International Gas Union

News, views and knowledge on gas – worldwide

World LNG Report - 2015 Edition

World Gas Conference Edition

Sponsored by:

TOTAL
COMMITTED TO BETTER ENERGY

IGU
INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ

#MakeThingsBetter
total.com
Oil, natural gas and solar energy – 100,000 women and men
COMMITTED TO BETTER ENERGY
TOTAL
COMMITTED TO BETTER ENERGY

Table of Contents

1. Message from the President of the International Gas Union

Dear colleagues,

A number of events had an impact on the energy industry in 2014 and 2015.

Firstly, the economic crisis, which created a slowdown in demand. It will probably affect the oil industry harder than the gas industry, except in Europe where coal consumption is increasingly being used as a substitute for gas to fire electric power stations.

Secondly, the geopolitical crisis that arose during the summer of 2014 between Russia and Ukraine revived Western Europe's fears over the risks of gas shortages and security of supply. It led the industry to consider the catastrophic effects a major break in supply would have.

And thirdly, the spectacular and unexpected tumble in oil prices. The cost of oil was halved in just a few weeks before flattening out at around $60/barrel. This upset all the energy strategies, which were based on high oil prices. Gas also suffered mixed fortunes throughout this difficult and turbulent time.

Asia in general and China in particular continued to negotiate gas supply contracts and North America kept on exploiting its shale gas reserves to satisfy growing domestic demand. Only Europe saw demand for gas fall sharply due to the combined effects of the economic crisis and a greater use of coal by electric power stations.

All eyes have turned to LNG as it has emerged as a useful back up resource for diversifying and securing energy supplies. Investment decisions on LNG projects, both firm and pending, were unaffected by the unstable market and went ahead as planned. However most of the projects under assessment have been put on hold until a clearer picture emerges of evolving energy costs and demand, so that the costs of certain projects can be reviewed downwards.

The International Energy Agency's latest forecasts in November 2014 confirmed previous forecasts predicting a sustained growth in gas consumption over the next few years (+1.6% a year), to position gas as the second largest source of energy, behind oil but ahead of coal, by 2040 with a 24% share of the energy mix (compared to 21% in 2012). By then, LNG will have consolidated its position on international gas markets and the commissioning of new gas liquefaction plants in Australia, the US, Russia, Africa and the Middle East will provide greater flexibility and help to secure energy supplies on these markets.

Gas can continue to look forward to a bright future thanks to the development of global conventional and unconventional reserves and the major role played by LNG.

Yours sincerely,

Jérôme Ferrier
President of the International Gas Union

2. State of the LNG Industry

241 MTPA
Global trade in 2014

Global Trade: LNG trade reached 241.1 MT in 2014, a 4.3 MT increase over 2013 levels. This marked the second highest year for LNG trade on record, just short of the 241.5 MT traded in 2011. Higher supply was underpinned by the start-up of PNG LNG in Papua New Guinea (PNG), as well as improved output from both Pacific and Atlantic Basin projects. These gains were offset by lower than expected output from Angola LNG and feedstock issues in Egypt. The Pacific Basin, led by Japan, remained the largest source of demand, while Qatar maintained its position as the largest LNG supplier.

$15.6/mmBtu
Average LNG import price in Japan, 2014

Global Prices: Pacific Basin LNG import prices remained strong in 2014. Northeast Asian spot and Japanese LNG imports prices both averaged over $15.0/mmBtu. However, these prices came under pressure in late 2014 due to more moderate demand and falling oil prices. These effects persisted in early 2015, leading to a levelling of European and Northeast Asian spot LNG prices. While Henry Hub continued to trade at a discount to European and Pacific Basin markets in 2014, finishing the year at $3.4/mmBtu, the German border-price and NBP fell from $10/mmBtu in early 2014 to near $8/mmBtu at year-end.

64.7 MT
Spot and short-term trade, 2014

Spot, Medium and Long-term LNG Market (as defined in Chapter 12): Long-term contracts continued to drive the LNG market, accounting for 69% of global trade in 2014. A dynamic spot and short-term market covered a further 27% of total trade in 2014. Nearly 75% of these volumes were consumed in the Pacific Basin. While medium-term trade has grown in recent years, it remains a small component of global trade at ~10 MT (4%) in 2014.

301 MTPA
Global liquefaction capacity, end-2014

Liquefaction Plants: Following limited growth since 2011, global nominal liquefaction capacity increased by over 10 MTPA in 2014 with the start of PNG LNG, Arzew GL3Z in Algeria and Queensland Curtis LNG (QCLNG) in Australia. Nearly 130 MTPA of capacity is under construction from projects due on-stream this decade. Australia is likely to become the world's largest exporter, adding 58 MTPA by 2018. US projects are also set to add 44 MTPA before 2020.

750+ MTPA
Proposed liquefaction capacity in new LNG frontiers

New Liquefaction Frontiers: Several frontier LNG regions have emerged in recent years. Among these are the US Gulf Coast and Canada (due to shale gas production), East Africa (due to prolific deepwater basins), floating LNG globally (because of stranded gas), Asia Pacific brownfield projects, Russian projects and East Mediterranean projects. 750+ MTPA of new capacity has been proposed in these regions, ~80 % in North America.

724 MTPA
Global regasification capacity, end-2014

Regasification Terminals: Global nominal regasification capacity reached 724 MTPA in 2014 (up from 693 MTPA in 2013). Lithuania became the 30th country to enter the LNG market in 2014. Other capacity additions came from markets already importing LNG. While Japan, South Korea and China completed large-scale import facilities, new terminals were also brought online in Brazil and Indonesia. Chile, Kuwait, Singapore and Brazil finalised terminal expansions.

54 MTPA
FSRU capacity, end-2014

Floating Regasification: Global floating regasification capacity has nearly doubled since 2010, reaching 54 MTPA in 2014 with 16 active terminals in 11 countries. While three new terminals came online in Brazil, Indonesia and Lithuania in 2014, two terminals in Kuwait and Brazil completed expansions. Five additional floating projects with a combined capacity of 16.2 MTPA are under construction, four of which are in new LNG import markets.

373 Carriers
LNG fleet, end-2014

Shipping Fleet: At the end of 2014, the global LNG fleet was composed of 373 carriers with a combined capacity of 55 mmcm. 28 vessels were delivered in 2014 as speculative newbuilds entered the market. With ample tonnage open for charter, short-term charter rates came under pressure throughout the year. This dynamic is expected to persist in 2015 as additional speculative capacity enters the market, outpacing LNG supply growth.

10% of Supply
Share of LNG in global gas supply

LNG Positioning: Natural gas accounts for around 1/4 of global energy demand, of which 10% is supplied in the form of LNG. This compares to just 4% in 1990. LNG supply has grown faster than any other source of gas – at an average 7% per year since 2000 – and is poised to expand its share of the gas market to 2020.

20 MTPA
SSLNG installed capacity, 2014

Small-Scale LNG: Global small-scale LNG (SSLNG) installed capacity stood at 20 MTPA in 2014. The industry is rapidly expanding as countries seek to cut emissions, reduce fuel costs, access isolated customers and reach new markets. The maturation of SSLNG technology has been a key factor in driving the business forward, counteracting diseconomies of scale and reducing initial investment costs. While China is leading SSLNG growth, significant advances have also been made globally.

3. LNG Trade

Global trade volumes strengthened in 2014, rising above 241 MT and marking the 2nd highest year for LNG trade in the industry's history. Higher trade was underpinned by new supply from PNG, which became the world's 19th LNG exporter. This was supported by improved output from Nigeria and Algeria in the Atlantic Basin, though feedstock issues in Egypt and the closure of Angola LNG limited further growth. Lithuania joined the ranks of LNG importers in 2014, bringing the number of countries sourcing LNG from the global market to 29. Regional import patterns held steady, with the Pacific Basin commanding the largest share of demand and continuing to support interregional trade flows as Atlantic Basin demand remained depressed.

The global LNG market is primed for significant change in the years ahead as new supplies from the Pacific Basin and elsewhere break the post-Fukushima status quo of a tight market. The first signs of this change were apparent in 2014 as a looser supply-demand balance and the drop in oil prices in the second half of the year led to significant price movements. New LNG supplies combined with potential nuclear restarts in Japan and expected weaker economic growth in China will leave the Pacific Basin well-supplied, reducing the need for diversions from Atlantic Basin markets.

3.1. OVERVIEW

241.1 MT
Global LNG trade reached a near historical high in 2014

Total LNG trade reached 241.1 MT in 2014, up 4.3 MT from 2013. This marks the second largest year ever for LNG trade, falling just short of the post-Fukushima high of 241.5 MT set in 2011.

19 countries exported LNG in 2014, up from 17 in 2013. PNG's first liquefaction plant came online ahead of schedule, driving incremental growth in the market with output of 3.5 MT. After a year hiatus, the US also resumed LNG exports from Kenai LNG under a temporary production permit. As in 2013, a further eight countries re-exported cargoes in 2014, with Spain accounting for nearly 60% of the trade. Singapore and India joined the list in early 2015, both re-exporting their first cargo.

Historically, the majority of LNG production has come from the Asia Pacific region. However, the progressive build-up of Qatari capacity starting in the late 1990's allowed the Middle East to emerge as the largest exporting region in 2010. While Asia Pacific provided 31% of the world's LNG in 2014, Middle Eastern exports met 41% of total demand. Qatar alone exported nearly 77 MT or roughly one-third of global trade.

In 2014, 75% of all incremental supply growth came from the Pacific Basin. The start-up of PNG LNG along with stronger production from Australia and Malaysia more than balanced lower production out of Brunei and Indonesia, boosting total Pacific Basin supply by 3.2 MT.

Supply growth also came from the Atlantic Basin. New and more efficient liquefaction trains combined with lower pipeline exports supported higher Algerian LNG production for the first time in six years. While Nigeria also had a strong year, resuming stable production after a series of *force majeures* disrupted operations in 2013, Norway's Snøhvit LNG facility saw record production in 2014. These Atlantic Basin gains were somewhat offset by the sharp drop-off of Egyptian LNG exports due to severe and lasting feedstock shortages. Further, Angola LNG only added a few cargoes to the market as it was shut-down for extended repair work at the beginning of 2014.

On the demand side, only one new importer – Lithuania – entered the market in 2014, bringing the total number of importers to 29 (excluding Indonesia which has only

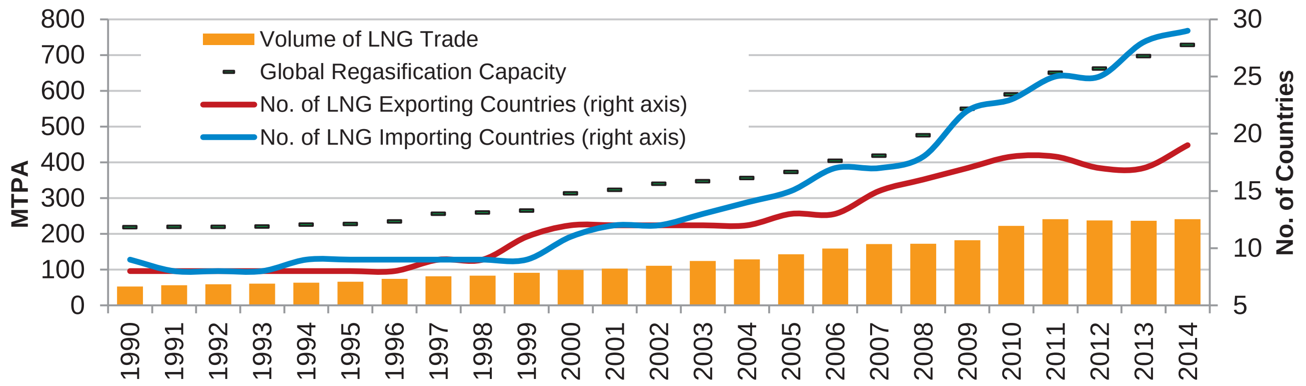


Figure 3.1: LNG Trade Volumes, 1990-2014

Source: IHS, IEA, IGU

received domestically-produced LNG). This is set to rise to 33 in 2015 with new regasification terminals in Jordan, Egypt, Pakistan and Poland, further diversifying the geographic spread of LNG importing countries.

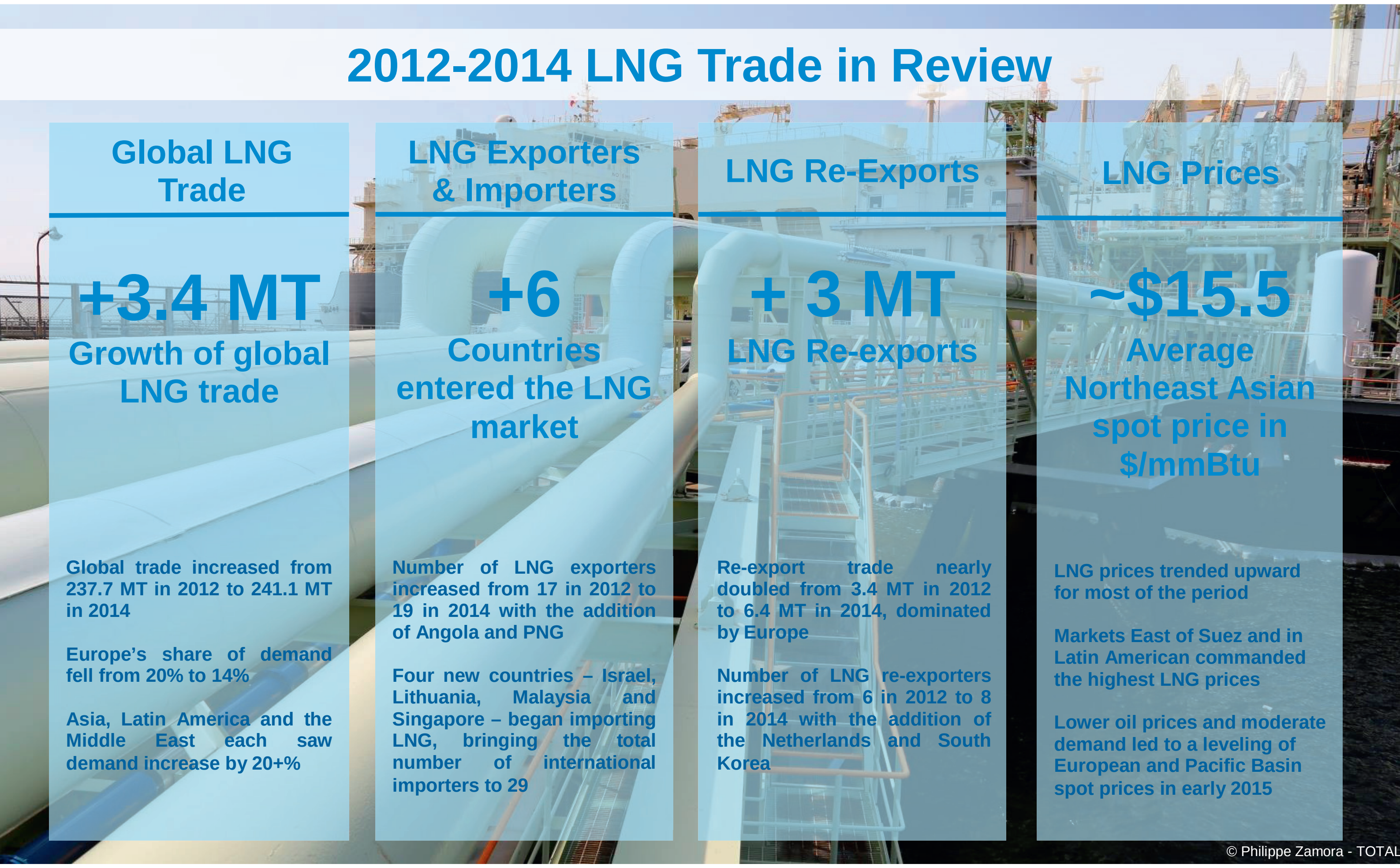
Eleven other countries became LNG importers between 2008 and 2013, including Brazil, Canada, Chile, Indonesia, Israel, Kuwait, Malaysia, the Netherlands, Singapore, Thailand and the UAE. Many of these countries were not considered potential LNG importers a decade ago and the US, which was then expected to be the largest LNG import market by now, has seen imports slow to a trickle. In some countries, such as Japan and South Korea, LNG is used to meet the entire gas need.

Asia and Asia Pacific markets (the distinction between these regions is illustrated in Section 12.3.) continue to dominate LNG imports at a combined 75% of global demand in 2014. For the second year in a row, the top five importers were all located in these two regions. Asia Pacific demand remained flat year-on-year (YOY) at 145.5 MT as import growth in Japan, Singapore and Taiwan was counterbalanced by a sizeable fall in South Korean imports. In Asia (+3.1 MT), growth was driven by India and China.

The most sizeable import declines came from Europe, particularly from lower demand in France, Italy and Spain. However, these declines were much more muted than in the previous two years, with growth in Turkish and UK imports limiting the fall in European demand to 0.8 MT. While Brazil registered the largest growth in the Americas as it continued to suffer the effects of a severe drought, Mexico remained the leading LNG market in the region. Even so, Latin American demand reached a high of 15.4 MT in 2014, nearly double North American imports.

Looking ahead, LNG demand trajectories for most importers are not expected to fundamentally change in 2015, even with lower oil prices. The Pacific Basin is set to remain the largest source of LNG demand, with China acting as the fastest growing market as contracted supplies from new Pacific Basin projects come online. Demand could, however, be somewhat tempered by potential nuclear restarts in Japan and expectations of slower economic growth in China. Further, European and North American LNG demand is likely to remain weak as gas market fundamentals reduce the need for LNG. Latin America will continue to figure as an attractive import market, with countries such as Argentina and Brazil offering premium prices for spot and short-term supplies.

Nevertheless, trade patterns will likely begin to shift in 2015 as new Pacific Basin supply – particularly from Australia – starts to enter the market, leaving Asia and Asia Pacific well-supplied. This, combined with downward pressure on LNG prices, may put an end to the growth of Middle East-Pacific and Atlantic-Pacific trade seen in recent years as more supplies are kept within the Atlantic Basin.



2012-2014 LNG Trade in Review

Global LNG Trade

+3.4 MT

Growth of global LNG trade

Global trade increased from 237.7 MT in 2012 to 241.1 MT in 2014

Europe's share of demand fell from 20% to 14%

Asia, Latin America and the Middle East each saw demand increase by 20+%

LNG Exporters & Importers

+6

Countries entered the LNG market

Number of LNG exporters increased from 17 in 2012 to 19 in 2014 with the addition of Angola and PNG

Four new countries – Israel, Lithuania, Malaysia and Singapore – began importing LNG, bringing the total number of international importers to 29

LNG Re-Exports

+ 3 MT

LNG Re-exports

Re-export trade nearly doubled from 3.4 MT in 2012 to 6.4 MT in 2014, dominated by Europe

Number of LNG re-exporters increased from 6 in 2012 to 8 in 2014 with the addition of the Netherlands and South Korea

LNG Prices

~$15.5

Average Northeast Asian spot price in $/mmBtu

LNG prices trended upward for most of the period

Markets East of Suez and in Latin American commanded the highest LNG prices

Lower oil prices and moderate demand led to a leveling of European and Pacific Basin spot prices in early 2015

3.2. LNG EXPORTS BY COUNTRY

Nineteen countries exported LNG in 2014, up from 17 in 2013. The biggest supply side change was the addition of PNG's first liquefaction plant. PNG LNG started operations earlier than expected and rapidly ramped up production, adding 3.5 MT to the market, all of which was delivered to Asia. After laying idle in 2013, the US' Kenai LNG plant produced 0.3 MT in 2014 after it received a two-year license to resume production.

For the ninth year in a row, Qatar remained the largest LNG exporter, providing 76.8 MT (-0.4 MT) to the market or approximately one-third of global supply. Malaysia and Australia – the world's second and third largest LNG producers (respectively) – saw LNG exports reach an all-time high. In Australia, higher exports were in large part the product of an improved feedstock situation at North West Shelf LNG and improved output from Pluto LNG. Elsewhere in Asia Pacific, however, exports declined, led by Indonesia (-1.0 MT) where feedstock issues persist and LNG production is increasingly diverted to the domestic market. Brunei also saw exports dip by 0.8 MT on the back of lower contracted volumes.

