4.4	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
Nigeria	NLNG T6	2008	4.1	NNPC, Shell, TOTAL, Eni	APC C_3MR
Indonesia	Tangguh LNG T1	2009	3.8	BP, CNOOC, Mitsubishi, INPEX, JOGMEC, JX Nippon Oil & Energy, LNG Japan, Talisman Energy, Kanematsu, Mitsui	APC C_3MR/ Split MR™
Indonesia	Tangguh LNG T2	2009	3.8	BP, CNOOC, Mitsubishi, INPEX, JOGMEC, JX Nippon Oil & Energy, LNG Japan, Talisman Energy, Kanematsu, Mitsui	APC C_3MR/ Split MR™
Qatar	Qatargas II (T1)	2009	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
Qatar	Qatargas II (T2)	2009	7.8	Qatar Petroleum, ExxonMobil, TOTAL	APC AP-X
Qatar	RasGas III (T1)	2009	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
Russia	Sakhalin 2 (T1)	2009	4.8	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
Russia	Sakhalin 2 (T2)	2009	4.8	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
Yemen	Yemen LNG T1	2009	3.35	TOTAL, Hunt Oil, Yemen Gas Co., SK Corp, KOGAS, GASSP, Hyundai	APC C_3MR/ Split MR™
Malaysia	MLNG Dua Debottleneck	2010	1.2	PETRONAS, Shell, Mitsubishi, Sarawak State government	APC C_3MR
Norway	Skangass LNG	2010	0.3	Skangass	Linde LIMUM
Peru	Peru LNG	2010	4.45	Hunt Oil, Repsol**, SK Corp, Marubeni	APC C_3MR/ Split MR™
Qatar	Qatargas III	2010	7.8	Qatar Petroleum, ConocoPhillips, Mitsui	APC AP-X
Qatar	RasGas III (T2)	2010	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
Yemen	Yemen LNG T2	2010	3.35	TOTAL, Hunt Oil, Yemen Gas Co., SK Corp, KOGAS, GASSP, Hyundai	APC C_3MR/ Split MR™
Qatar	Qatargas IV	2011	7.8	Qatar Petroleum, Shell	APC AP-X
Australia	Pluto LNG T1	2012	4.3	Woodside, Kansai Electric, Tokyo Gas	Shell propane pre-cooled mixed refrigerant design

Source: PFC Energy Global LNG Service, Company Announcements

** Companies are listed by size of ownership stake, starting with the largest stake*
*** Shell agreed to acquire Repsol's assets in February 2013.*

APPENDIX II: Table of Liquefaction Plants Under Construction

Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*
Algeria	Skikda - GL1K Rebuild**	2013	4.5	Sonatrach
Angola	Angola LNG T1	2013	5.2	Chevron, Sonangol, BP, Eni, TOTAL
Indonesia	Senkang LNG T1	2013	0.5	Energy World Corporation
Indonesia	Senkang LNG T2	2013	0.5	Energy World Corporation
Algeria	Arzew - GL3Z (Gassi Touil)	2014	4.7	Sonatrach
Colombia	Pacific Rubiales	2014	0.5	Exmar
Indonesia	Donggi-Senoro LNG	2014	2	Mitsubishi, Pertamina, KOGAS, Medco
Papua New Guinea	PNG LNG T1	2014	3.5	ExxonMobil, Oil Search, Government of Papua New Guinea, Santos, Nippon Oil, PNG Landowners (MRDC), Marubeni, Petromin PNG
Papua New Guinea	PNG LNG T2	2014	3.5	ExxonMobil, Oil Search, Government of Papua New Guinea, Santos, JX Nippon Oil & Energy, MRDC, Marubeni, Petromin PNG
Malaysia	MLNG Mini-Expansion	2014	0.67	PETRONAS
Australia	Queensland Curtis LNG T1	2014	4.3	BG, CNOOC
Australia	Queensland Curtis LNG T2	2015	4.3	BG, Tokyo Gas
Malaysia	PETRONAS LNG 9	2015	3.6	PETRONAS
Australia	Australia Pacific LNG T1	2015	4.5	ConocoPhillips, Origin Energy, Sinopec
Australia	Australia Pacific LNG T2	2015	4.5	ConocoPhillips, Origin Energy, Sinopec
Australia	Gladstone LNG T1	2015	3.9	Santos, PETRONAS, TOTAL, KOGAS
Malaysia	PETRONAS FLNG	2015	1.2	PETRONAS
US	Sabine Pass T1	2015	4.5	Cheniere
Australia	Gorgon LNG T1	2015	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric
Australia	Gorgon LNG T2	2015	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric
Australia	Gorgon LNG T3	2016	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric
Australia	Gladstone LNG T2	2016	3.9	Santos, PETRONAS, TOTAL, KOGAS
Australia	Wheatstone LNG T1	2016	4.5	Chevron, Apache, Pan Pacific Energy, KUFPEC, Shell, Kyushu Electric
US	Sabine Pass T2	2016	4.5	Cheniere
US	Sabine Pass T3	2016	4.5	Cheniere
US	Sabine Pass T4	2017	4.5	Cheniere
Australia	Wheatstone LNG T2	2017	4.5	Chevron, Apache, Pan Pacific Energy, KUFPEC, Shell, Kyushu Electric
Australia	Ichthys LNG T1	2017	4.2	INPEX, TOTAL, Tokyo Gas, Osaka Gas, Chubu Electric, Toho Gas
Australia	Ichthys LNG T2	2017	4.2	INPEX, TOTAL, Tokyo Gas, Osaka Gas, Chubu Electric, Toho Gas
Australia	Prelude LNG (Floating)	2017	3.6	Shell, INPEX, KOGAS, CPC