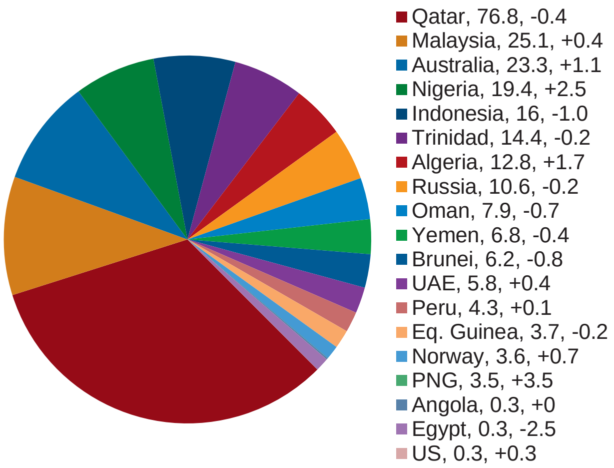


Figure 3.2: 2014 LNG Exports by Country & Incremental Change Relative to 2013 (in MTPA)

Sources: IHS, US DOE, IGU

Outside of Asia Pacific, several Atlantic Basin producers that have historically experienced variable LNG output had strong years in 2014. After PNG, the largest YOY gain globally was in Nigeria (+2.5 MT), which resumed stable operations after multiple instances of *force majeure* in 2013. In Algeria, LNG exports showed YOY growth for the first time since 2007 (+1.7 MT) as the country displaced pipeline exports to Europe. New liquefaction trains further supported LNG production: while the Skikda-GL1K Rebuild saw its first full year of operations, Algeria commissioned its newest train – Arzew-GL3Z – in November 2014. Similarly, Norwegian exports reached 3.6 MT (+0.7 MT), their highest level since the start of Snøhvit LNG in 2007 as the plant maintained high utilisation levels.

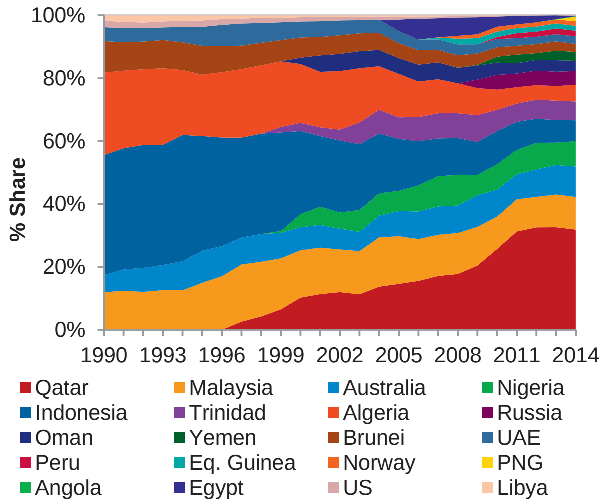


Figure 3.3: Share of Global LNG Exports by Country, 1990-2014

Sources: IHS, US DOE, IGU

In spite of this strong performance, production issues at several exporters kept additional supply off the market. Egypt continued to experience severe feedstock shortages due to declining domestic gas production and rapidly growing demand. While the Damietta LNG plant was shut down at the end of 2012, the Egyptian LNG (ELNG) facility sent out only six cargoes in 2014, leading exports to decline by 2.5 MT YOY. LNG production in Egypt is set to remain limited in the near-term as feedstock issues persist. In Angola, technical difficulties at the Angola LNG plant, commissioned in mid-2013, led the facility to be shut down in April 2014 for an extended period of repair work. The plant only exported five cargoes in 2014 (0.3 MT) and is not expected back online until late 2015 at the earliest.

Outside of the Atlantic Basin, significant export declines came from the Middle East, with Oman and Yemen seeing exports fall by a combined 1.2 MT. Yemen LNG further temporarily declared *force majeure* on LNG exports in January 2015 due to domestic unrest. However, the plant quickly resumed operations and brought forward planned maintenance work.

6.4 MT
Re-exported LNG volumes in 2014

As in 2013, eight countries – Belgium, Brazil, France, the Netherlands, Portugal, Spain, South Korea and the US – re-exported LNG. Total re-exports grew rapidly for the fifth consecutive year, reaching a new high of 6.4 MT in 2014 (+44% YOY). While South Korea and the Netherlands began re-exports in 2013, no new countries entered the market in 2014 despite approvals to do so in Canada and India. However, Singapore and India both re-exported their first cargoes in early 2015.

Europe continued to dominate reload activity as weak local gas demand encouraged the pursuit of arbitrage

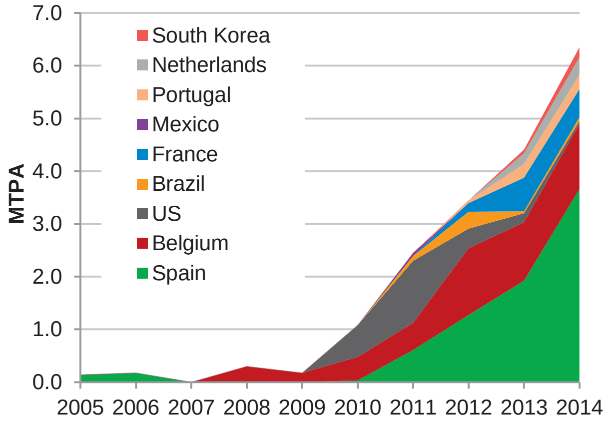


Figure 3.4: Re-Exports by Country, 2005-2014

Note: Re-exports figures include volumes that were reloaded and discharged within the same country.

Sources: IHS, US DOE

opportunities East of Suez and in Latin America. All but six re-exported cargoes (95% of re-exports) came from Europe, with Spain alone accounting for nearly 60% of the global total. Spanish re-exports reached an all-time high of 3.7 MT, up 90% YOY as cheap coal, more renewables and a weak economy weighed on gas demand. Spanish re-exports were further favoured by the development of re-export infrastructure at the Barcelona and Bilbao regasification terminals in 2014 – each of Spain's six terminals now has reload capabilities.

Looking ahead, however, the re-export trade may find it increasingly difficult to maintain its upward momentum as new LNG supplies enter the market and increase supply competition, potentially exerting pressure on spot prices and limiting arbitrage opportunities.

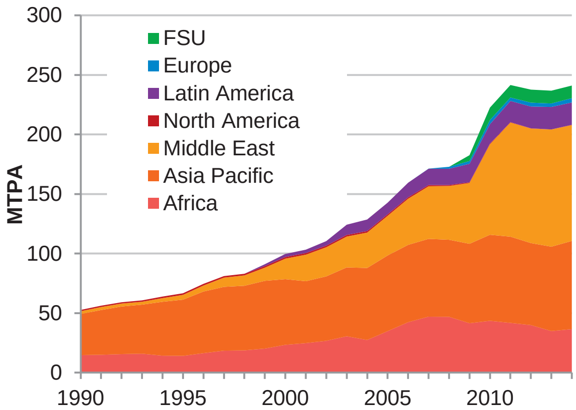


Figure 3.5: LNG Exports by Region, 1990-2014

Note: FSU = Former Soviet Union

Sources: IHS, US DOE, IGU

On a regional basis, LNG trade was primarily supported by export growth in Asia Pacific (+3.2 MT), where total exports reached 74 MT (+3.2 MT) in 2014 (31% of global supply). African LNG exports also rose by 1.6 MT YOY, with Africa maintaining a 15% global market share (36. 6 MT). Conversely, Middle Eastern LNG exports dipped by 1.2 MT in 2014, the first time the region contracted since the early 1990's. Still, the Middle East remained the largest exporting region by a sizeable margin, a position it has held since 2010 following the ramp-up of Qatari production. At 97.3 MT in 2014, the Middle East supplied over 40% of the global LNG market.

3.3. LNG IMPORTS BY COUNTRY

Twenty-nine countries imported LNG from the global market in 2014. Europe had the world's only new importer, Lithuania, which commissioned the Klaipeda terminal at the end of the year. However, four new countries – Jordan, Egypt, Pakistan and Poland – are expected to join the LNG market in 2015, bringing the number of international importers to 33.

Pipe on the Arwa Spirit LNG Tanker

Asia Pacific remained the dominant LNG market in 2014, consuming 60% of total LNG production. Japan is the largest market in the region (and globally), followed by South Korea and Taiwan. Asia narrowly outstripped Europe as the second largest LNG market for the first time in 2014, with China and India importing a combined 34.6 MT, just over 14% of global trade. European imports stood slightly lower at 33.0 MT, down nearly 50% from a peak of 65.6 MT in 2011.

Exporting Region / ***Importing Region***	Africa	Asia Pacific	Europe	FSU	Latin America	Middle East	North America	Re-exports Received	Re-exports Loaded	**Total**
Asia	3.2	9.7	0.2	0.1	0.2	20.5	-	0.6	-	**34.5**
Asia Pacific	13.0	63.8	0.4	10.5	0.9	54.4	0.3	2.4	(0.2)	**145.5**
Europe	15.3	-	1.9	-	3.5	17.7	-	0.6	(6.0)	**33.0**
L. America	2.7	-	0.9	-	8.4	1.2	-	2.1	(0.1)	**15.2**
Middle East	0.5	0.3	-	-	0.9	2.2	-	0.4	-	**4.3**
N. America	1.8	0.2	0.2	-	4.9	1.2	-	0.2	(0.1)	**8.4**
Total	**36.6**	**74.0**	**3.6**	**10.6**	**18.8**	**97.2**	**0.3**	**6.4**	**(6.4)**	**241.1**

Table 3.1: LNG Trade between Basins, 2014, MT

Sources: IHS, EIA, US DOE, IGU

In 2014, the world's five largest importers – Japan, South Korea, China, India and Taiwan – were located in Asia and Asia Pacific. China and India accounted for over 70% of all incremental demand growth, while South Korea observed the largest import decline globally. In India, lower rainfall in the monsoon season reduced hydropower availability and increased the call on gas-in-power, pushing up LNG imports by 1.7 MT YOY. Continued declines in domestic production further supported higher Indian LNG demand. China followed closely behind, with imports rising by 1.4 MT YOY, a moderate increase compared with 2013 when YOY imports rose by 3.8 MT. This more tempered growth can largely be attributed to fuel competition and China's economic slowdown in 2014. In turn, South Korean LNG demand dropped 2.8 MT in 2014. This was primarily the result of a mild 2013–14 winter, which left South Korea with sufficient storage, prompting a retreat from the spot market in mid-2014.

Japan – the world's single largest LNG market – saw LNG imports rise by 1.1 MT over 2013 levels. Japanese LNG demand has grown rapidly since the Fukushima nuclear disaster in March 2011, which led to the progressive shut-down of all of Japan's nuclear power plants and increased the call on LNG-in-power. After rising by over 8 MTPA in 2011-2012, LNG import growth slowed in 2013 (+0.5 MT) and 2014 due to the economic slowdown, increased energy efficiency and moderate temperatures in 2014. As of early 2015, all of the country's nuclear power plants remained offline, though four reactors had been cleared to restart operations. Still, the exact timeline for restarts remains unclear. Going forward, Japan's LNG demand will in large part be dictated by the pace of nuclear restarts, as well as the cost and availability of alternative energy sources.

European LNG demand continued to fall in 2014 on the back of gas to coal switching in power, higher renewable generation and stagnant economic conditions. However, consumption declined in a much more muted fashion than in 2012-13. While France, Italy and Spain each saw YOY imports dip by around 1 MT, growth in Turkey (+1.1 MT) and the UK (+1.6 MT) limited Europe's overall decline to just 0.8 MT. This compares to a drop of 14.6 MT in 2013 and 17.2 MT in 2012. In fact, the UK had the second-largest YOY growth globally after India as the result of Qatari deliveries. Imports into other European countries – Belgium, Greece, the Netherlands and Portugal – remained roughly flat YOY, while Lithuania imported its first two cargoes in November and December 2014.

Latin America – Argentina, Brazil, Chile, the Dominican Republic and Puerto Rico – consumed 15.4 MT in 2014 and increased its lead over North American LNG imports, which it has held since 2012. Brazil registered the only sizeable import growth (+1.3 MT) in the region. A severe, two-year drought has resulted in very low hydropower reserve levels and a higher call on LNG for power generation, pushing Brazilian LNG imports to a record 5.7 MT in 2014 (up from 0.6 MT in 2011).

Despite Brazil's strong growth, Mexico remained the largest market in the Americas at 6.9 MT (+0.9 MT) in 2014. Gas pipeline bottlenecks continued to drive increases in Mexican LNG imports to grid deficient areas, though incremental growth was more subdued than in 2013. Mexico now imports over four times more LNG than the US and Canada combined.

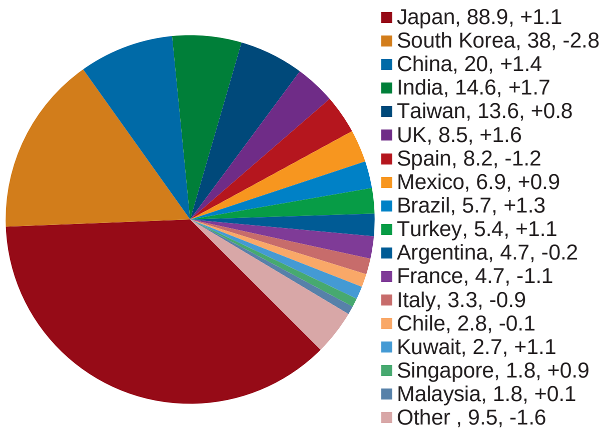


Figure 3.6: 2014 LNG Imports by Country & Incremental Change Relative to 2013 (in MTPA)

"Other" includes Belgium, Canada, the Dominican Republic, Greece, Israel, Lithuania, the Netherlands, Portugal, Puerto Rico, Thailand, the UAE and the US

Sources: IHS, US DOE, IGU

Middle Eastern LNG imports in 2014 reached 4.2 MT (+1.2 MT). Israel all but left the LNG market – it primarily aimed to use imports as a stop-gap solution before domestic production began in 2013. Kuwait more than made up for Israel's absence as a larger floating storage and regasification unit (FSRU) and new contracts allowed the country to grow imports by 65%.

+ 7% p.a.
Average yearly growth rate of LNG demand since 2000

On a global level, domestic production and pipeline volumes continue to account for the majority of global gas supplies, at 69% and 21% of the total (respectively). However, LNG has made rapid inroads over the past two decades. From just 4% in 1990, LNG now makes up 10% of global gas supply. LNG production has expanded by an average 7% per year since 2000, far faster than the 2% growth registered by domestic production and the 4% growth seen for pipeline gas.

In certain markets, LNG has been used to offset maturing domestic gas production and maintain supply. This has notably been the case for traditionally large gas producers such as Argentina, the Netherlands, the UAE and the UK. Other gas producing countries have turned to LNG to increase gas supply security. These include longstanding LNG importers such as Italy (whose supply is chiefly piped gas from North Africa) and Turkey (a key gas transit point from Central Asia to Europe that offtakes piped gas for domestic use), as well as newer LNG market entrants such as Thailand and Kuwait (where demand growth has surpassed gas production).

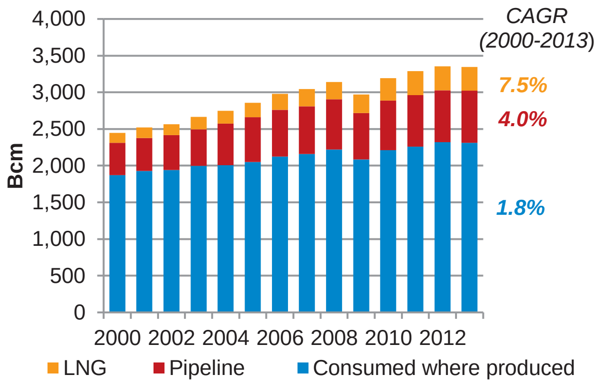


Figure 3.7: Global Gas Trade, 2000-2013

CAGR = Compound Annual Growth Rate

Sources: IHS, BP Statistical Review of World Energy

Asia Pacific countries are by far the most dependent on LNG imports to meet gas demand, more than double the gas supply share in Latin America and Europe. With little to no domestic production or pipeline import capacity, Japan, South Korea and Taiwan – the three most important LNG markets in Asia Pacific – rely on LNG to meet nearly 100% of gas demand.

RasGas Employee Inspecting Offshore Riser Platform Drain Manifold

Similarly, in Europe, Spain and Portugal have relied on LNG for nearly half of their gas supply over the last decade. Other markets without or with limited domestic production such as Belgium, Greece and France have also turned to LNG, chiefly to supplement pipeline imports.

Over the past few years, shifting market dynamics have changed the import requirements of several countries. The US shale revolution has allowed the US to become nearly self-sufficient in gas and sharply reduced the LNG requirements of Canada due to the interconnectedness of the North American grid. Though Mexican LNG imports have risen for the past three years, new midstream projects are set to allow for additional low-cost pipeline supplies from the US, pushing out LNG in years ahead.

Europe has also seen its LNG demand rapidly erode due to a prolonged period of economic stagnation, along with growing competition from coal and renewables in the power sector. Looking ahead, however, this could subside as uncontracted capacity additions make LNG supplies available to liquid markets.

In Asia and Asia Pacific, demand has proven to be resilient in the post-Fukushima era. Still, slower economic growth in China has already weighed on demand growth in 2014. While contracted supplies from new projects in the Pacific Basin have positioned China for strong LNG import growth in 2015-16, there remains some uncertainty as to China's ability to absorb the contracted supply ramp-up into its market. This could lead to additional volumes moving to the Atlantic Basin. Moreover, the speed and scope of Japan's return to nuclear power generation will be another major market driver over the next two years.

Finally, Latin America has picked up market share since 2009, rising from 1% of global demand to 6% in 2014. Latin America has surpassed North America as an LNG export destination since 2012 as low hydropower in Brazil led to a surge in LNG imports to meet demand for gas-in-power. Argentine LNG demand also reached nearly 5 MT for the second consecutive year in 2014 as the country sought to offset declining domestic production and limited pipeline imports from Bolivia. Higher residential gas prices and a somewhat improved domestic production picture could, however, limit Argentine LNG import growth in 2015.

3.4. LNG INTERREGIONAL TRADE

Intra-Pacific trade traditionally dominated the LNG market, accounting for over 70% of global trade in the first half of 1990's. However, new LNG exporters in the Middle East and Atlantic Basins have since entered the market, shifting global flows. The most remarkable shift has been the expansion of Middle East-Pacific trade, driven by the rise of Qatar as the world's largest LNG exporter. The flexibility of European supply contracts combined with the price spread between Asia and Europe has resulted in Qatari volumes flowing away from the Atlantic Basin to the Pacific Basin. Since 2013, Middle East-Pacific LNG flows have been roughly on par with Intra-Pacific exchanges at around one-third of global trade. Similarly, weak demand in Europe and North America has allowed Middle Eastern and Atlantic Basin cargoes to flow to Latin America.

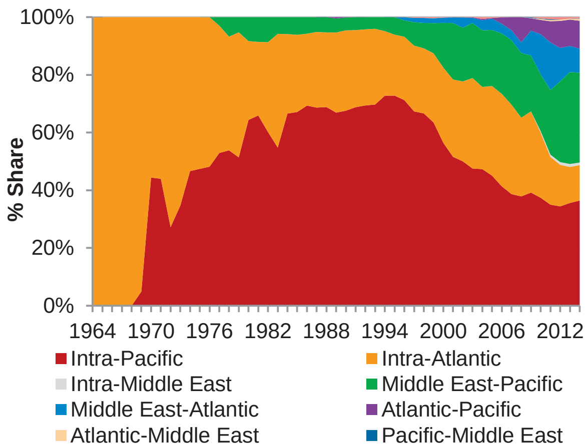


Figure 3.8: Inter-Basin Trade Flows 1964-2014

Sources: IHS, US DOE, IGU

Going forward, interregional trade patterns are set to see further shifts. New production from PNG already had a significant influence on trading patterns in 2014. Intra-Pacific trade experienced the largest increase of any flow at +3.3 MT, more than double any other route. The continued ramp-up of Asia Pacific production (particularly in Australia) in 2015-2017 will leave the Pacific Basin well-supplied, likely pushing more Atlantic and Middle Eastern volumes into Atlantic and Mediterranean markets. This will be supported by the addition of Lithuania as an LNG importer in late 2014, followed by Jordan, Egypt and Poland in 2015. Next decade, the emergence of new LNG plays in North America, East Africa and Russia has the potential to further alter inter-basin supply dynamics.

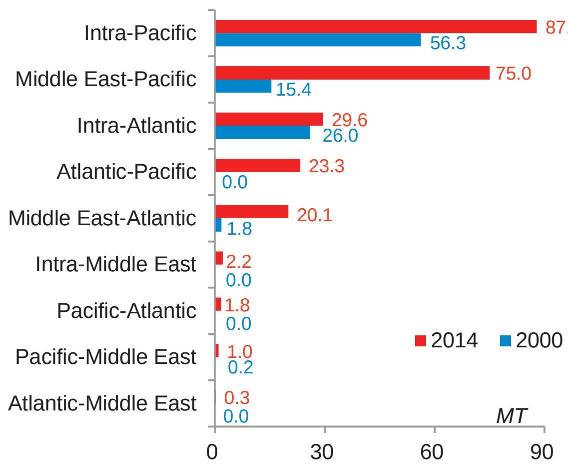


Figure 3.9: Inter-Basin Trade, 2000 v. 2014

Sources: IHS, IGU

	Algeria	Angola	Australia	Brunei	Egypt	Equatorial Guinea	Indonesia	Malaysia	Nigeria	Norway	Oman	PNG	Peru	Qatar	Russia	Trinidad	UAE	US	Yemen	Re-exports Received	Re-exports Loaded	2014 Net Imports	2013 Net Imports	2012 Net Imports	2011 Net Imports
China	0.32	0.13	3.93	0.06	0.13	0.77	2.46	2.89	0.43	0.13	0.13	0.27	-	6.67	0.13	0.13	-	-	1.07	0.34	-	19.98	18.60	14.77	12.84
India	0.14	-	-	-	-	-	-	0.06	1.33	0.05	0.10	-	-	12.03	-	0.06	0.10	-	0.45	0.28	-	14.59	12.92	13.99	12.74
Asia	0.46	0.13	3.93	0.06	0.13	0.77	2.46	2.95	1.75	0.18	0.22	0.27	-	18.70	0.13	0.19	0.10	-	1.52	0.62	-	34.57	31.52	28.76	25.58
Japan	0.74	0.06	18.28	4.47	0.07	0.91	5.77	15.26	4.83	0.29	3.45	2.19	0.07	16.15	8.32	0.18	5.63	0.25	0.98	0.97	-	88.90	87.79	87.26	78.76
Malaysia	0.32	-	0.06	0.26	0.07	-	-	0.12	0.26	0.06	-	-	-	0.07	-	-	-	-	0.40	0.13	-	1.76	1.62	-	-
Singapore	-	-	-	-	-	1.34	0.07	-	-	-	-	-	-	-	-	0.30	-	-	-	0.14	-	1.85	0.94	-	-
South Korea	0.38	0.07	0.84	0.76	0.07	0.13	5.29	3.68	3.34	0.07	3.89	-	0.08	13.12	2.00	0.13	0.06	-	3.19	1.10	(0.19)	38.02	40.86	36.78	35.73
Taiwan	0.06	-	0.13	0.62	-	0.07	2.13	2.85	0.12	-	0.13	1.03	-	6.08	0.06	0.06	-	-	0.19	0.06	-	13.60	12.83	12.78	12.18
Thailand	-	-	-	-	-	-	-	-	0.14	-	0.07	-	-	0.94	0.06	0.06	-	-	0.07	-	-	1.33	1.42	0.98	0.72
Asia-Pacific	1.50	0.13	19.32	6.11	0.20	2.46	13.26	21.91	8.69	0.43	7.53	3.22	0.15	36.36	10.46	0.74	5.69	0.25	4.83	2.41	(0.19)	145.47	145.46	137.80	127.40
Belgium	0.01	-	-	-	-	-	-	-	-	-	-	-	-	2.12	-	-	-	-	-	-	(1.23)	0.90	1.10	1.91	4.45
France	3.33	-	-	-	-	0.07	-	-	0.85	0.07	-	-	0.06	0.75	-	0.06	-	-	-	0.06	(0.53)	4.72	5.80	7.48	10.68
Greece	0.34	-	-	-	-	-	-	-	-	0.05	-	-	-	-	-	-	-	-	-	0.04	-	0.43	0.51	1.07	0.95
Italy	0.05	-	-	-	-	-	-	-	-	-	-	-	-	3.16	-	0.06	-	-	-	0.07	-	3.35	4.25	5.23	6.43
Lithuania	-	-	-	-	-	-	-	-	-	0.11	-	-	-	-	-	-	-	-	-	-	-	0.11	-	-	-
Netherlands	-	-	-	-	-	-	-	-	-	0.53	-	-	-	0.09	-	0.19	-	-	-	-	(0.34)	0.47	0.32	0.61	0.56
Portugal	0.07	-	-	-	-	-	-	-	0.35	0.06	-	-	-	0.54	-	0.18	-	-	-	0.06	(0.27)	0.98	1.32	1.66	2.21
Spain	3.73	-	-	-	-	-	-	-	2.14	0.85	0.12	-	0.94	2.29	-	1.59	-	-	-	0.19	(3.66)	8.19	9.36	14.22	17.22
Turkey	3.04	-	-	-	-	-	-	-	1.08	0.20	-	-	-	0.81	-	0.06	-	-	-	0.19	-	5.38	4.24	5.74	4.58
UK	0.19	-	-	-	-	-	-	-	0.06	-	-	-	-	7.84	-	0.38	-	-	-	-	-	8.47	6.84	10.45	18.63
Europe	10.74	-	-	-	-	0.07	-	-	4.48	1.87	0.12	-	0.99	17.61	-	2.52	-	-	-	0.61	(6.03)	32.98	33.74	48.37	65.72
Argentina	-	-	-	-	-	-	-	-	0.61	0.12	-	-	-	0.68	-	2.51	-	-	-	0.82	-	4.73	4.93	3.82	3.19
Brazil	0.06	0.07	-	-	-	0.34	-	-	1.41	0.69	-	-	-	0.44	-	1.49	-	-	-	1.27	(0.07)	5.71	4.44	2.52	0.62
Chile	-	-	-	-	-	0.06	-	-	-	-	-	-	-	0.06	-	2.66	-	-	-	-	-	2.78	2.86	3.03	2.80
Dominican Republic	-	-	-	-	-	-	-	-	-	-	-	-	-	0.06	-	0.86	-	-	-	-	-	0.92	1.09	0.96	0.72
Puerto Rico	-	-	-	-	-	-	-	-	0.17	0.06	-	-	-	-	-	0.93	-	-	-	0.06	-	1.21	1.20	0.97	0.54
Latin America	0.06	0.07	-	-	-	0.40	-	-	2.19	0.88	-	-	-	1.24	-	8.44	-	-	-	2.15	(0.07)	15.35	14.51	11.30	7.88
UAE	-	-	0.07	-	-	-	-	0.06	0.12	-	-	-	-	1.02	-	-	-	-	0.07	0.06	-	1.39	0.41	-	-
Israel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.13	-	-	-	-	-	0.13	1.56	2.11	2.42
Kuwait	-	-	-	-	-	-	-	0.14	0.39	-	0.03	-	-	0.88	-	0.73	-	-	0.20	0.33	-	2.70	1.08	1.24	1.18
Middle East	-	-	0.07	-	-	-	-	0.20	0.51	-	0.03	-	-	1.90	-	0.86	-	-	0.27	0.39	-	4.23	3.06	3.35	3.61
Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.42	-	-	-	-	-	0.42	0.75	1.28	2.42
Mexico	-	-	-	-	-	-	0.25	-	1.82	0.12	-	-	3.19	1.00	-	0.36	-	-	-	0.13	-	6.87	5.97	3.55	2.92
US	-	-	-	-	-	-	-	-	-	0.11	-	-	-	-	-	0.89	-	-	0.17	0.06	(0.06)	1.17	1.83	3.26	5.93
North America	-	-	-	-	-	-	0.25	-	1.82	0.24	-	-	3.19	1.00	-	1.67	-	-	0.17	0.18	(0.06)	8.47	8.54	8.09	11.27
2014 Exports	12.76	0.34	23.31	6.17	0.33	3.70	15.97	25.07	19.44	3.60	7.91	3.49	4.33	76.82	10.59	14.42	5.80	0.25	6.78	6.35	(6.35)	241.07			
2013 Exports	10.90	0.33	22.18	7.05	2.81	3.89	17.03	24.68	16.89	2.97	8.63	-	4.26	77.18	10.76	14.63	5.40	-	7.23	4.59	(4.59)		236.83		
2012 Exports	11.03	-	20.78	6.85	5.08	3.75	18.12	23.11	19.95	3.41	8.08	-	3.89	77.41	10.92	14.40	5.57	0.19	5.13	3.45	(3.45)			237.67	
2011 Exports	12.59	-	19.19	6.84	6.42	3.89	21.43	24.99	18.75	2.86	7.90	-	3.76	75.49	10.49	13.94	5.85	0.33	6.65	2.33	(2.33)				241.45

Table 3.2: LNG Trade Volumes between Countries, 2014 (in MTPA)

Note: Indonesia conducted domestic LNG trade in 2012- 2014. This is therefore not included above as it does not reflect an international trade between countries.

Sources: IHS, US DOE, IGU

3.5. SPOT, MEDIUM AND LONG-TERM TRADE[1]

Historically, the vast majority of LNG was traded under long-term, fixed destination contracts. In the last decade, however, the expiration of several long-term contracts, the growth of flexible destination supplies, the proliferation of portfolio players and a range of other factors have led to the emergence of new contractual trade arrangements.

64.7 MT
Spot and short-term trade in 2014; 27% of total trade

One of the most fundamental changes has been the growing market for spot and short-term LNG (referred to as "spot"), here defined as all volumes traded under agreements of less than two years. While accounting for less than 5% of volumes traded in 2000, spot trade surpassed 60 MT in 2011. It has since fluctuated from 60-70 MT and stood at 64.7 MT in 2014, or 27% of global trade.

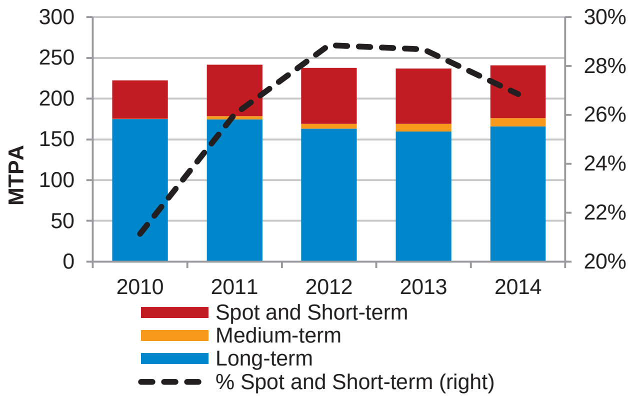


Figure 3.10: Short, Medium and Long-Term Trade, 2010-2014

Sources: IHS, US DOE, IGU

Trades under medium-term contracts (between 2 and <5 years) have also grown rapidly in the last five years. This has been driven in part by growing buyer hesitance to sign long-term contracts in the hope of securing more favourable contractual terms, and based on the view that the LNG market will loosen in the second half of the decade. Medium-term contracts have also been particularly useful for markets lacking a clear visibility on their longer-term LNG needs, but wishing to lock-in multi-year supplies.

Still, medium-term contracts remain marginal relative to spot volumes. Medium-term term trade expanded from under 1 MT in 2010 to over 10 MT in 2014. Total "non long-term" trade[2] reached 75.0 MT in 2014 or 31% of global trade.

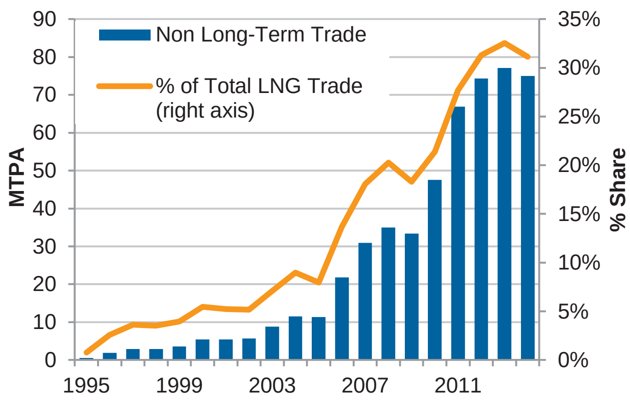


Figure 3.11: Non Long-Term Volumes, 1995-2014

Sources: IHS, US DOE, IGU

A number of key factors have contributed to the rapid growth of non long-term trade in recent years:

- The growth in LNG contracts with destination flexibility, chiefly from the Atlantic Basin and Qatar, which has facilitated diversions to higher priced markets.
- The increase in the number of exporters and importers, which has amplified the complexity of the trade and introduced new permutations and linkages between buyers and sellers. In 2014, 26 countries (including re-exporters) exported spot volumes to 28 end-markets. This compares to 6 spot exporters and 8 spot importers in 2000.
- The lack of domestic production or pipeline imports in Japan, South Korea and Taiwan, which has pushed these countries and others to rely on the spot market to cope with any sudden changes in demand like the Fukushima crisis.
- The surge in global regasification capacity.
- The large increase in demand in Asia and in emerging markets such as Southeast Asia and Latin America, which accelerated tightness in the LNG market.
- The decline in competitiveness of LNG relative to coal (chiefly in Europe) and shale gas (North America) that has freed up volumes to be re-directed elsewhere.
- The large disparity between prices in different basins, which made arbitrage an important and lucrative monetisation 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).

[1] *As defined in Section 12.2.*
[2] *"Non long-term" trade refers to all volumes traded under contracts of less than 5 years duration (spot/short-term + medium-term trade)*

The total volume of LNG traded on a spot basis declined slightly in 2014 relative to 2012-13, falling by just over 3 MT. Sizeable growth in spot supplies came from the commissioning of PNG LNG mid-year, which sold more than 2 MT on the spot market. Though most of these volumes were sold prior to the start-up of the project's long-term contracts, PNG LNG marketed spot cargoes throughout the year. Spot trade was further supported by higher output in Australia and Algeria, which added a combined 1 MT to the market. Spanish re-exports also boomed as companies sought to maximize arbitrage opportunities.

However, these gains were counterbalanced by lower exports from Brunei, Egypt and Equatorial Guinea, each of which saw spot exports decline by 1-2 MT. Further downward pressure came from Peru LNG (-1.2 MT) as the project's long-term supply contract with Mexico continued to ramp-up. While spot exports also fell in Trinidad (-1.8 MT) and Qatar (-0.6 MT), this was primarily the result of higher volumes from both countries being marketed under medium-term contracts.

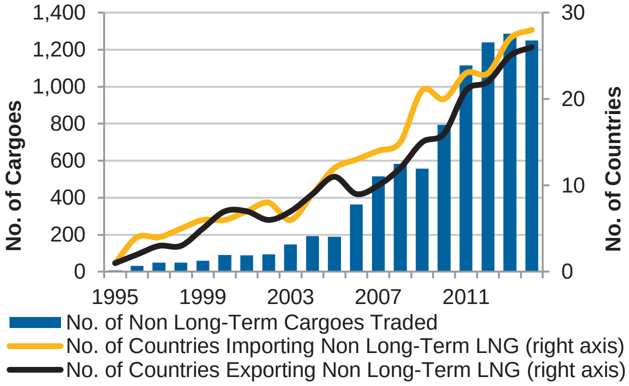


Figure 3.12: Non Long-Term Cargo Market Development, 1995-2014

Sources: IHS, US DOE, IGU

On the demand side, 17 countries purchased more spot LNG in 2014 than in 2013. India and Brazil led the way, importing 1.7 MT and 1.5 MT (respectively) more than in 2013. Higher spot imports in Brazil were due to low rainfall, which limited hydropower output and increased the call on LNG for power generation. In India, spot LNG imports counterbalanced declining domestic production. With all of its nuclear capacity still offline, Japan also saw a marginal increase in spot demand (+0.5 MT). Turkey (+0.8 MT), again partially due to low hydropower availability, and Puerto Rico (+0.6 MT) also experienced notable spot import growth compared to 2013 levels.

This growth was more than offset by lower imports into South Korea, Argentina and Mexico. The drop in South Korea was by far the most pronounced, with spot imports falling by 5.7 MT (down more than 50% YOY) as mild weather and high storage levels prompted a retreat from the market in the second and third quarter. In Argentina, spot purchases fell by nearly 3 MT as the country received the majority of its cargoes under a two-year tender signed in late 2013. Finally, Mexico's spot imports fell by 0.8 MT as more supplies were delivered under its long-term contract with Peru.

3.6. LNG PRICING OVERVIEW

Pricing in world gas markets remains very fragmented, with prices driven more by local and regional factors than global dynamics. Gas prices in North America are largely set at liquid trading hubs, the largest and most important of which is Henry Hub in Louisiana. In Europe, wholesale gas is sold mainly via long-term contracts. These contracts variously take into account hub-based or oil-linked pricing, and often both. In Asia and many emerging markets without established and liquid gas trading markets, the price of LNG is for the most part set via oil-linkages.

Pricing differentials between these regions have been relatively stable since 2011. However, changing dynamics which took root in the second half of 2014 – markedly the fall in oil prices and increased LNG availability – are set to have a strong impact on gas markets in the years ahead.

Over the past five years, the sustained growth of shale gas production in North America has seen Henry Hub almost exclusively traded at a discount to most other major gas benchmarks in the Pacific Basin and Europe. The discount widened in 2010-2011 and by April 2012, when Henry Hub bottomed-out at $1.9/mmBtu, stood at~$8-10/mmBtu relative to Europe and up to $14/mmBtu relative to Asia Pacific. A rebound in US prices in 2013 and into 2014 narrowed these differentials, especially compared to Europe. Cold temperatures drove Henry Hub to $5.9/mmBtu in February 2014, the highest level since June 2010, thinning the spread with Europe to around $4/mmBtu. However, the higher Henry Hub rate prompted a production response which saw the US price fall progressively throughout the rest of the year to a low of $3.4/mmBtu in December 2014.

In Asia and Asia Pacific, the majority of LNG demand is met by long-term oil-indexed contracts and complemented by spot imports to meet demand fluctuations. Following the events of the Fukushima disaster and the rise of global oil price benchmarks, oil-linked and spot prices rose rapidly. Prices have further been reinforced by limited supply availability and by competitive substitution in some markets between oil and gas in end use.

Despite signs of weaker LNG prices into Japan in the fourth quarter, the country continued to pay high prices in 2014, with average monthly LNG imports hovering between $15 and $16/mmBtu. Similarly, in the first half of 2014, Northeast Asian spot prices [3] averaged over

[3] *Northeast Asian spot prices are calculated based on the observed average price for spot cargoes imported into Japan and South Korea in a given month.*

$17/mmBtu. This compares to $16.4/mmBtu in 2013 and $15.2/mmBtu in 2012.

However, two effects took shape in the second half of 2014 that broke the status quo, putting downward pressure on spot prices. The first effect was the coincidence of weaker demand in Asia Pacific – driven by mild weather in Northeast Asia and slowing economic growth in China – with stronger Pacific Basin supply due to the ramp-up of PNG LNG in Q3 2014. These two drivers helped to push spot prices in Northeast Asia down to $10.8/mmBtu in September, a level not seen since before the Fukushima crisis in 2011 and some $4/mmBtu below the average import price into Japan. Northeast Asian spot prices have since rallied, but the Q4 2014 average of $13.5/mmBtu was still below the Q4 2013 average of $16.8/mmBtu.

The second market effect was the oil price decline that began in September 2014. From an average of over $100/bbl in the first eight months of 2014, crude prices fell rapidly to below $50/bbl in January 2015. Given that most oil-indexed contracts have a three to six month time lag against the oil price, Asian term import prices remained relatively steady through the end of 2014, with Japanese imports holding at the $15/mmBtu level. However, the oil price decline is set to filter through into delivered LNG prices for long-term contracted LNG.

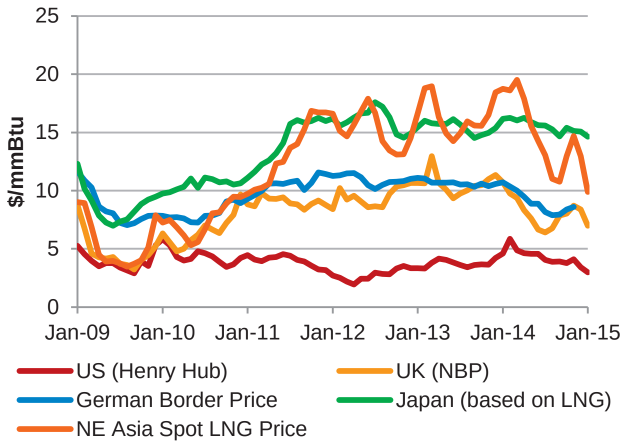


Figure 3.13: Monthly Average Regional Gas Prices, 2009 - January 2015

Sources: IHS, Cedigaz, US DOE

In recent years, Asian buyers have become increasingly vocal about shifting away from the traditional, fixed-destination, long-term, oil-linked LNG contract. Japanese, South Korean and Indian companies have markedly increased their interest in US LNG, signing several offtake agreements based on Henry Hub pricing. However, a lower priced oil environment may alter the economic rational driving buyers to secure US LNG contracts. While Henry Hub linked LNG contracts will continue to offer buyer's portfolio diversification the perception that these contracts will result in lower priced LNG relative to oil-linked contracts is less assured.