Source: PFC Energy Global LNG Service, Company Announcements

** Companies are listed by size of ownership stake, starting with the largest stake*
*** Construction has been completed, but the project has yet to deliver LNG*

APPENDIX III: Table of Recently Commissioned LNG Receiving Terminals

Country	Terminal or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
Belgium	Zeebrugge (Expansion)	2008	3.3	Fluxys	Onshore
China	Fujian LNG	2008	2.6	CNOOC, Fujian Investment & Development Co.	Onshore
China	Mengtougou	2008	0.1	Shanghai Gas Group	Onshore
India	Hazira LNG (Debottleneck)	2008	1.1	Shell, TOTAL	Onshore
Japan	Sodegaura (Expansion)	2008	1.6	TEPCO, Tokyo Gas	Onshore
Mexico	Costa Azul	2008	7.5	Sempra	Onshore
UK	Grain LNG (Phase 2)	2008	6.5	National Grid Transco	Onshore
US	Freeport LNG	2008	11.3	Freeport LNG	Onshore
US	Northeast Gateway	2008	3	Excelerate Energy	Floating
US	Sabine Pass	2008	19.6	Cheniere Energy	Onshore
Brazil	Pecem	2009	1.9	Petrobras	Floating
Canada	Canaport	2009	7.5	Repsol, Irving Oil	Onshore
Chile	Quintero LNG	2009	2.5	BG Group, ENAP,ENAGAS, ENDESA, Metrogas	Onshore
China	Dapeng LNG (Guangdong, Expansion)	2009	3	CNOOC, BP, Local Companies	Onshore
China	Shanghai LNG	2009	3	Shenergy Group, CNOOC	Onshore
India	Dahej LNG (Expansion)	2009	3.5	Petronet LNG	Onshore
Italy	Adriatic LNG/Rovigo	2009	5.8	ExxonMobil, Qatar Petroleum, Edison	Offshore
Kuwait	Mina Al-Ahmadi GasPort Excelerate Energy FSRU Contract	2009	3.8	Kuwait Petroleum Corporation	Floating
Spain	Saggas (Expansion 2)	2009	1.2	RREEF Infrastructure, Eni, Gas Natural Fenosa, Osaka Gas, Oman Oil	Onshore
Taiwan	Taichung LNG	2009	3	CPC	Onshore
UK	Dragon LNG	2009	4.4	BG Group, PETRONAS, 4Gas	Onshore
UK	South Hook (Phase 1)	2009	7.8	Qatar Petroleum, ExxonMobil, TOTAL	Onshore
US	Cameron LNG	2009	11.3	Sempra	Onshore
US	Cove Point (Expansion)	2009	5.5	Dominion Cove Point LNG	Onshore
US	Sabine Pass (Expansion)	2009	10.6	Cheniere Energy	Onshore
Chile	Mejillones LNG (Phase 1)	2010	1.5	GDF SUEZ, Codelco	Onshore
France	FosMax LNG (Fos Cavaou)	2010	6	GDF SUEZ, TOTAL	Onshore
Japan	Sakaide	2010	0.7	Shikoku Electric, Cosmo Gas, Shikoku Gas	Onshore
Spain	Barcelona (Expansion)	2010	4.7	ENAGAS	Onshore
UK	Grain LNG (Phase 3)	2010	5.2	National Grid Transco	Onshore
UK	South Hook (Phase 2)	2010	7.8	Qatar Petroleum, ExxonMobil, TOTAL	Onshore
United Arab Emirates	Dubai (OS)	2010	3	Dubai Supply Authority	Floating
US	Elba Island III (Phase 1)	2010	3.5	Kinder Morgan	Onshore
US	Lake Charles (IEP)	2010	3.9	Southern Union, AIG Highstar	Onshore
US	Neptune LNG	2010	3	GDF SUEZ	Floating
Argentina	Bahia Blanca GasPort (Expansion)	2011	3.8	YPF	Floating
Argentina	Puerto Escobar	2011	3.8	Enarsa, YPF	Floating
China	Dalian	2011	3	PetroChina, Dalian Port, Dalian Construction Investment Corp	Onshore
China	Fujian LNG (Storage Expansion)	2011	N/A	CNOOC, Fujian Investment & Development Co.	Onshore
China	Rudong/Jiangsu LNG	2011	3.5	PetroChina, Pacific Oil, Jiangsu Guoxin	Onshore