While low-oil prices have impacted and will continue to affect gas production in the US, overall market fundamentals are expected to play a more important role in driving US gas prices in the years ahead. Lower activity in oil and wet gas plays resulting from weaker oil prices is set to reduce the growth of associated gas production. However, this effect will be minimal relative to the size of US gas production. Moreover, reduced liquids activity has and will continue to reduce the costs of rigs, crews, and equipment, which will benefit operators. Because Henry Hub prices are expected to follow supply and demand fundamentals, US LNG contracts may offer buyers reduced price volatility over the next few years.

In Europe, the majority of gas contracts are indexed with a six to nine month lag to crude and fuel oil, though the region has increasingly moved towards a hybrid pricing system (particularly in the Northwest). This trend, which originally emerged in reaction to the drop in gas demand in 2009, involves the incorporation of trading hub pricing into pipeline gas prices. Under pressure from European buyers, major gas suppliers including Gazprom and Statoil have since increased the share of hub pricing in the formulation of pipeline export prices for certain contracts.

After fluctuating in the $10-11/mmBtu range in 2013, the German border gas price – a proxy for contracted gas import prices – came under pressure in 2014. The average border price fell consistently throughout the year, from $10.7/mmBtu in January to around $8/mmBtu at year-end. Given the lag to oil built into European gas contracts, the price softening did not reflect oil price weakness but rather the greater presence of European hub indexing. However, as with term LNG contracts in Asia, the lower oil price will weigh on the German border price in 2015.

One of Europe's most liquid trading hub, the National Balancing Point (NBP), saw gas prices decline in the first seven months of 2014. From a high of nearly $11/mmBtu in January 2014, the NBP fell off sharply to a low of $6.4/mmBtu in July, the lowest monthly price level since September 2010. The price decline was due both to a temperate 2013-2014, which left gas in storage at above-average levels, as well as the influx of Qatari LNG cargoes. Prices recovered with the onset of winter, ending the year at $8.50/mmBtu. This coincided with the September dip in Northeast Asian spot prices, reducing the differential with NBP to just $2.9/mmBtu. Though this differential rapidly returned to above $4/mmBtu from October through the end of the year, a looser LNG market and low oil prices could put further pressure on Northeast Asian prices in 2015.

Looking Ahead:

New LNG supplies are set to enter the market in 2015-16 and beyond. *Over the past four years, limited supply additions have combined with growing demand to maintain a tight LNG market. However, the tides started to shift in 2014 with the inauguration of PNG LNG and QCLNG, the first two of a wave of projects expected online in the next three years. Australian projects alone are set to add a further 58 MT of nominal capacity to the market by 2017, with sizeable volumes also coming from the US, Southeast Asia, Africa and elsewhere. These new supplies could leave the market well-supplied, increase market liquidity and progressively bring an end to the post-Fukushima status quo.*

Will LNG demand growth in the Pacific Basin be sustained? *In 2014, the Asia and Asia Pacific regions accounted for 75% of global demand and over 70% of incremental import growth. While the restart of nuclear reactors in South Korea and eventually in Japan will likely put downward pressure on LNG demand, China and India are primed to drive import growth in the years ahead. In China, this will be compelled by the influx of contracted supplies from new Pacific Basin projects, though slower economic growth and fuel competition could dampen the country's ability to absorb new supplies. In India, the poor outlook for domestic production will be the driving force, pushing the country to import higher volumes of LNG to balance its gas market. However, the sustained low price of coal – which remains from an economic point of view the strongest competitor of LNG in Asia – may well dampen the future trend of LNG usage for power.*

How will the arrival of new LNG importing countries in 2015 impact global demand? *In addition to Lithuania, which inaugurated its first regasification terminal in late 2014, four other countries – Egypt, Jordan, Pakistan and Poland – are scheduled to enter the LNG market in 2015. Combined, these five countries will add over 15 MT of import capacity. While only a few firm supply contracts have been signed with these markets, there remains considerable upside demand potential, especially for flexible LNG available from various sources. This is particularly true for Egypt, which is suffering from growing gas shortages. Until recently an LNG exporter, Egypt is now set to become Africa's first LNG importer.*

Arrival in Japan of the Arwa Spirit Vessel, Delivering a Cargo from Yemen LNG.

4. Liquefaction Plants

Having remained relatively stable since 2011, global liquefaction capacity increased by 10.5 MTPA in 2014, the result of three projects coming online. Capacity will grow significantly over the next several years, as 128 MTPA of projects were under construction as of the first quarter of 2015 – mostly in Australia and the US. However, only a few LNG proposals are likely to be sanctioned in 2015 due to the forecasted loosening of the global LNG market in the medium-term, as well as the financial difficulties caused by declining oil prices.

Though Qatar remains the largest liquefaction capacity holder, Australia has 57.6 MTPA of capacity under construction and is expected to gain the lead in 2017. The majority of new LNG proposals stem from the US and Canada, where a combined 614.9 MTPA of capacity has been announced. With four projects totalling 44.1 MTPA already under construction, capacity in the US will expand greatly over the next five years Yet most projects in the US and Canada are not expected to materialise due to a loosening global LNG market and high estimated project costs. Greenfield proposals in East Africa and elsewhere face similar challenges in the medium-term.

4.1. OVERVIEW

301.2 MTPA
Global liquefaction capacity, end-2014

Global nominal liquefaction capacity stood at 301.2 MTPA at the end of 2014, up from 290.7 in 2013. Two new projects were brought online: the 6.9 MTPA PNG LNG project in Papua New Guinea and the first 4.3 MTPA train of the QCLNG plant in Australia. Another 4.7 MTPA expansion train at the Arzew/Skikda complex in Algeria was also brought online. In Alaska, Kenai LNG temporarily re-started operations in early 2014 at partial capacity.

Beyond these additions, the final two trains at Arun LNG (totalling 3.3 MTPA) in Indonesia were taken offline in late 2014. The project, which began production in the late 1970s, is now fully decommissioned.

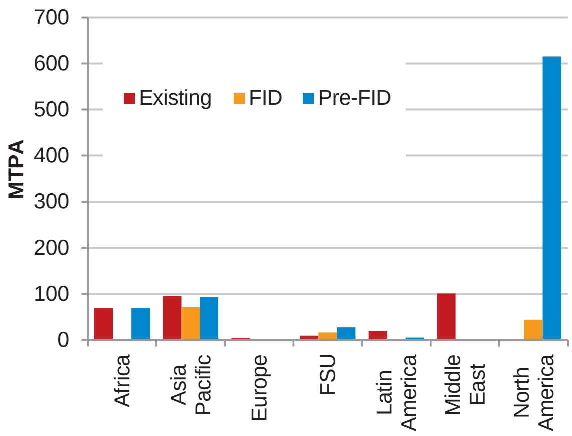


Figure 4.1: Nominal Liquefaction Capacity by Status and Region, as of Q1 2015

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 report.

Sources: IHS, Company Announcements

The amount of proposed liquefaction capacity globally has increased dramatically over the past few years, now totalling 836 MTPA. The bulk of the capacity (74%) has been proposed in the US and Canada. Many of these projects face considerable obstacles and have garnered limited commercial momentum. Only 30% of proposed capacity is at the pre-FEED stage or beyond.

128.1 MTPA
Global liquefaction capacity under construction, Q1 2015

128.1 MTPA of LNG capacity was under construction as of the first quarter of 2015. Several projects are expected to come online in 2015 in Australia, Malaysia, Indonesia and offshore Colombia. Based on announced start dates, the nominal capacity totals 35.9 MTPA, though delays may still be announced.

In 2014, four projects (27.6 MTPA of capacity) reached a Final Investment Decision (FID). Three – Cameron LNG, Cove Point and Freeport LNG – are in the US. The fourth was PETRONAS FLNG (PFLNG) 2 in Malaysia.

Other projects faced outages. Both liquefaction projects in Egypt remain mostly offline due to feedstock shortages. In Yemen, LNG production was disrupted in early 2015 and is at risk of further outage as a result of political instability.

Still, growth will accelerate starting in 2015 as a series of under construction projects in Australia and the first of the US projects come on-stream. With 57.6 MTPA under construction, Australia is likely to become the largest liquefaction capacity holder in 2017. Growth in the US will follow a few years behind Australia, with 44.1 MTPA already under construction and additional capacity likely to be sanctioned in 2015.

Significant liquefaction capacity has also been proposed in Western Canada, East Africa and Russia. However, timelines for projects in these regions have generally been pushed back due to multiple converging trends. These include the forecasted loosening of the global LNG market, high estimated project costs and competitive pressure driven by low oil prices. Many companies are looking to reduce spending and, over the next few years, project developers may hesitate to commit to costly liquefaction projects in frontier regions.

4.2. GLOBAL LIQUEFACTION CAPACITY AND UTILISATION

Global nominal liquefaction capacity stood at 301.2 MTPA at the end of 2014 and was utilised at an average 81% throughout the year.

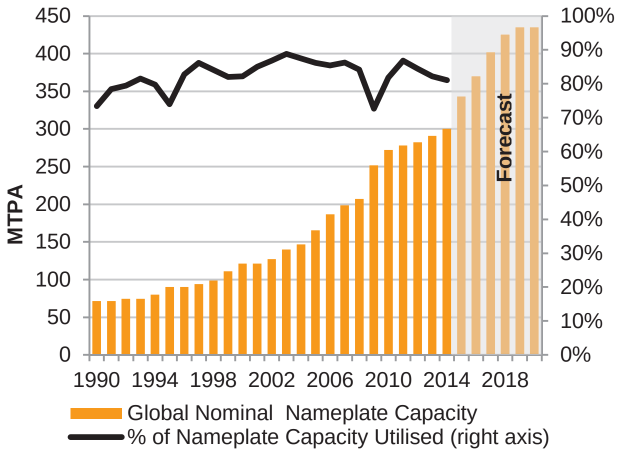


Figure 4.2: Global Liquefaction Capacity Build-Out, 1990-2020

Sources: IHS, Company Announcements

This is largely consistent with the past few years. Since 2010, global liquefaction capacity utilisation has averaged 83%. The slightly lower rate in 2014 was driven by reduced operations at Egypt's second liquefaction project, ELNG, starting in early 2014. Damietta LNG was already offline, and the country operated at only 3% utilisation for the year. No timeline has been established for the resumption of higher Egyptian exports. Further, in Angola, the 5.2 MTPA project experienced a series of technical difficulties and produced only a few cargoes before being taken offline for repairs. Output from Algeria increased from 10.9 MT in 2013 to 12.8 MT in 2014, but overall utilisation remained relatively low, at 48% on the year.

These losses were partially replaced by higher utilisation in Nigeria and Norway, as well as continued strong output from Qatar, Russia and Malaysia – all of which operated near full capacity in 2014.

4.3. LIQUEFACTION CAPACITY AND UTILISATION BY COUNTRY

Existing

Nineteen countries held active LNG export capacity at the end of 2014, with PNG being the newest addition to the list. Nearly two-thirds of the world's capacity is held in just five countries: Qatar, Indonesia, Australia, Malaysia and Nigeria. Qatar alone holds 26% of the total. Relatively few projects are expected to be decommissioned in the near-term. Only Arun LNG in Indonesia (decommissioned in late 2014), Kenai LNG in the US (scheduled for shut-down in 2016) and aging plants in Algeria are expected to be taken offline in the next few years. However, all three countries will remain exporters, with several other projects online in Indonesia and Algeria, and under construction in the US.

+ 40% by 2020
Expected growth in global liquefaction capacity

Under Construction

Worldwide, 128.1 MTPA of liquefaction capacity was under construction as of the first quarter of 2015. The majority of capacity is being constructed in Australia (57.6 MTPA) and the US (44.1 MTPA). Additional projects are under construction in Russia (16.5 MTPA), Malaysia (7.0 MTPA), Indonesia (2.5 MTPA) and Colombia (0.5 MTPA).

Australia is already a major source of LNG – in 2014, it was the third largest LNG capacity holder, behind Qatar and Indonesia. It will be the predominant source of new liquefaction capacity over the next five years. Seven projects are under construction in the country and all are expected online before 2018.

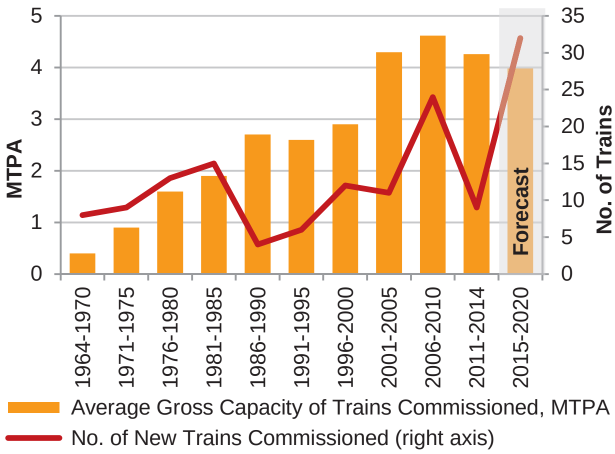


Figure 4.3: Number of Trains Commissioned vs. Average Train Capacity, 1964-2020

Sources: IHS, Company Announcements

Four projects are under construction in the US, three of which were sanctioned in the second half of 2014. All four projects are brownfield developments associated with existing regasification terminals. The bulk of capacity is being built on the Gulf Coast. The US also brought Kenai LNG back online in early 2014. The Alaskan project had been shut-down in 2012 due to declining feedstock, but was granted a two-year permit by the US Department of Energy (DOE) to operate at partial capacity. It would need additional approval to operate beyond 2016.

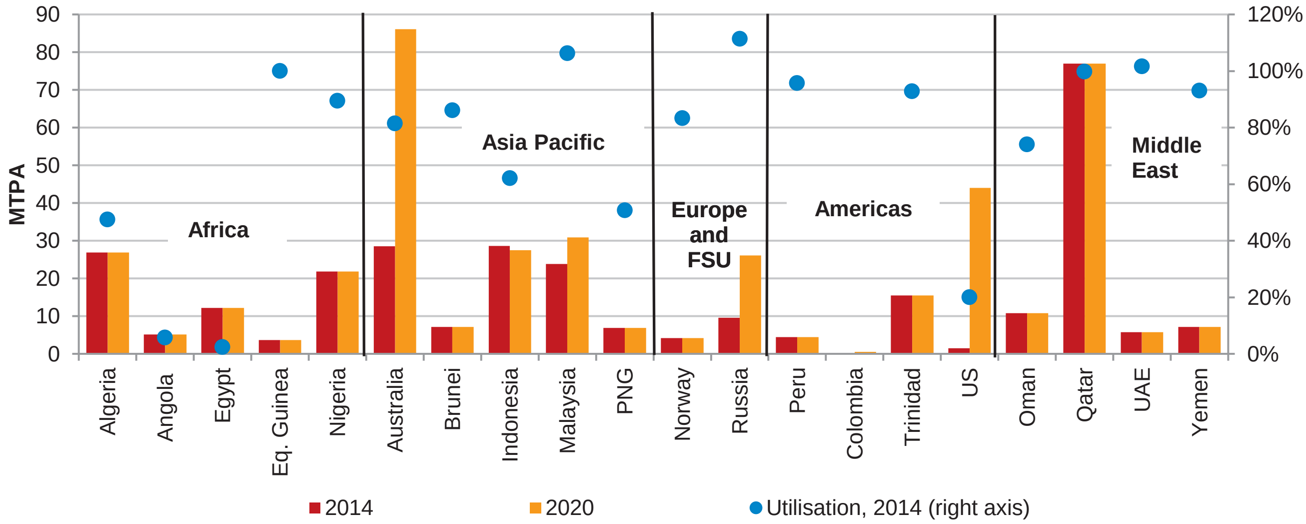


Figure 4.4: Liquefaction Capacity by Country in 2014 and 2020

Note: Liquefaction capacity only takes into account existing and under construction projects expected online by 2020.

Sources: IHS, IGU, Company Announcements

In Russia, Yamal LNG has been under construction since late 2013. The first train is announced to come online in 2017, with full completion scheduled for 2019. The project is challenged by the difficult Artic environment, as well as possible financing issues related to sanctions against Russia. However, once completed, it will bring Russia's total liquefaction capacity to 26.1 MTPA.

Proposed

The amount of proposed liquefaction capacity has expanded dramatically in recent years and totalled 799 MTPA as of early 2015. Much of the capacity is proposed in North America, where more than 50 liquefaction projects have been announced. Proposed capacity in the US stood at 269.6 MTPA as of the first quarter of 2015, mostly located in the Gulf of Mexico. Proposed capacity in Canada reached 345 MTPA, including nearly 160 MTPA proposed in 2014 alone. Most projects are planned for British Columbia on the country's west coast, but several projects have also been proposed in eastern Canada.

Despite aggressive development timelines put forward by project sponsors, only a handful of these projects have achieved meaningful commercial momentum. As a result, the actual capacity build-out in North America is expected to be far lower than what is proposed.

The discovery of large gas reserves offshore East Africa has resulted in multiple liquefaction proposals in Mozambique (27.5 MTPA) and Tanzania (20 MTPA). Both countries have project risks such as evolving domestic demand requirements, a lack of infrastructure and uncertainty over the regulatory process. As a result of these obstacles, East African projects are not expected online before the end of the decade.

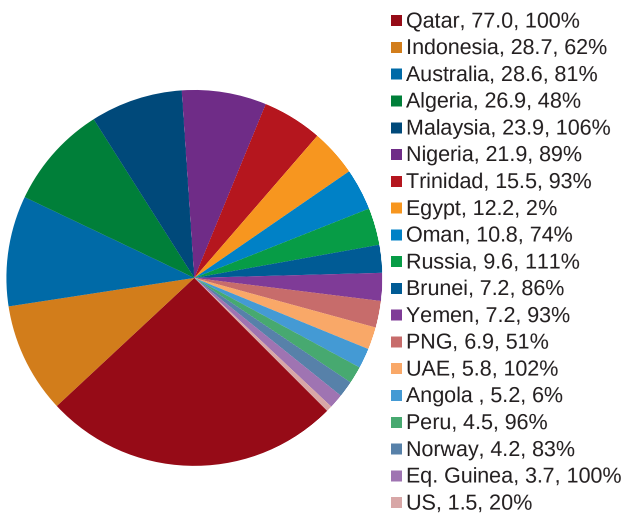


Figure 4.5: Liquefaction Capacity and Utilisation by Country, 2014

Sources: IHS, IGU

The Arctic is another potential source of new supply, with projects proposed in Alaska and Russia. Due to the difficult operating environment, cost estimates are very high and construction timelines are lengthy. The 20 MTPA project in Alaska is estimated to cost $45-65 billion and requires the construction of a complex 800-mile pipeline. Partners are targeting a start date in the mid-2020s. In Russia, a brownfield expansion train at Sakhalin-2 is announced to come online in 2018 but has not yet been sanctioned. Additional projects in the Russian sub-Arctic are targeting post-2020 start dates.

Region	2008	2014	2020 (Anticipated)	% Growth 2008-2014 (Actual)	% Growth 2014-2020 (Anticipated)
Africa	58.7	69.9	69.9	19%	0%
Asia Pacific	81.2	95.3	158.1	17%	66%
Europe	3.4	4.2	4.2	24%	0%
FSU	0.0	9.6	26.1	0%	172%
Latin America	15.5	20.0	20.5	29%	3%
North America	1.5	1.5	44.1	0%	2840%
Middle East	46.8	100.8	100.8	115%	0%
Total Capacity	**207.1**	**301.2**	**423.7**	**45%**	**41%**

Table 4.1: Liquefaction Capacity by Region in 2008, 2014 and 2020

Note: Liquefaction capacity only refers to existing and under construction projects.

Sources: IHS, Company Announcements

Finally, in Asia Pacific, 93.3 MTPA of capacity has been proposed, based primarily on offshore reserves. Many projects are predicated on floating liquefaction (FLNG). Given the high costs associated with the projects under construction in the region, especially in Australia, most of these proposals are being planned as post-2020 opportunities. Further, for much of the capacity (55.7 MTPA), project sponsors have not announced a start date.

Decommissioned

Only a small number of liquefaction plants are set to be decommissioned in the coming years. The final two trains at Arun LNG in Indonesia were taken offline in late 2014. The liquefaction project, which began operations in 1978, is now fully decommissioned and transitioned to an import terminal in early 2015.