Japan	Mizushima LNG (Expansion)	2011	0.9	Chugoku Electric, JX Nippon Oil & Energy	Onshore
Japan	Ohgishima (Expansion)	2011	1.6	Tokyo Gas	Onshore
Japan	Yufutsu	2011	0.04	Japex	Onshore
Netherlands	GATE LNG	2011	8.8	Gasunie, Vopak, Dong, OMV	Onshore
Norway	Fredrikstad	2011	0.04	Skangass LNG	Onshore
Spain	Huelva (Storage Expansion)	2011	0	ENAGAS	Onshore
Spain	Saggas (Expansion)	2011	0.9	RREEF Infrastructure, Eni, Gas Natural Fenosa, Osaka Gas, Oman Oil	Onshore
Sweden	Nynashamn LNG	2011	0.3	AGA Gas AB	Onshore
Thailand	Rayong	2011	5	PTT, EGAT, EGC	Onshore
US	Golden Pass Phase 1	2011	7.5	Qatar Petroleum, ExxonMobil, ConocoPhillips	Onshore
US	Golden Pass Phase 2	2011	8.1	Qatar Petroleum, ExxonMobil, ConocoPhillips	Onshore
US	Gulf LNG	2011	11.3	Kinder Morgan, GE Energy Financial Services, Sonangol	Onshore
Brazil	Guanabara LNG/Rio de Janeiro Excelerate Energy Bridging FSRU	2012	4.7	Petrobras	Onshore
Indonesia	Nusantara	2012	3.8	Pertamina, PGN	Floating
Japan	Ishikari LNG	2012	1.4	Hokkaido Gas	Onshore
Japan	Joetsu	2012	N/A	Chubu Electric	Onshore
Japan	Yoshinoura	2012	0.5	Okinawa Electric	Onshore
Mexico	Manzanillo	2012	3.8	Mitsui, Samsung, KOGAS	Onshore
Portugal	Sines LNG (Expansion Phase 1)	2012	2	REN	Onshore
Puerto Rico	Peñuelas (Expansion)	2012	0.6	Gas Natural Fenosa, International Power, Mitsui, GE Capital	Onshore
China	Ningbo, Zhejiang	2013	3	CNOOC, Ningbo Power Development Co Ltd, Zhejiang Energy Group Co Ltd	Onshore
India	Dabhol LNG	2013	2	GAIL, NTPC, Indian financial institutions, MSEB Holding Co.	Onshore
India	Hazira LNG (Expansion)	2013	1.4	Shell, TOTAL	Onshore
Israel	Hadera Gateway	2013	1.8	Israel Natural Gas Lines	Floating
Singapore	Jurong Island LNG Phase 1	2013	3.5	Singapore Energy Market Authority	Onshore
Malaysia	Lekas LNG	2013	3.8	PETRONAS	Onshore

Source: PFC Energy Global LNG Service, Company Announcements

** Companies are listed by size of ownership stake, starting with the largest stake*

APPENDIX IV: Table of LNG Receiving Terminals Under Construction

Country	Terminal or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Project Partners*	Concept
Brazil	Bahia/TRBA	2013	3.8	Petrobras	Floating
Chile	Mejillones LNG (Phase 2)	2013	1.5	GDF SUEZ, Codelco	Onshore
China	Tangshan (Caofeidian) LNG	2013	3.5	PetroChina	Onshore
China	Tianjin FSRU	2013	2.2	CNOOC	Floating
China	Zhuhai (CNOOC)	2013	3.5	CNOOC, Guangdong Gas, Local Companies	Onshore
India	Kochi LNG	2013	2.5	Petronet LNG	Onshore
Italy	Livorno/LNG Toscana	2013	2.7	E.ON, IREN, OLT Energy, Golar	Floating
Malaysia	Lekas LNG (Malacca)**	2013	3.8	PETRONAS	Onshore
Brazil	Guanabara LNG/Rio de Janeiro Excelerate Energy VT3 FSRU Contract	2014	5.3	Petrobras	Floating
Chile	Colbún	2014	3.8	AES, Colbun	Floating
China	Hainan LNG	2014	2	CNOOC, Hainan Development Holding Co.	Onshore
China	Qingdao	2014	3	Sinopec	Onshore
Colombia	Puerto Bahia LNG	2014	N/A	Exmar	Onshore
India	Dahej LNG (Second Expansion Phase 1)	2014	2.5	Petronet LNG	Onshore
India	Kochi LNG Phase 2	2014	2.5	Petronet LNG	Onshore
Indonesia	Lampung LNG	2014	2	Pertamina, PGN	Floating
Japan	Hibiki LNG	2014	3.5	Saibu Gas, Kyushu Electric	Onshore
Japan	Naoetsu	2014	1.5	INPEX	Onshore
Lithuania	Klaipeda LNG	2014	2.2	Klaipedos Nafta	Floating
Poland	Swinoujscie	2014	3.6	GAZ-SYSTEM SA	Onshore
Singapore	Jurong Island LNG Phase 2	2014	2.5	Singapore Energy Market Authority	Onshore
Spain	Bilbao (Expansion)	2014	2.6	ENAGAS, EVE, RREEF Infrastructure	Onshore
Chile	GasAtacama	2015	1.1	GasAtacama	Floating
China	Beihai, Guangxi LNG	2015	3	Sinopec	Onshore
China	Shenzhen (Diefu)	2015	4	CNOOC, Shenzhen Energy Group	Onshore
France	Dunkirk LNG	2015	9.5	EDF, Fluxys, TOTAL	Onshore
Japan	Hachinohe LNG	2015	1.5	JX Nippon Oil & Energy	Onshore
Japan	Kushiro LNG	2015	0.5	JX Nippon Oil & Energy	Onshore
Korea	Samcheok	2015	6.8	KOGAS	Onshore
Japan	Hitachi	2016	N/A	Tokyo Gas	Onshore

Source: PFC Energy Global LNG Service, Company Announcements

** Companies are listed by size of ownership stake, starting with the largest stake*

***Malaysia's Lekas LNG terminal is commissioning.*

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10. Waterborne LNG Reports

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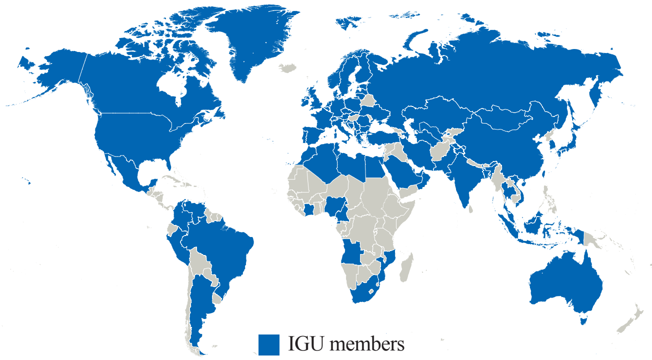

INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ

International Gas Union
Office of the Secretary General
c/o Statoil ASA

P.O. Box 3
NO – 1330 Fornebu
Norway
Telephone: +47 51 99 00 00
Fax +47 67 80 56 01
Email: secrigu@statoil.com
Website: www.igu.org

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