While Kenai LNG in the US is also set be decommissioned in 2016, a few trains at the Arzew/Skikda complex in Algeria may further be decommissioned in the next few years. In the past two years, two new trains (totalling 9.2 MTPA) have been brought online in Algeria and are likely to replace older trains – some of which have been in operation since the 1970s.

Finally, output from Egypt has declined considerably since 2012. Damietta LNG has been taken offline and though it has not been officially decommissioned, exports are unlikely to be restarted due to rising domestic demand and limited feedstock. Operations at ELNG have also largely been suspended since early 2014, with the plant producing only a few cargoes throughout the year. It is not clear if these plants will eventually be decommissioned as the project partners are now considering importing gas from Israel and/or Cyprus to revive LNG exports.

4.4. LIQUEFACTION CAPACITY BY REGION

The Middle East accounts for the largest share of global liquefaction capacity totalling 34% in 2014. Capacity in the region is overwhelmingly located in Qatar, which alone comprises 26% of global capacity. However, after experiencing considerable growth over the past decade (again driven by Qatar), the region is unlikely to experience significant growth over the next ten years. No trains were under construction as of the first quarter of 2015. While liquefaction projects in Israel are now delayed due to regulatory constraints and Woodside Petroleum's 2014 decision not to invest in the Leviathan field, Cypriot LNG proposals remain at a conceptual stage. No other projects have been proposed in the region. Indeed, with the longer-term likelihood of trains being decommissioned in Oman and the UAE, the region's liquefaction capacity may actually decline going forward.

In 2014, Asia Pacific accounted for 32% of global capacity (95.3 MTPA). With 71.3 MTPA of capacity under construction, this share will increase rapidly over the next several years. 54% of total global capacity under construction is located in Asia Pacific. As a result, by 2020, liquefaction capacity in the region is set to surpass capacity the Middle East by a considerable margin (57 MTPA). Australia will be the primary driver of growth, but Malaysia and Indonesia will also contribute.

Beyond Asia Pacific, most of the capacity growth through 2020 will come from North America. In 2014, North America's share of global liquefaction capacity was less than 1%, with only one small export project – Kenai LNG in Alaska – online. However, the region's share will increase significantly over the next several years and is expected to reach 10% by 2020. Based on sanctioned projects, the growth in the region will come entirely from the US, where 44.1 MTPA is under construction. Many projects have also been proposed in Canada, as well as a few in Mexico, but these face many obstacles and are generally targeting post-2020 timelines.

While future capacity growth will be dominated by Asia Pacific and North America, sizeable growth is also expected in the Former Soviet Union (FSU). Russia is the only country in the region with existing liquefaction capacity via the 9.6 MTPA Sakhalin 2 plant; all future

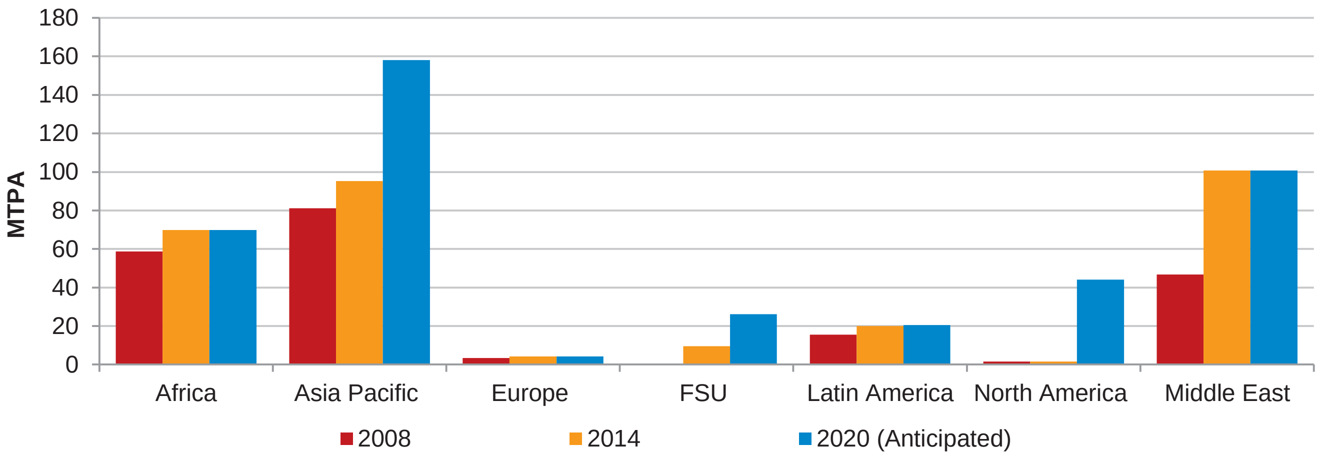


Figure 4.6: Liquefaction Capacity by Region in 2008, 2014 and 2020

Note: Liquefaction capacity only refers to existing and under construction projects.

Sources: IHS, Company Announcements

capacity in the region would also come from Russia. With Yamal LNG under construction, the region's market share could increase by 2020, but will remain relatively minor overall at around 6%.

Liquefaction capacity in Africa has increased considerably over the past few years as a result of two new trains in Algeria (9.6 MTPA) and the completion of Angola LNG (5.2 MTPA) – though the latter was taken offline for repairs in early 2014 and exports are not expected to resume until late 2015 at the earliest. As a region, Africa is unlikely to experience much capacity growth in the next five years. A number of projects, totalling 47.5 MTPA, have been proposed in Mozambique and Tanzania, but will likely not come online before 2020.

Similarly, capacity in Latin America is not expected to increase significantly through 2020. Current capacity stems entirely from Trinidad and Peru. Besides the small 0.53 MTPA Caribbean FLNG project under construction offshore Colombia, no additional liquefaction capacity has been proposed in Latin America.

4.5. LIQUEFACTION PROCESSES

Project developers are able to select from an increasing number of liquefaction processes. In recent years, many new technologies have been developed, with several processes focusing on smaller liquefaction trains.

In 2014, 50% of existing liquefaction capacity utilised APC C3MR technology, with another 30% split between AP-X and APC Split MR. While the AP-X technology has exclusively been used in the Qatari mega-trains to date, several under construction projects have also selected the APC C3MR or Split MR technology. Cameron LNG, Yamal LNG and Donggi-Senoro LNG will utilise the APC C3MR process, while Cove Point, Freeport LNG, Gorgon LNG and Ichthys LNG will use the APC C3MR/Split MR process. Combined, these projects account for 68.6 MTPA of the 128.1 MTPA of capacity under construction as of the first quarter of 2015.

Given the large amount of capacity under construction, Air Products is expected to retain its leading position through 2020. However, its market share is set to fall to 73% as other new projects come online using competing technologies. The Optimized Cascade® technology will see particularly strong growth. Twelve trains (52.2 MTPA of capacity) were under construction using the technology as of the first quarter of 2015. The technology is well-suited to dry gas, and as a result has been the top choice for coal-bed methane (CBM) projects in Australia, as well as a few projects in the US that are connected to the existing pipeline grid and will receive dry gas. The market share of the Optimized Cascade technology is set to rise from 13% to 21% by 2020.

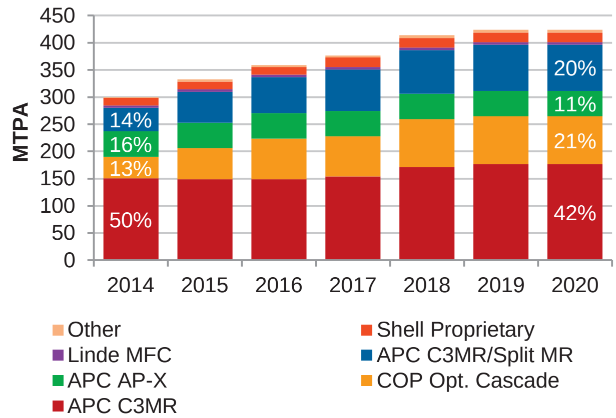


Figure 4.7: Liquefaction Capacity by Type of Technology, 2014-2020

Source: IHS

Other technologies make up only a small portion of existing and under construction capacity, but may see an increase in market share going forward. In North America, multiple projects (e.g. Elba Island, Woodfibre LNG, Calcasieu Pass) have been proposed based on small-scale modular liquefaction processes. The use of these technologies would allow developers to begin constructing liquefaction trains offsite, which may help to reduce costs.

4.6. FLOATING LIQUEFACTION (FLNG)

168.3 MTPA
Proposed FLNG capacity, Q1 2015

The 2015-2018 period will see the emergence of FLNG. Three projects totalling 6.8 MTPA were under construction as of the first quarter of 2015 and scheduled online before 2018. The technology, if proven economical and reliable, could have a transformative impact on the industry.

The largest floating project under construction is the 3.6 MTPA Prelude FLNG, which was the first to reach FID in 2011. Sanctioning of Prelude FLNG was shortly followed by FID on two smaller projects in 2012 – the 0.5 MTPA Caribbean FLNG in Colombia and the 1.2 MTPA PFLNG 1 in Malaysia. A second phase at PFLNG was sanctioned in early 2014. Caribbean FLNG was scheduled to start commercial operations in mid-2015, though in early 2015 project developers announced delays due to the low oil price environment. PFLNG 1 is scheduled to come online in 2016, with Prelude FLNG expected to begin operations in 2017.

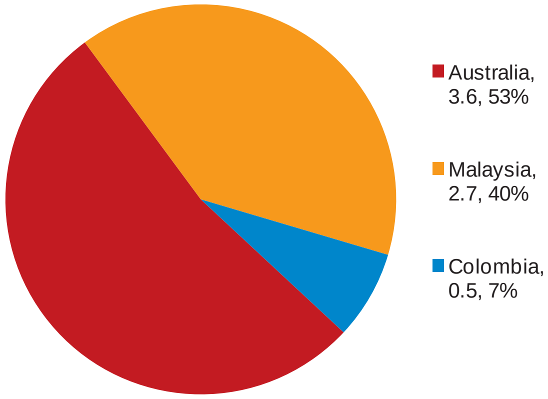


Figure 4.8: Under Construction FLNG Capacity by Country in MTPA and Share of Total, as of Q1 2015
Source: IHS

Beyond the projects under construction, more than 20 FLNG proposals have been announced. Companies see FLNG as a leading development option for offshore gas that may otherwise be stranded. Even for onshore resources, FLNG has been proposed as a means to avoid difficult onshore permitting processes, or to allow for cheaper offsite construction of the processing equipment. This is particularly true in Western Canada, where project developers are hoping to minimise costs by completing primary construction work in Asian shipyards before moving the vessel to North America. Total proposed FLNG capacity as of early 2015 was 168.3 MTPA, mostly in the US and Canada.

2012-2014 Liquefaction in Review

Capacity Additions

+19 MTPA

Growth of global liquefaction capacity

Global liquefaction capacity increased from 282 MTPA in 2012 to 301 MTPA in 2014

128.1 MTPA was under construction as of Q1 2015

700 MTPA of new liquefaction projects have been proposed since 2012, primarily in North America

New LNG Exporters

+2

Number of new LNG exporters

Angola (2013) and PNG (2014) joined the list of countries with LNG export capacity

A number of project proposals in emerging regions such as Canada and East Africa could lead to the emergence of several new exporters in the years ahead

US Build-out Begins

4

US projects sanctioned since 2012

Previously expected to be one of the largest LNG importers, 44.1 MTPA of export capacity was under construction in the US as of Q1 2015

Several additional US projects made regulatory and commercial progress. In total, 268 MTPA of capacity is proposed in the US

Floating Liquefaction

6.8 MTPA

FLNG capacity under construction

Since 2012, 146 MTPA of floating liquefaction capacity has been proposed. Four projects have been sanctioned, totaling 6.8 MTPA

Many proposals announced in the past few years aim to market gas from smaller, stranded offshore fields

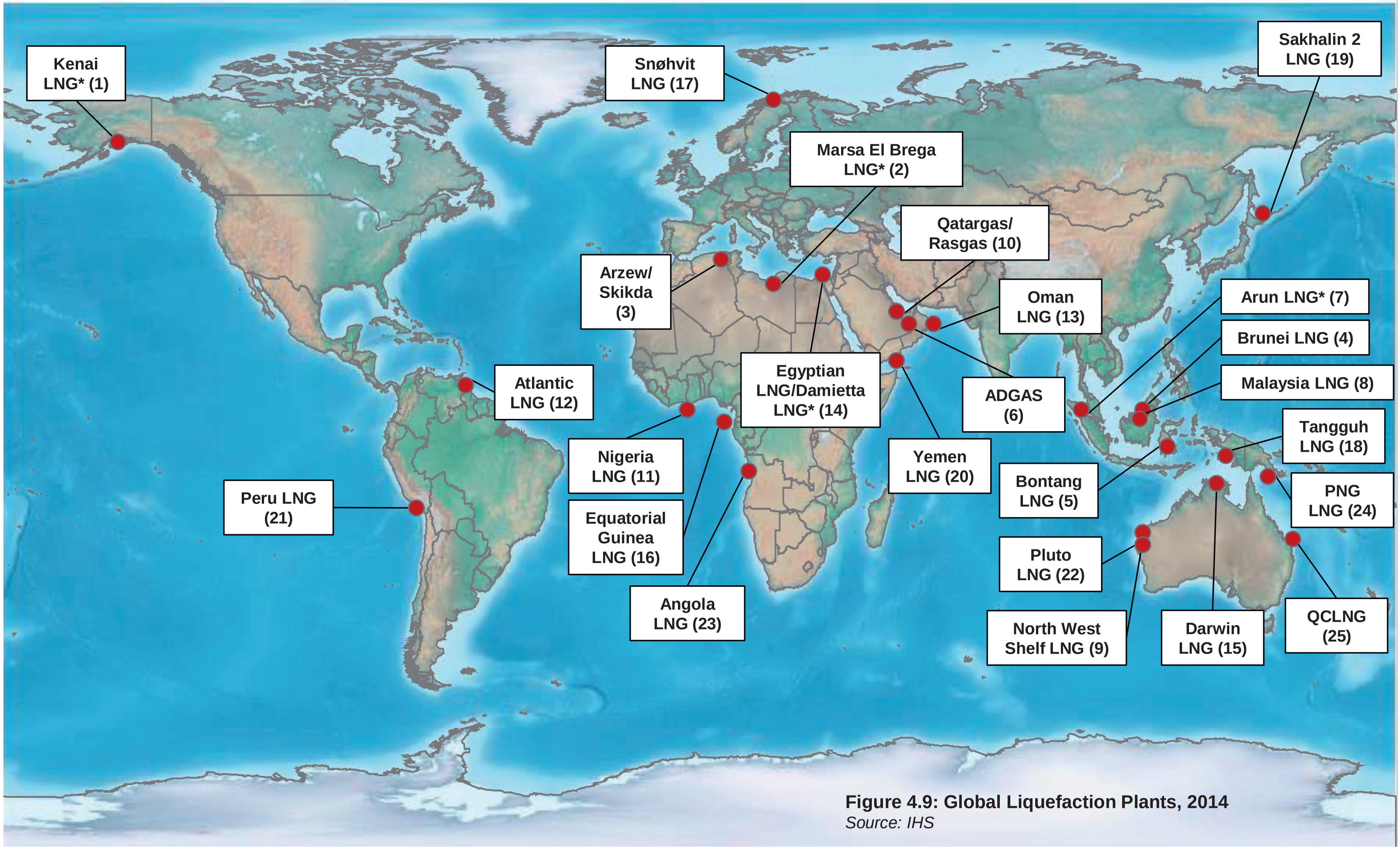


Figure 4.9: Global Liquefaction Plants, 2014

Source: IHS

Note: Further information on each of these plants can be found in Appendix I by referring to the reference numbers listed in parentheses above. The liquefaction projects are numbered in the order in which they were brought online.

** Damietta LNG in Egypt has not operated since the end of 2012; operations at Egyptian LNG have been greatly reduced since the start of 2014. The Marsa El Brega plant in Libya is included for reference although it has not been operational since 2011. Kenai LNG restarted operations in 2014, but is only permitted to operate until early 2016. Arun LNG was decommissioned in late 2014 – the facility was converted into a regasification terminal in early 2015.*

A number of floating projects are also associated with significant offshore reserves in Asia Pacific. The total proposed capacity is 25.8 MTPA, 21.3 MTPA of which is in Australia. Floating projects have also been proposed in Cameroon, Equatorial Guinea and Mozambique. Unlike in North America most of the proposals in Asia Pacific and Africa are planned as true floating vessels, positioned far offshore. Compared to permanently-moored vessels, this significantly raises project complexity.

Regardless of location, only a few of the proposed FLNG projects have made meaningful commercial progress. The technology encompasses a range of operational uncertainties, raising the question as to how quickly it will add sizeable volumes to the LNG market. Prospective project developers are closely monitoring progress of the under construction projects. This is particularly true for the large Prelude FLNG, the success of which will provide a clearer indication of how quickly and to what scale FLNG could progress. Given estimated construction timelines and other challenges, additional build-out of FLNG before 2020 is unlikely.

4.7. PROJECT CAPEX[4]

Cost has been the main challenge facing LNG projects worldwide. Liquefaction projects have faced considerable cost escalation since 2000 – several projects reported cost overruns in the range of 30-50% after construction began. Unit costs for liquefaction plants (in real 2014 dollars) increased from an average $321/tonne from 2000-2006 to $851/tonne from 2007-2014. Greenfield projects have increased from $326/tonne to $1,185/tonne, while brownfield projects have only increased to $516/tonne, up from $315/tonne.

LNG plant costs vary widely and depend on location, capacity and liquefaction process (including choice of compressor driver). The number of storage tanks is also a large determining factor, as is access to skilled labour and the cost of moving through regulatory requirements and permitting. Large amounts of steel, cement and other bulk materials are required. Finally, investment in gas processing varies depending on the composition of the upstream resource. Gas treatment includes acid gas, NGL and mercury removal, and dehydration. Figures 4.10 and 4.13 provide additional information on average liquefaction project costs by construction component and expense category.

Cost escalation has been pervasive in the Atlantic and Pacific Basins. Australia has been particularly exposed, with exchange rate fluctuations and shortages of skilled labour acting as key drivers of cost escalation.

Other project- and region-specific factors have played a role in cost overruns over the past several years. Higher input and labour costs have been common as a result of global competition for engineering, procurement and construction (EPC) contractors, as well as many projects beginning construction simultaneously.

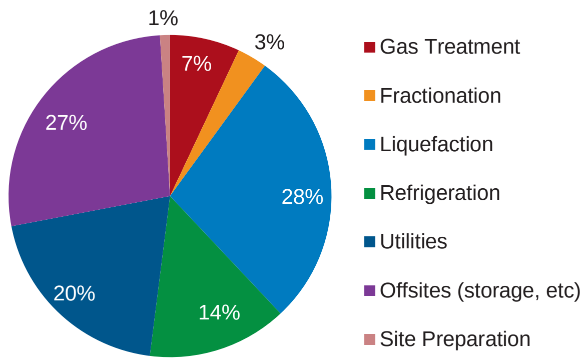


Figure 4.10: Average Cost Breakdown of Liquefaction Project by Construction Component

Source: Oxford Institute for Energy Studies

Further, several projects that were sanctioned or completed in the last few years have been located in difficult operating environments and are associated with complex upstream resources. This includes CBM resources in Eastern Australia, deepwater fields in Asia Pacific and Arctic environments in Norway and Russia. The complexity has also resulted in considerable delays, which further drive up costs.

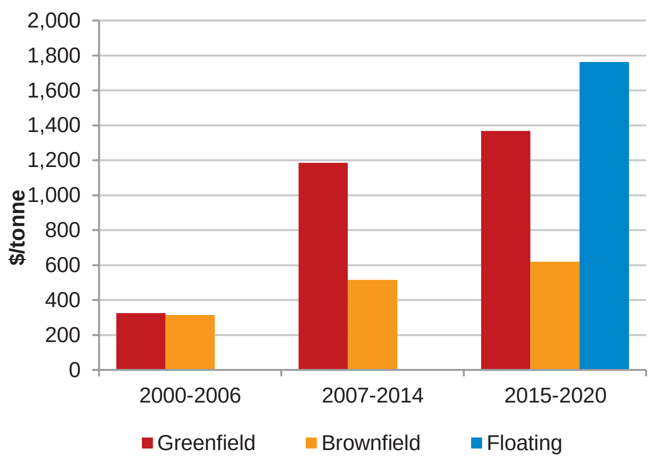


Figure 4.11: Average Liquefaction Unit Costs in $/tonne (real 2014) by Project Type, 2000-2020

Sources: IHS, Company Announcements

[4] *CAPEX figures reflect the complete cost of building the liquefaction facilities, including site preparation, gas processing, liquefaction, LNG storage and other related infrastructure costs. Upstream and financial costs are excluded.*

$1,325/tonne
Average expected cost for greenfield projects announced to come online between 2015 and 2020

The average unit cost for LNG projects in the Atlantic Basin reached $1,096/tonne from 2007-2014, compared to $324/tonne from 2000-2006. Projects in Asia Pacific fared only marginally better, with costs increasing from $330/tonne in 2000-2006 to $823/tonne from 2007-2014. Comparatively, Middle Eastern projects averaged $544/tonne from 2007-2014. The lower costs are largely due to the lesser cost of brownfield expansions in Qatar and Oman.

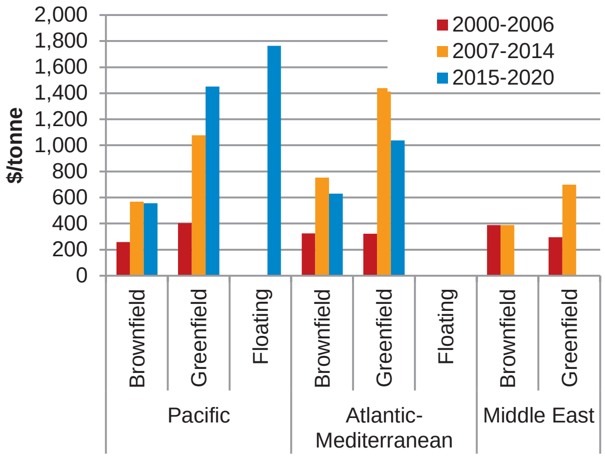


Figure 4.12: Average Liquefaction Unit Costs in $/tonne (real 2014) by Basin and Project Type, 2000-2020

Sources: IHS, Company Announcements

Based on announced costs, there will remain a considerable cost difference between greenfield and brownfield projects. Greenfield projects expected to come online from 2015-2020 have an average unit cost of $1,368/tonne.

Comparatively, brownfield developments offer much more favourable project economics. Notably, all four of the liquefaction projects under construction in the US are brownfield projects associated with existing regasification terminals. Unit costs for these brownfield projects average $619/tonne, well below the $1,368/tonne associated with under construction greenfield projects. However, these US projects also benefit from sourcing dry gas, which reduces costs by limiting the need for gas treatment infrastructure. Further, US projects may be less exposed to cost escalation because most of the EPC contracts associated with the projects were signed on a lump-sum turnkey arrangement (as opposed to the cost-plus contracts used for some global projects). Thus, the contractor is incentivised to keep the projects on time and on budget.

Because brownfield developments are predominately in North America, it is not clear if expansion projects in Australia, for example, would offer similar economics. Despite several trains being proposed in the country, these expansions no longer appear to be a priority for project developers and are viewed primarily as long-term options.

For the greenfield projects that do move forward, developers will need to secure attractive long-term sales arrangements to underpin project returns and financing. Low oil prices make this a more difficult undertaking. As a result, high costs are expected to be a major source of delay for future projects. Several proposed greenfield projects that have not yet been sanctioned have also announced very high project costs with economics that are challenged by low oil prices.

In Western Canada and Alaska, project economics are not only challenged by high greenfield liquefaction costs, but also by the need for lengthy (500 miles or more) pipelines. Projects have announced cost estimates of $35-40 billion for a fully integrated project, while in Alaska the estimate ranges from $45-65 billion. Large offshore projects in Asia Pacific – many of which are planned as FLNG projects – have made similar cost estimates.

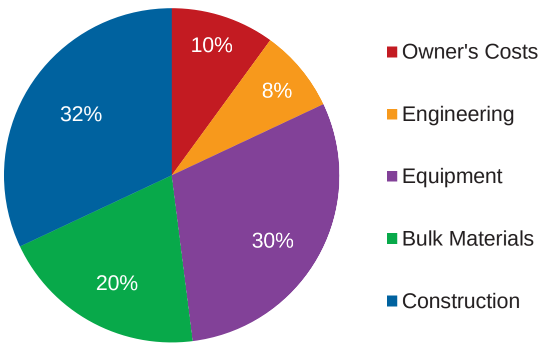


Figure 4.13: Average Cost Breakdown of Liquefaction Project by Expense Category

Source: Oxford Institute for Energy Studies

4.8. RISKS TO PROJECT DEVELOPMENT

The emergence of new areas with tremendous supply potential has been one of the most striking changes in the LNG industry over the past three years; the landscape of project development has evolved considerably.

However, many regions lost momentum in 2014, with timelines for several large projects being pushed back by several years. There are very few low-risk projects; in fact, several projects face such high-risks that they are likely to be delayed or even cancelled.

Liquefaction project risks include project economics, politics and geopolitics, environmental regulation, partner priorities and partners' ability to execute, business cycles, domestic gas needs and fuel competition, feedstock availability, and marketing and contracting challenges.

Project Economics

As noted in Section 4.7, high cost estimates have been a leading obstacle to project development. Adding to this is the risk associated with uncertain fiscal and regulatory regimes, especially in emerging liquefaction regions.

Politics, Geopolitics and Environmental Regulation

In the US, the timeline for regulatory approval is increasingly well-established, but is still complex and costly. Even for brownfield developments, environmental permitting is likely to take nearly two years or more.

In Western Canada, the British Columbia government has been persistent in its support for LNG development. Still, fiscal uncertainty has been an issue over the past few years, after the government announced it would develop an extra tax to be levied specifically on LNG export projects. Despite making the announcement in early 2012, the tax was not finalised until late 2014. Though the final tax was generally well received by project developers in the region, the delay in finalising it led to considerable uncertainty and made it difficult for projects to advance.

Similarly, in East Africa, both the Mozambican and Tanzanian governments support the development of liquefaction projects, but the fiscal structure under which the projects would operate has been a key source of uncertainty. While Mozambique published an LNG Decree Law in late 2014, providing the legal and contractual framework for LNG projects in the country to move forward, Tanzania is in the process of revising its national oil and gas policy. The latter was delayed and is unlikely to be finalised prior to national elections in late 2015.

Risk Factors	Impact on LNG Project Development
Project Economics	High project costs require developers to sign long-term sales contracts that will allow for a sufficient return. Cost overruns and changing market prices can have a large impact on when or if a project is sanctioned.
Politics & Geopolitics	Permitting may be time consuming. Federal or local governments may not be supportive of exports and could levy additional taxes on LNG projects or establish stringent local content requirements.
Environmental Regulation	Regulatory approval may be costly and extends to the approval of upstream development and pipeline construction. Local environmental opposition, including from indigenous groups, may also arise.
Partner Priorities	Not all partners are equally committed to a project and face different constraints depending on their respective portfolios. Ensuring alignment in advance of FID may be difficult.
Ability to Execute	Partners must have the technical, operational, financial and logistical capabilities to fully execute on a project. Certain complex projects may present additional technical hurdles that could impact project feasibility.
Business Cycle	Larger economic trends (i.e., declining oil prices, economics downturns) could limit project developers' ability or willingness to move forward on a project.
Feedstock Availability	The overall availability of gas to supply an LNG project may be limited by technical characteristics of the associated fields or the requirement of long-distance pipelines.
Fuel Competition	Interest in a project may wane if project developers or end-markets instead seek to develop or consume competing fuels, including coal, oil or renewables.
Domestic Gas Needs	Countries with high or rising gas demand may choose to use gas domestically rather than for exports. This often results in new or existing liquefaction projects being required to dedicate a share of production to meet domestic demand.
Marketing/Contracting	Project developers need to secure LNG buyers for a large portion of project capacity before sanctioning a project. Changing or uncertain market dynamics may make this more difficult.

Table 4.2: Liquefaction Project Development Risks
Source: IHS

Local opposition to the export of natural resources may also emerge as a serious obstacle in East Africa. Aware of the potential for governmental delay and lack of institutional capacity, project developers in the region have said they will move slowly and be patient before fully sanctioning projects. Persistent political volatility has also hampered development of additional liquefaction capacity in Nigeria, as well as several other countries.

Partner Priorities, Ability to Execute and Business Cycles

Even in well-established regions, project partners have often found it difficult to agree on development timelines due to differing priorities. This is particularly true for large scale projects requiring several billion dollars of investment. Not all partners are equally committed to a project. Smaller companies may be unable or unwilling to commit to investments on that scale, while larger players are frequently in the position of choosing between several large opportunities in their respective portfolios.

The number of projects proposed has increased considerably over the past several years, but many are being developed by project sponsors with no experience in liquefaction. This is particularly true in North America, where a large percentage of projects are affiliated with companies which have no LNG experience. Developers must have the technical, operational and logistical capabilities to execute a project.

Concerns over a company's ability to execute on any component of an LNG project will also make it more difficult for that company to secure sufficient project financing. In Israel, for example, Noble Energy has been unable to move forward with proposed liquefaction projects based on offshore reserves because it has been unable to secure a partner with sufficient LNG experience.

Even for experienced developers, their ability or willingness to sanction a liquefaction project may be impacted by overarching business cycles, including declining oil prices or economic downturns. During these times, the general investment climate may make investments very challenging.

Mooring of the Seri Balhaf before LNG Cargo Loading. Balhaf, Yemen.

Feedstock Availability, Domestic Gas Needs and Fuel Competition

In several countries, the desire to prioritise gas for local consumption is strong, meaning proposed export projects may not be permitted. This is often combined with declining feedstock production. In Egypt, rising domestic demand resulted in Damietta LNG being taken offline in late 2012. The country's second project, ELNG, saw production decline sharply in early 2014, exporting only a few cargoes throughout the year. Production from fields associated with these projects is set to decline over time, and producers have little incentive to invest in new fields given the lower gas prices offered in Egypt's domestic market.

While not as immediate as the situation in Egypt, Trinidad and Oman also face rising domestic demand that may combine with declining feedstock production to eventually result in lower LNG exports. Algeria may also be impacted. New or brownfield export proposals, including those in Indonesia, Malaysia and Mexico may further be hindered by the prioritisation of domestic demand over exports in these countries. Moreover, the competitiveness of LNG relative to alternate fuels – both in terms of project returns and downstream economics – remains a major factor that can affect liquefaction project investment decisions worldwide.

Marketing and Contracting

A major challenge to the development of future projects is the looming supply from Australia and the US set to come online over the next five years. With 128.1 MTPA under construction and announced to come online by 2020, many market players expect the LNG market to loosen considerably during this time, making it more difficult for project developers to secure committed buyers.

Some projects under construction (e.g. Yamal LNG) have not yet signed offtake contracts for full project capacity. The inability to secure buyers has also been a major impediment to the development of LNG projects in Western Canada.

In the US, most projects are being developed as tolling facilities, in which the market risk is shifted to the tolling customer. In reserving capacity, the tolling customer agrees to pay a flat liquefaction fee to the terminal owner for the life of the contract, regardless of whether it elects to actually offtake volumes.

4.9. STATUS OF AUSTRALIAN LIQUEFACTION

Seven projects, totalling 57.6 MTPA, are under construction in Australia. All are expected online before 2018, at which point the country will become the world's largest liquefaction capacity holder.

Nearly all Australian projects have faced considerable cost escalation. Offshore projects have been particularly expensive. Gorgon LNG – announced to come online in late 2015 – has seen its budget increase to $54 billion from $37 billion. Wheatstone LNG and Ichthys LNG have also exceeded initial cost estimates. However, as construction at these projects nears completion, additional cost increases are less likely.

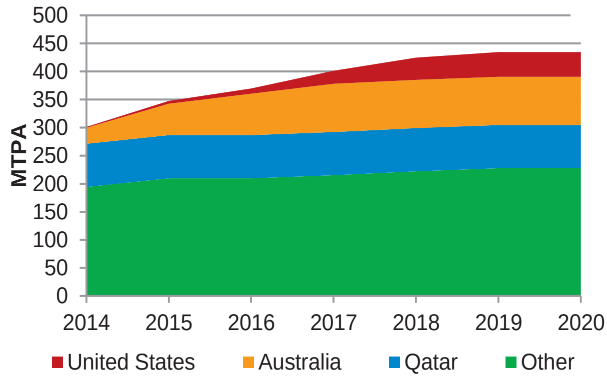


Figure 4.14: Post-FID Liquefaction Capacity Build-Out, 2014-2020

Note: This build-out only takes into account existing and under construction projects

Sources: IHS, Company Announcements

Three projects, totalling 25.3 MTPA, are based on CBM fields in eastern Australia. The first train at QCLNG came online in late 2014, with the second expected in mid-2015. Gladstone LNG (GLNG) and Australia Pacific LNG (APLNG) are also expected to begin operations in 2015. Each CBM-to-LNG project expects at least 1–2 years to reach full output, although it could take longer due to the challenges of ramping up feedstock gas from CBM fields. As the projects near completion and gas needs become more pressing, the developers have signed a number of gas supply and cooperation deals, hoping to improve LNG output for all three projects.

Several brownfield expansion trains have also been proposed in Australia. However, the country's high cost environment and the difficulties of CBM-to-LNG production have dampened prospects for expansion trains or additional projects in eastern Australia in the mid-term. At APLNG, a third and fourth train are considered only long-term options. Similarly, an additional three trains at Wheatstone LNG are no longer being actively pursued by project developers. More recently, in early 2015, Arrow LNG was cancelled and Cash Maple FLNG was stalled due to high costs and difficult market dynamics.

4.10. STATUS OF US LIQUEFACTION

There are four LNG projects under construction in the US Lower-48, totalling 44.1 MTPA. Exports are expected to begin in late 2015 and, by 2020, the US is anticipated to be the third largest liquefaction capacity holder after Australia and Qatar.

Interest in US LNG exports is driven by unconventional gas production, which has increased dramatically in the past several years. The majority of regasification terminals in the US are greatly underutilised and many terminal owners are hoping to improve on their investment by adding liquefaction capacity to the facilities. All four projects under construction are brownfield projects associated with existing regasification terminals.

Beyond the 44.1 MTPA under construction, an additional 269.6 MTPA of capacity has been proposed in the US (including Alaska). The vast majority of this capacity is located on the coast of the Gulf of Mexico, where 26 projects are proposed. Three projects have also been proposed on the East Coast, two on the West Coast and two in Alaska.

LNG export projects in the US must receive two major sets of regulatory approvals to move forward: export approval from the DOE and environmental approval from the Federal Energy Regulatory Commission (FERC). The approval process – particularly at FERC – is time consuming and costly; it remains a critical challenge for many proposed projects. However, several projects have now moved through the process and greater certainty has emerged regarding expected timelines and costs. Further, FERC has elected to focus only on direct project impacts and has not expanded the environmental analysis to include comprehensive indirect impacts (e.g. carbon emissions associated with increased domestic gas production for export).

Sabine Pass LNG was the first project to receive both approvals and began construction in April 2012. It was not until June 2014 that FERC approved a second project (Cameron LNG), followed by two additional projects in July (Freeport LNG) and September (Cove Point LNG).

Several other projects have submitted full applications to FERC. Corpus Christi LNG, Jordan Cove and Lake Charles LNG are scheduled to receive approval in 2015, with several more expected in 2016.

DOE approval has two phases. Approval to export to countries with which the US holds a free trade agreement (FTA) is issued automatically. For non-FTA approved countries, a permit will be issued only after the project receives full FERC approval. Previously, the DOE issued approval based on the order in which applications were received, but the agency changed its process in mid-2014. The new process is an attempt to devote greater attention to projects with the greatest commercial momentum.

The US government hopes to limit the impact LNG exports have on domestic gas prices, but it has not imposed any ceiling on the level of exports it will allow. 29 projects, totalling 323 MTPA (43.1 Bcf/d), have been granted FTA approval. 80.3 MTPA (10.7 Bcf/d) of liquefaction capacity has been granted approval to export to non-FTA nations. There have been a few legislative initiatives to further expedite the DOE approval process, but none have passed through the US Congress.

Beyond regulatory approval schedules, most US proposals face considerable commercial challenges. The demand for US LNG is partly tied to the perception of a major arbitrage potential due to the differential between low Henry Hub prices and high oil-linked LNG prices elsewhere. As lower oil prices reduce the price of traditional oil-linked LNG, US LNG linked to Henry Hub may become less attractive. This presents commercial risk for projects that have yet to make contracting progress. Contracts have been signed for nearly 99.5 MTPA of capacity or offtake from US terminals, but only 10.4 MTPA of contracts were signed in 2014 and early 2015. With lower oil prices and the forecasted loosening of the global LNG market in the mid-term, it may be difficult for additional projects to secure customers going forward.

For most announced US projects, construction is expected to take at least four years. Given the lengthy timelines associated with receiving full regulatory approval, finding LNG buyers and securing financing, the actual capacity build-out by the end of the decade will be far less than what has been announced. Beyond the four projects under construction, it is likely that only a few more advanced projects with committed buyers will come online in the US by 2020.

4.11. STATUS OF CANADIAN LIQUEFACTION

Projects in Western Canada face even steeper challenges that those in the US. Eighteen LNG export projects, totalling 293 MTPA of liquefaction capacity, were proposed on the coast of British Columbia as of early 2015 – more than double the capacity proposed at the beginning of 2014. Based on announced start dates, capacity in 2020 is set to reach 78 MTPA.

However, no projects have been sanctioned and only a few projects have achieved any meaningful commercial momentum. The region's prospects improved slightly in late 2014 when the British Columbia government finalised its LNG tax bill. Under the legislation, LNG projects would pay standard income taxes, plus an additional 1.5% until the project developer recoups development costs. Upon doing so, the additional tax will be increased to 3.5%. Finalising the tax bill was an important step for LNG development in Western Canada, but is unlikely to have a major impact on the overall pace of project development because several larger obstacles remain.

In particular, high estimated costs have emerged as a serious challenge to development of Western Canada LNG. Most advanced projects in the region require considerable upstream investment, lengthy pipelines over mountainous terrain and greenfield liquefaction plants in remote areas. As a result estimated projects costs are very high. With companies under pressure to reduce spending over the next few years, project developers will likely hesitate, in the near term, to commit capital to costly LNG projects.

Further, as in the US, the forecasted loosening of the global LNG market may make it difficult for LNG projects in Canada to secure buyers. To date, only a few binding offtake contracts have been signed. In light of these challenges, liquefaction capacity in Western Canada is unlikely to come online before the end of the decade. Yet given the size of the gas resource in the region, Western Canada remains a promising long-term opportunity.

Several LNG projects, totalling 51.5 MTPA of capacity, have also been proposed in Eastern Canada. Few have achieved significant commercial momentum, and the projects may find it difficult to secure LNG buyers in the near term. Given long shipping distances to Asia, most project sponsors appear to be targeting European importers.

Feedstock availability is a crucial uncertainty for projects in Eastern Canada. Most developers expect to procure gas from a mix of offshore production in Atlantic Canada, pipeline gas from the US (namely the Marcellus shale) and pipeline gas from producing regions in Western Canada.

Ras Laffan III Trains 6&7 Dehydration Units

Table 4.3: Proposed Liquefaction Projects in the US, as of Q1 2015

Project		Capacity	Status	Latest Company Announced Start Date	DOE/ FERC Approval	FTA/non FTA Approval	Operator
United States Lower 48							
Sabine Pass LNG*	T1-2	9	UC**	2015-16	DOE/FERC	FTA/ non-FTA	Cheniere Energy
	T3-4	9	UC**	2016-17	DOE/FERC	FTA/ non-FTA	
	T5	4.5	Pre-FID	2019	DOE	FTA	
	T6	4.5	Pre-FID	2019	DOE	FTA	
Freeport LNG*	T1-2	8.8	UC**	2018	DOE/FERC	FTA/ non-FTA	Freeport LNG Liquefaction
	T3	4.4	Pre-FID	2019	DOE/FERC	FTA/ non-FTA	
Cameron LNG*	T1-3	12	UC**	2018	DOE/FERC	FTA/ non-FTA	Sempra Energy
	T4-5	8	Pre-FID	N/A	N/A	N/A	
Cove Point LNG*		5.25	UC**	2017	DOE/FERC	FTA/ non-FTA	Dominion Resources
Elba Island LNG T1-2*		2.5	Pre-FID	2017	DOE	FTA	Kinder Morgan
Corpus Christi LNG T1-3		13.5	Pre-FID	2018-19	DOE/FERC	FTA	Cheniere Energy
Magnolia LNG T1-4		8	Pre-FID	2018-19	DOE	FTA	LNG Limited
Texas LNG T1-2		4	Pre-FID	2018	DOE	FTA	Texas LNG
Annova LNG T1-6		6	Pre-FID	2018	DOE	FTA	Exelon
Jordan Cove LNG T1-4		6	Pre-FID	2019	DOE	FTA/ non-FTA	Veresen
Oregon LNG T1-2		9	Pre-FID	2019	DOE	FTA/ non-FTA	Oregon LNG
Mississippi River LNG T1-4		2	Pre-FID	2019	DOE	FTA	Louisiana LNG
Lake Charles LNG T1-3*		15	Pre-FID	2019-20	DOE	FTA/ non-FTA	Trunkline LNG/BG
Golden Pass LNG T1-3*		15.6	Pre-FID	2019-20	DOE	FTA	Golden Pass Products
Gulf LNG T1-2*		10	Pre-FID	2019-20	DOE	FTA	Gulf LNG
Calcasieu Pass LNG T1-2		10	Pre-FID	2019-20	DOE	FTA	Venture Global Partners
South Texas FLNG T1-2		8	Pre-FID	2019-20	DOE	FTA	Next Decade International
Gasfin LNG		1.5	Pre-FID	2019	DOE	FTA	Gasfin Development
Downeast LNG		3	Pre-FID	2019	N/A	N/A	Downeast LNG
CE FLNG T1-2 (OS)		8	Pre-FID	2019	DOE	FTA	Cambridge Energy Holdings
Live Oak LNG		5	Pre-FID	2019	N/A	N/A	Parallax Energy
General American LNG T1-2		4	Pre-FID	2022	N/A	N/A	General American LNG
Main Pass Energy Hub FLNG T1-6		24	Pre-FID	N/A	DOE	FTA	Freeport-McMoran Energy
Barca FLNG 1-3		12	Pre-FID	N/A	DOE	FTA	Barca LNG
Gulf Coast LNG T1-4		21	Pre-FID	N/A	DOE	FTA	Gulf Coast LNG
Delfin FLNG 1-4		13	Pre-FID	N/A	DOE	FTA	Delfin FLNG
Eos FLNG 1-3		12	Pre-FID	N/A	DOE	FTA	Eos LNG
Monkey Island LNG T1-6		12	Pre-FID	N/A	DOE	FTA	SCT&E
Alturas LNG		1.5	Pre-FID	N/A	DOE	FTA	WesPac
Waller Point FLNG		1.3	Pre-FID	N/A	DOE	FTA	Waller Marine, Inc
Lavaca Bay FLNG		*8*	*Stalled*	*N/A*	*DOE*	*FTA*	*Excelerate Energy*

Sources: IHS and Company Announcements
** UC denotes "Under Construction"*

Table 4.4: Proposed Liquefaction Projects in Alaska, as of Q1 2015

Project	Capacity	Status	Latest Company Announced Start Date[1]	DOE/ FERC Approval	FTA/non FTA Approval	Operator
Alaska						
REI Alaska	1	Pre-FID	2020	N/A	N/A	Resources Energy Inc.
Alaska LNG T1-3	20	Pre-FID	2024-25	DOE	FTA	BP, ConocoPhillips, ExxonMobil

Table 4.5: Proposed Liquefaction Projects in Western Canada, as of Q1 2015

Project		Capacity	Status	Latest Company Announced Start Date	NEB Application Status	Operator
Western Canada						
LNG Canada	T1-2	12	Pre-FID	2021	Approved	Royal Dutch Shell
	T3-4	12	Pre-FID	N/A	Approved	
Kitimat LNG	T1	5	Pre-FID	2018	Approved	Chevron
	T2	5	Pre-FID	N/A		
Pacific Northwest LNG	T1-2	12	Pre-FID	2019	Approved	PETRONAS
	T3	6	Pre-FID	N/A	Approved	
WCC LNG	T1-3	15	Pre-FID	2024	Approved	ExxonMobil
	T4-6	15	Pre-FID	N/A	Approved	
Prince Rupert LNG T1-3	T1-2	14	Pre-FID	2023	Approved	BG Group
	T3	7	Pre-FID	N/A	Approved	
Woodfibre LNG		2.1	Pre-FID	2017	Approved	Pacific Oil and Gas
Douglas Channel FLNG		0.55	Pre-FID	2018	Approved	AltaGas
Kitsault FLNG 1-2		8	Pre-FID	2018-19	Filed	Kitsault Enery
Orca FLNG	T1	4	Pre-FID	2019	Filed	Orca LNG
	T2-6	20	Pre-FID	N/A	Filed	
Steelhead LNG T1-5		30	Pre-FID	2019-20	Filed	Steelhead Group
Aurora LNG T1-4	T1-2	12	Pre-FID	2023	Approved	Nexen (CNOOC)
	T1-4	12	Pre-FID	2028	Approved	
Stewart Energy LNG	T1	5	Pre-FID	2017	Not Filed	Stewart Energy Group
	T2-6	25	Pre-FID	N/A	Not Filed	
Discovery LNG T1-4		20	Pre-FID	2021-24	Filed	Quicksilver Resources
Grassy Point LNG T1-4		20	Pre-FID	2021	Approved	Woodside
Cedar FLNG 1-3		14.4	Pre-FID	N/A	Filed	Haisla First Nation
Tilbury LNG		3	Pre-FID	N/A	Filed	WesPac LNG
New Times Energy LNG		12	Pre-FID	2019	Not Filed	New Times Energy LNG
Triton FLNG		2	Pre-FID	N/A	Approved	AltaGas

Sources: IHS, Company Announcements

Table 4.6: Proposed Liquefaction Projects in Eastern Canada, as of Q1 2015

Project	Capacity	Status	Latest Company Announced Start Date	NEB Application Status	Operator
Eastern Canada					
Goldboro LNG T1-2	10	Pre-FID	2019-20	Filed	Pierdae Energy
Bear Head LNG T1-6	12	Pre-FID	2019-24	Filed	LNG Limited
Canaport LNG	5	Pre-FID	N/A	Not filed	Repsol
H-Energy LNG T1-3	13.5	Pre-FID	2020	Not Filed	H-Energy
Saguenay LNG T1-2	11	Pre-FID	2020	Filed	GNL Quebec

Table 4.7: Proposed and Under Construction Liquefaction Projects in Australia, as of Q1 2015

Project		Status	Capacity	Latest Company Announced Start Date	Operator
CBM-LNG Australia					
Australia Pacific LNG	T1-2	UC*	9	2015	ConocoPhillips
	T3-4	Pre-FID	9	N/A	
GLNG T1-2		UC*	7.8	2015-16	Santos
QCLNG	T1-2	UC*	8.5	2015	BG Group
	T3	Pre-FID	4.25	*Stalled*	
Other Australia					
Gorgon LNG	T1-3	UC*	15.6	2015-16	Chevron
	T4	Pre-FID	5.2	N/A	
Wheatstone LNG	T1-2	UC*	8.9	2016-17	Chevron
	T3-5	Pre-FID	13.35	N/A	
Ichthys LNG T1-2		UC*	8.4	2016-17	INPEX
Prelude FLNG		UC*	3.6	2017	Royal Dutch Shell
Abbot Point LNG T1-4		Pre-FID	2	2020	Energy World Corporation
Browse FLNG 1-3		Pre-FID	10.8	2021	Woodside Petroleum
Crux FLNG		Pre-FID	2	N/A	Royal Dutch Shell
Darwin T2		Pre-FID	3.6	N/A	ConocoPhillips
Fisherman's Landing		Pre-FID	3.8	N/A	LNG Limited
Scarborough FLNG		Pre-FID	6.5	2021	ExxonMobil
Sunrise FLNG		Pre-FID	4	N/A	Royal Dutch Shell
Timor Sea FLNG		Pre-FID	2.5	N/A	ConocoPhillips
Timor Sea LNG		Pre-FID	3	N/A	MEO
Cash Maple FLNG		*Stalled*	*2*	*N/A*	*PTT*
Pluto LNG T2-3		*Stalled*	*8.6*	*N/A*	*Woodside Petroleum*

Sources: IHS, Company Announcements

Looking Ahead:

How will lower oil prices impact FIDs on LNG proposals? *In the near-term, project developers will likely hesitate to commit to capital-intensive liquefaction projects. CAPEX budgets are under pressure and financing may become more of a challenge if oil prices remain low. Further, the prospect of inadequate returns on oil-linked LNG sales will give developers pause until greater certainty is established over long-term price expectations. Thus, the high level of sanctioning activity over the past several years is not expected to continue into 2015, with only a few advanced LNG projects with strong economics moving forward. Smaller scale projects could prove slightly more resilient, especially in Canada and the US where oil-indexed pricing is no longer a pre-requisite.*

Will the slate of under construction projects in Australia experience additional cost escalations or delays? *With 57.6 MTPA of liquefaction capacity under construction, Australia will be far and away the largest source of capacity growth in the near term. All seven projects are now in advanced stages of construction, meaning the risk of additional cost increases is relatively low. Delays in ramp-up remain a possibility for the CBM-LNG projects in Queensland, where project developers will have to effectively manage continuous drilling and the variability in gas production associated with CBM resources. Still, the Australian projects appear well-positioned to be operating at full capacity by 2017.*

Will emerging regions, such as Western Canada or East Africa, regain momentum? *Several LNG projects have been proposed in Western Canada and East Africa. Both regions host prolific resources but made only moderate progress through 2014 as cost estimates increased and it became apparent that several projects in the US would move forward before any in these emerging plays. Going forward, project sponsors in Western Canada and East Africa will likely continue to prove up reserves, but with their budgets under pressure, they are unlikely to make any major commitments in 2015. However, projects which have buyers in the ownership structure may be able to move forward, especially if the partners have already invested significant capital in upstream development.*

Ras Laffan II Train 4 at Night

5. LNG Carriers

The LNG shipping market has evolved over the last decade, driven by growth in global liquefaction capacity and demand in the Pacific Basin. The order and delivery of LNG vessels is quite cyclical in nature and 2014 marked the start of the next oversupply in LNG shipping capacity. With growth in the trading of spot and short-term LNG cargoes, fluctuations in spot shipping charter rates have had an increasingly important impact on the pricing and flow of LNG.

Estimated average monthly spot charter rates fell as low as ~$40,000/day in the third quarter of 2014 as demand for Atlantic volumes in the Pacific Basin weakened. The continuous wave of newbuilds hitting the market in 2015 will further push the LNG shipping market deeper into a period of oversupply, putting more downward pressure on spot charter rates in the near term. Additionally, the spot charter market has evolved into a multiple tier market, with older steam vessels competing with more efficient newbuilds to find fixtures. However, with the deflation of oil prices in late 2014 and into 2015, the cost spread between the propulsion systems narrowed, improving the competitive advantage of the more fuel-efficient vessels. The capacity surplus will likely continue until at least 2017 when new Australian and US export projects increase LNG supply and thus demand for shipping tonnage.

5.1. OVERVIEW

373 Carriers
Active LNG vessels with a capacity above 30,000 cm, end-2014

The wave of ordered LNG newbuilds began to flood the shipping market in 2014, with 28 conventional carriers delivered by the end of the year. In total, the active global fleet comprised 373 vessels – excluding vessels equal to or less than 30,000 cm in capacity – for a combined capacity of 55 mmcm.

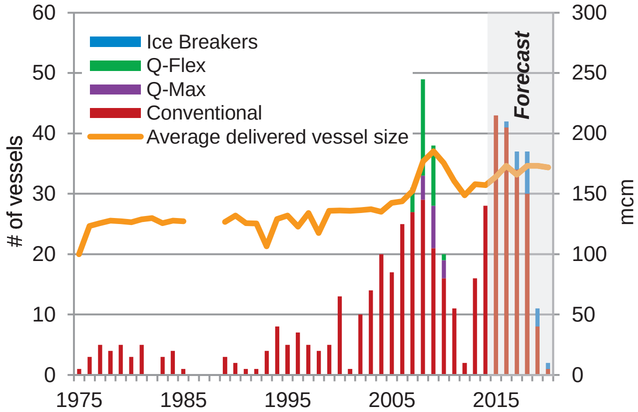


Figure 5.1: Global LNG Fleet by Year of Delivery versus Average Vessel Size

Source: IHS

Appetite for larger, more efficient LNG carriers in recent years has seen the average capacity of delivered newbuild vessels increase. In 2014, the average size of delivered vessels was 161,000 cm, an increase of 12,200 cm from 2012. Looking ahead, the average vessel capacity is set to be around 170,000 cm.

These larger conventional carriers have become the new standard for LNG vessel capacity in the orderbook. Out of the 68 vessels ordered in 2014, approximately 80% have a specified capacity between 170,000 and 174,000 cm. With the expansion of the Panama Canal in 2016, which will accommodate vessels of up to 180,000 cm, Post Panamax vessels (170,000-180,000 cm) will likely become the standard for newbuilds.

A new wave of newbuild ordering began in late 2012 and 2013. Unlike LNG demand factors that drove orders in past years, LNG supply factors led to the current cycle, with newbuild orders primarily tied to projects in Australia and the US. Potential delays in the start-up of these liquefaction plants could extend the current period of looseness in the shipping market, similar to the timing mismatch that occurred last decade.

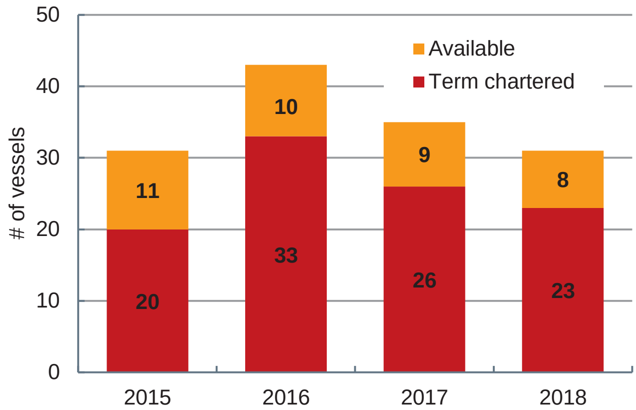


Figure 5.2: Estimated Future Conventional Vessel Deliveries, 2015-2018

Note: Available = currently open for charter

Source: IHS

The growing availability of LNG vessels continues to put pressure on spot market charter rates. Approximately 80% of vessels in the orderbook are associated with charters that extend beyond a year. Out of the speculative vessels, 11 are scheduled for delivery in 2015. With the majority of upcoming Australian LNG offtake already associated with charters for newbuild vessels in the orderbook, shipowners who are long on vessels are increasingly pinning their hopes on vessel retirements from the existing fleet. Moreover, the shipping needs of US LNG associated with LNG traders, international oil companies, or European utilities could provide some upside to a weaker market, though not until late 2015 at the earliest.

5.2. VESSEL CHARACTERISTICS

Propulsion Systems. LNG carriers have undergone a few major step changes in design since the first vessel came into service fifty years ago. Until the early 2000s, every LNG vessel was built with a reliable, yet not very efficient, steam turbine propulsion system, as boilers were the only means of consuming boil-off gas (BOG). However, in the last 15 years, LNG carriers have undergone major innovations and enhancements with regard to propulsion systems.

After almost forty years of the LNG fleet consisting entirely of steam turbine propulsion systems, GDF SUEZ ordered the first two LNG carriers – GDF SUEZ Global Energy and Provalys – to be powered by dual-fuel diesel-electric propulsion (DFDE) systems in 2001. DFDE systems are able to burn both diesel oil and BOG improving vessel efficiency by around 25-30% over the traditional steam-turbines.

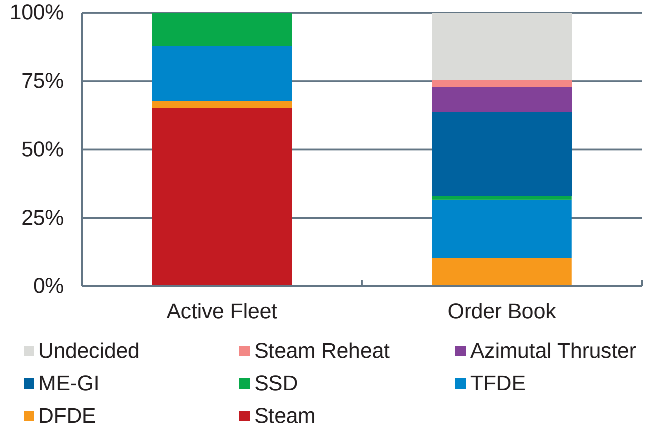
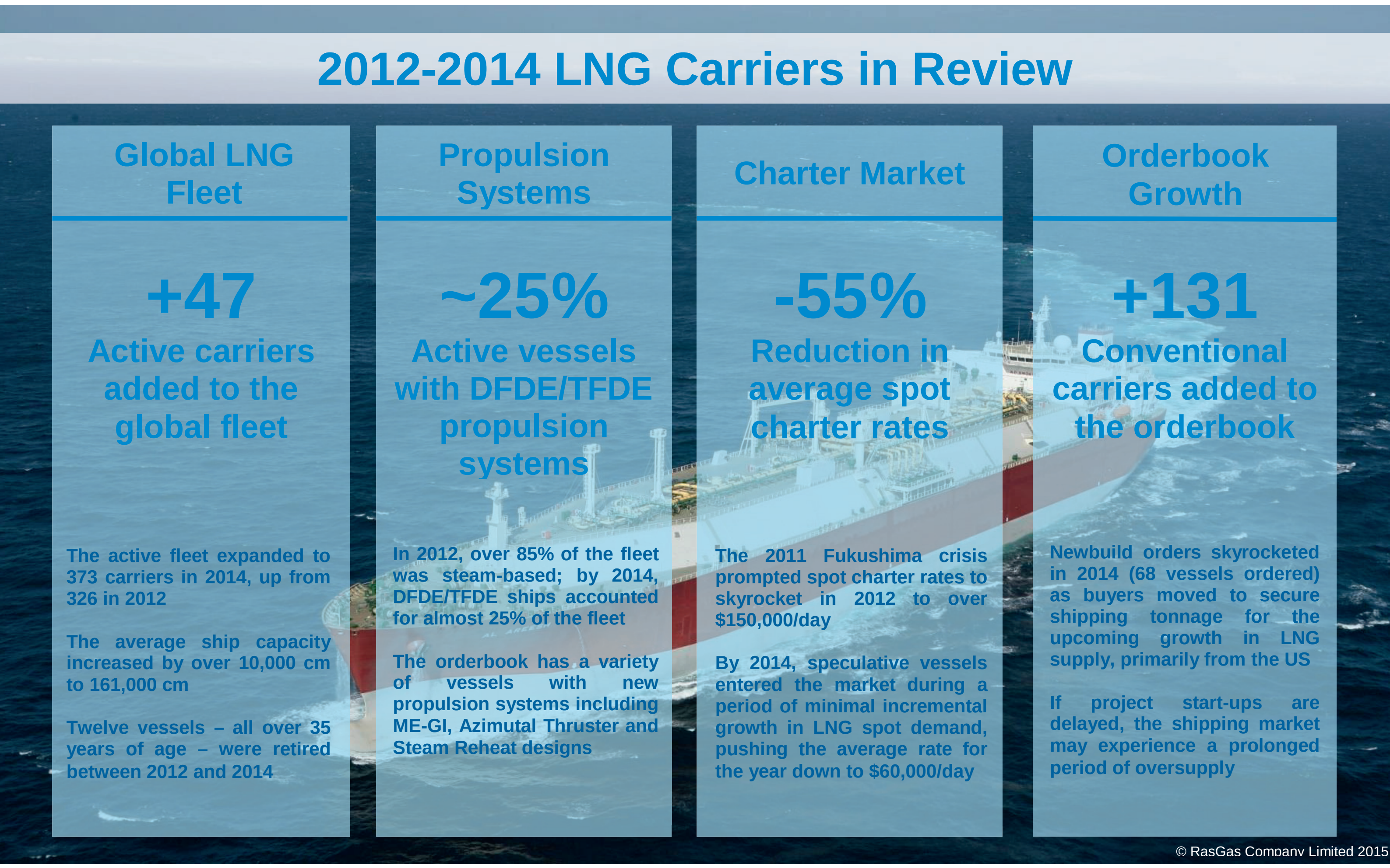


Figure 5.3: Existing and On Order LNG Fleet by Propulsion Type, end-2014

Source: IHS

Shortly after the adoption of DFDE systems, tri-fuel diesel-electric (TFDE) vessels – those able to burn heavy fuel oil, diesel oil and gas – offered a further improvement to operating flexibility with the ability to optimise efficiency at various speeds. While the existing LNG fleet is still dominated by the legacy steam propulsion system, almost 25% of active vessels are equipped with either DFDE or TFDE propulsion systems.



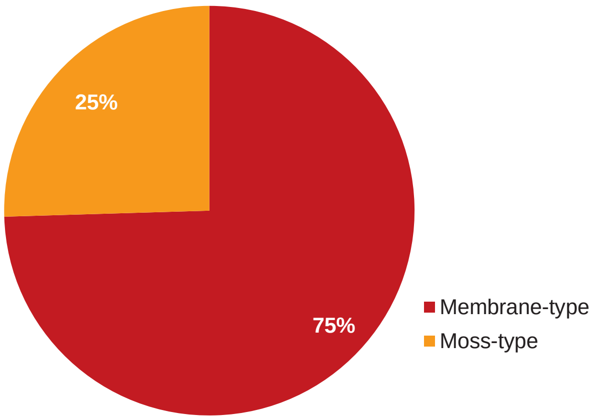


Figure 5.4: Existing Fleet by Containment Type, end-2014

Source: IHS

However, the orderbook looks quite different with over 40% of the vessels specified with a TFDE propulsion system. Moreover, around 30% of ordered vessels are designated to adopt the newest innovation in LNG carrier engine design: M-type, Electronically Controlled, Gas Injection (ME-GI) engines, which utilise high pressure slow-speed gas-injection engines. Unlike the Qatari Q-Class vessels equipped with slow speed diesel (SSD) propulsion systems – which utilise on-board reliquefaction units to handle BOG – ME-GI engines optimise the capability of slow speed engines by running directly off BOG (removing the need to reliquefy the gas) or utilising fuel oil. This flexibility allows for better economic optimisation at any point in time.

A 170,000 cm, ME-GI LNG carrier – operating at design speed and fully laden in gas mode – will consume around 15-20% less fuel than the same vessel with a TFDE propulsion system. While there is an improvement in fuel consumption, the reliability and extent of operational flexibility is still to be determined as no conventional-sized ME-GI vessel is in the existing fleet.

In order to improve the performance of a traditional steam-turbine propulsion system, the Steam Reheat engine design has been introduced, which ultimately reduces the boil-off rate (BOR) of the LNG on-board. The design is based on a reheat cycle, where the steam used in the turbine is re-heated to improve its efficiency. This improvement in the steam adaptation maintained the benefits of the simple steam-turbine while improving overall engine efficiency.

The Azimutal Thruster system – where the electric motor is mounted inside the propulsion unit and the propeller is connected directly to the motor shaft – has been adopted by the 15 Yamal LNG project-specific vessels. These powerful units (3 units of 15 MW each) allow the vessels to navigate the Arctic conditions along the Northern Sea Route (NSR) with greater hydrodynamic and mechanical efficiency.

Containment Systems. The containment system for a conventional LNG carrier is either Moss-type or Membrane-type. By the end of 2014, 75% of the active fleet had a Membrane-type containment system, which continues to lead the orderbook as the preferred containment option. To create value from the Moss-type vessels, ships considered for retirement are often converted to FSRUs. Additionally, companies are exploring the value of converting Moss-type steam designs – typically chartered at a discount relative to the more efficient Membrane-type – into FLNG units for smaller (0.5-1.5 MTPA) export projects.

A warranted average amount of 0.15% of the LNG cargo is expected to be consumed as BOG during transport. However, the rate of the BOG is ultimately determined by the insulation of the LNG carrier, which in turn varies according to the containment system – either Moss- or Membrane-type.

Vessel Size. LNG carriers range significantly in size, though more recent additions to the fleet demonstrate a bias toward vessels with larger capacities. Prior to the introduction of the Q-Class in 2008-2010, the standard capacity of the fleet was between 125,000 cm and 150,000 cm. As of end-2014, 58% of active LNG carriers had a capacity within this range, making it the most common vessel size in the fleet.

Propulsion Type	Boil-Off Rate (%)	Fuel Consumption (tonnes/day)	Average Vessel Capacity	Typical Age
Steam	0.15	175	<150,000	>10
DFDE/TFDE	0.11	130	150,000-180,000	<10
ME-GI	0.11	110	150,000-180,000*	Not Active
Steam Reheat	0.08	140	150,000-180,000	Not Active

Table 5.1: Propulsion Type and Associated Characteristics

** A Q-Class tanker is also undergoing propulsion conversion to ME-GI*

Source: IHS

Conversely, the Q-Flex (210,000-217,000 cm) and Q-Max (261,700-266,000 cm) LNG carriers that make up the Qatari Q-Class offer the largest available capacities. Due to the size of LNG exports from Qatar, the Q-Class (45 vessels in total) accounted for 12% of the active fleet at the end of 2014.

Vessels greater than 150,000 – yet still smaller than the Q-Class tankers – have been most prominent amongst the recent newbuilds entering the market. This is partly related to the upcoming expansion of the Panama Canal, which will accommodate vessels of up to 180,000 cm and redefine the Panamax vessel class. By the end of 2014, 27% of the active global fleet was in the 150,000 to 180,000 cm range. This share will grow rapidly in the years ahead with the average capacity in the orderbook standing at approximately 170,000 cm at the end of 2014.

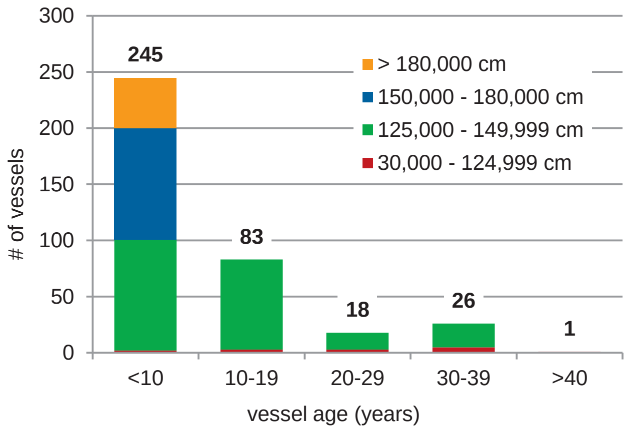


Figure 5.5: Active Global LNG Fleet by Capacity and Age, end-2014

Source: IHS

Vessel Age. At the end of 2014, 66% of the fleet was under 10 years of age, a reflection of the newbuild order boom that accompanied liquefaction capacity growth in the mid-2000s. Generally, safety and operating economics dictate if a shipowner considers retiring a vessel after it reaches the age of 30, although many vessels have operated for approximately 40 years.

As the recent wave of newbuilds continues to flood the market, vessel owners have been turning to conversion options to lengthen the operational ability of a vessel if it is no longer able to compete in the charter market. Around 7% of active LNG carriers were over 30 years of age in 2014; these carriers will likely be pushed out of the market as the younger, larger and more efficient vessels continue to be added to the existing fleet.

Typically, as a shipowner considers options for older vessels – either conversion or scrappage – the LNG carrier is laid-up. However, the vessel can re-enter the market. At the end of 2014, 12 vessels (all Moss-type steam tankers with a capacity of under 150,000 cm) were laid-up. Ten of these vessels were over 30 years old.

5.3. CHARTER MARKET

The LNG charter market in 2014 started off quite strong, propped up by firm LNG demand coming from Asia, Asia Pacific and Latin America. Spot LNG prices for delivery into these markets averaged $17.50/mmBtu in the first quarter of 2014, keeping traders and thus the LNG fleet occupied in the short-term. However, as speculative newbuilds entered the market, spot charter rates trended downward. There were momentary increases in spot charter rates as a result of inherent regional shipping imbalances, though it was not enough to stave off the overall decrease in spot charter rates caused by a fundamental oversupply of shipping capacity. Rate softening was accelerated by the shut-down of Angola LNG in early 2014, which released an additional seven vessels into the charter market as sublets.

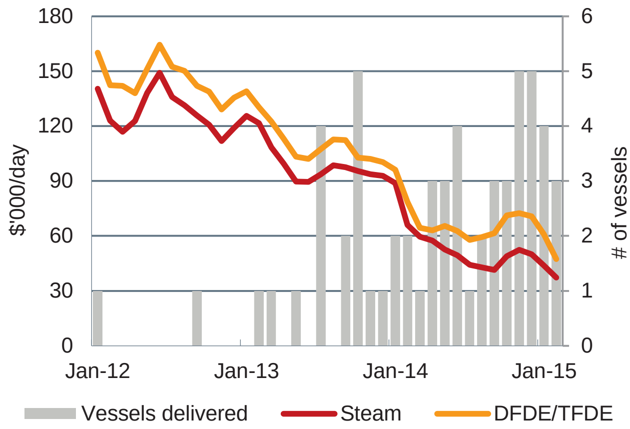


Figure 5.6: Average LNG Spot Charter Rates versus Vessel Deliveries, 2012 - February 2015

Source: IHS

A total of 28 conventional LNG tankers and 5 FSRUs (temporarily open for charter) were delivered from the yard in 2014, yet 18 tankers were laid-up or scrapped. However, only two liquefaction projects supported additional demand for shipping tonnage during the year – the PNG LNG and Arzew GL3Z plants. However, these projects required minimal tonnage from the spot charter market since the majority of vessels used to deliver the additional volumes were already ordered and chartered on a long-term basis.

With ample tonnage open for charter, spot rates for modern steam tankers steadily decreased throughout the year, dropping from $93,000/day to a low of $41,250/day in the third quarter. Similarly, the charter rates for the more fuel efficient DFDE/TFDE tankers, which began the year at around $100,000/day, dropped to a low of $57,750/day in the third quarter. Many shipowners who had hoped to secure premium rates for their newer and more fuel efficient tankers found it difficult to charter their respective carriers in a 'warm' state. Instead, the vessels were forced

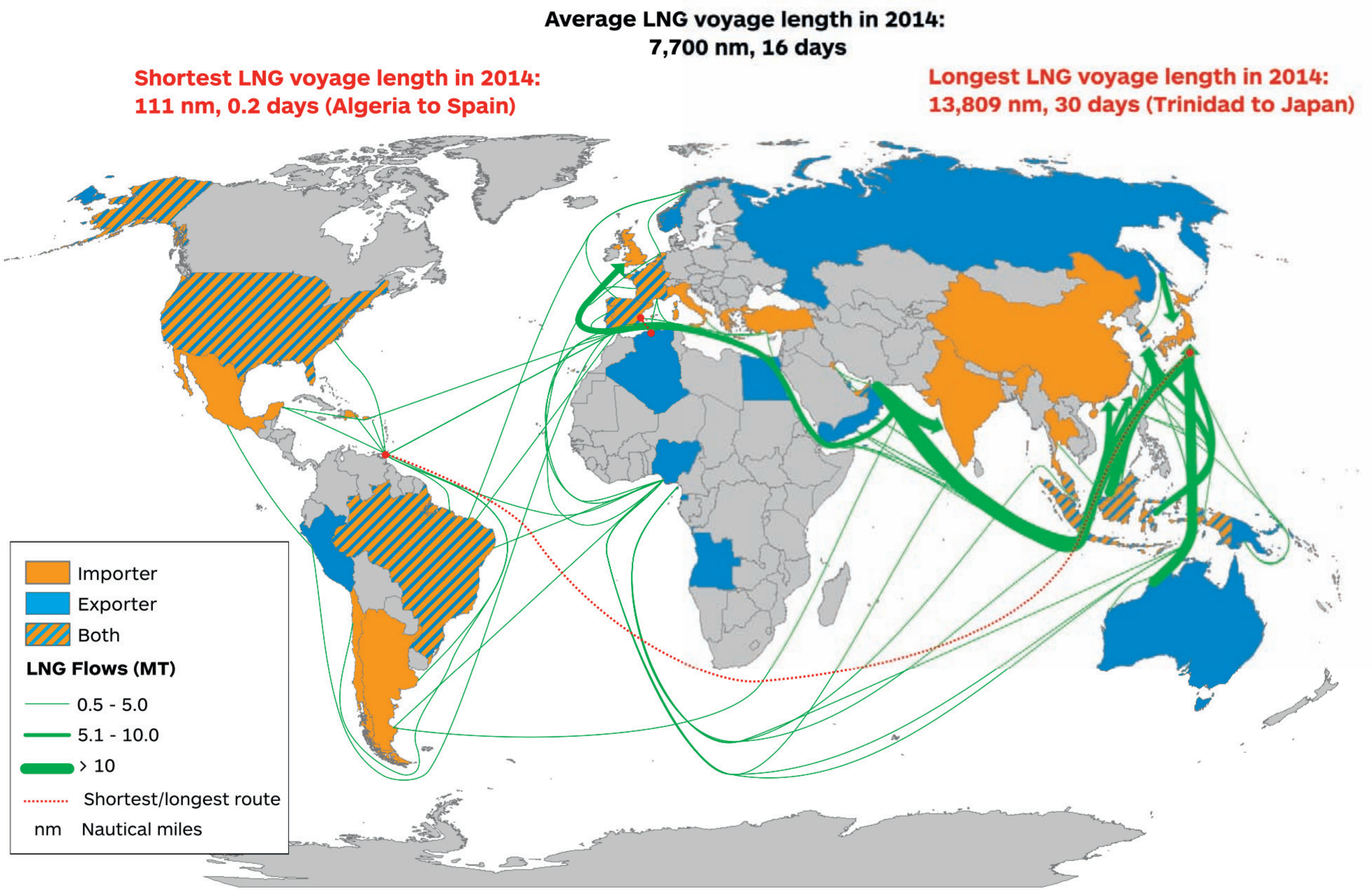


Figure 5.7: Major LNG Shipping Routes, 2014

Source: IHS

to load cool-down volumes and accept rates below the already weak market day-rate. The oversupplied carrier market provided traders additional flexibility to bid on short-term Free On Board (FOB) supply tenders. In contrast, during periods of shipping shortages, LNG suppliers typically require the buyer to nominate a tanker before being able to bid on an FOB cargo. With plenty of shipping tonnage available for short-term chartering, traders were able to bid on tenders without specified shipping capacity.

Speculative newbuilds expected to hit the market in the first half of 2015 will further push the LNG shipping market into oversupply. Early 2015 will see minimal growth in LNG production to absorb the new vessels. The capacity surplus is likely to continue until at least 2017 when Australian and US volumes ramp up, supporting additional demand for tonnage.

5.4. FLEET VOYAGES AND VESSEL UTILISATION

A total of 4,072 voyages were completed during 2014, a slight increase of 1.2% compared to 2013.

4,072 voyages
Number of LNG trade voyages in 2014

The rapid expansion in LNG trade over the past decade has been accompanied by an increasing diversification of trade routes. Trade was traditionally conducted on a regional basis along fixed routes serving long-term point-to-point contracts. However, the entry of new importers and exporters combined with growing destination flexibility in LNG supply contracts and greater spot market trade has prompted shipping routes to multiply.

Further, growing demand in the Pacific Basin has increased the average distance of LNG deliveries, with Atlantic Basin volumes being redirected East of Suez. In 2014, the longest voyage – from Trinidad to Japan around the Cape of Good Hope – was taken by three separate vessels. Conversely, the shortest voyage – a more traditional route from Algeria to the Cartagena terminal in Spain – occurred 14 times in 2014. The most common voyage was from Australia to Japan, with over 290 trips completed during the year.

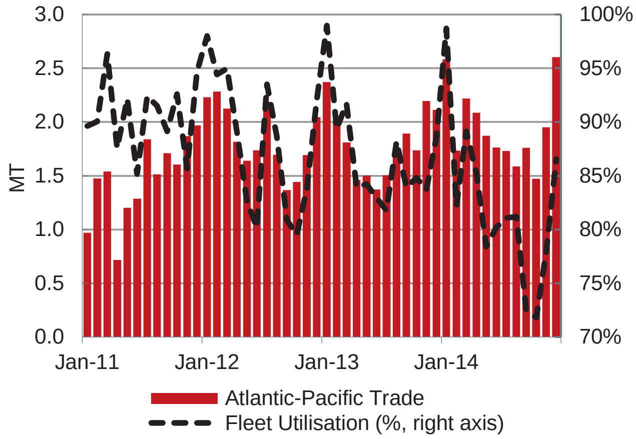


Figure 5.8: Atlantic-Pacific Trade versus Fleet Utilisation, 2011-2014

Note: Fleet utilisation was calculated comparing active shipping tonnage (excluding dry docked and/or laid-up vessels) and traded LNG volumes on a monthly basis.

Source: IHS

In 2014, the number of voyages completed on a per tanker basis dropped as many newbuilds sat idle in Asia Pacific and owners struggled to fix them beyond spot voyages. In contrast, vessel utilisation was at its highest in 2011 following Japan's Fukushima disaster, which required significant incremental LNG volumes sourced from the Atlantic Basin. This demand shock in the Pacific Basin strained the global LNG tanker fleet. Strong Atlantic to Pacific trade continued in the following three years as traders capitalised on the arbitrage opportunity between basins.

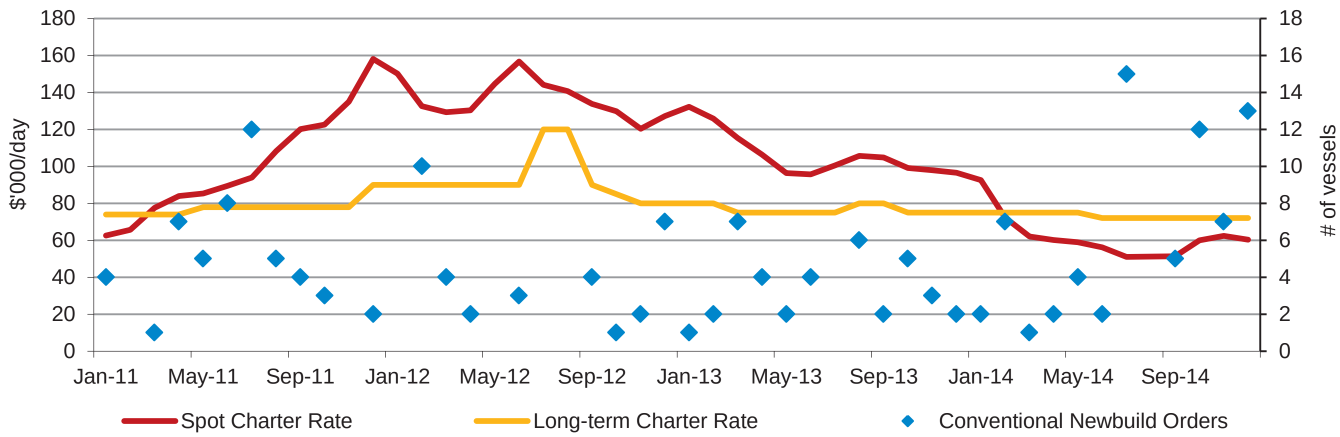


Figure 5.9: Estimated Long-term and Spot Charter Rates versus Newbuild Orders, end-2014

Source: IHS

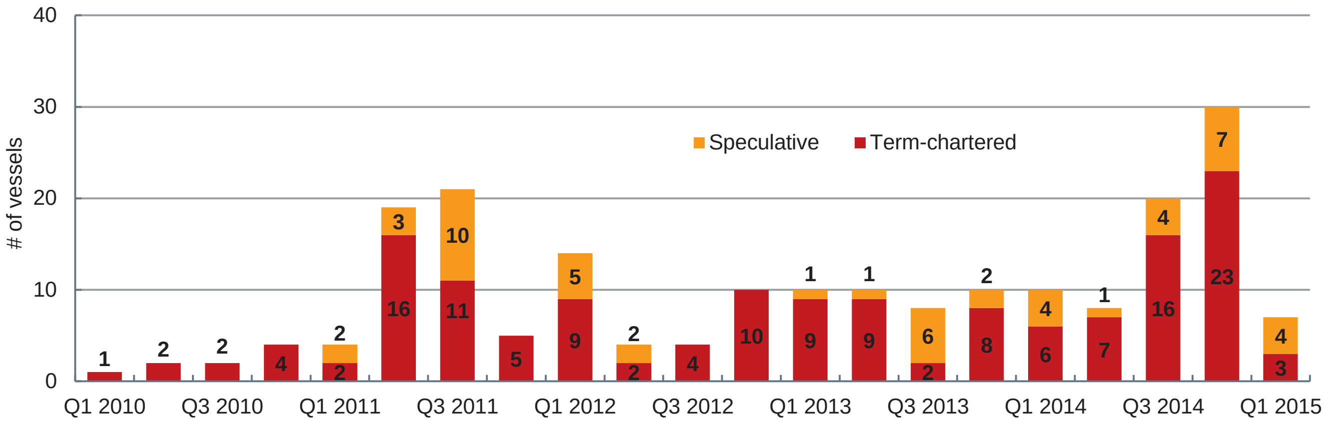


Figure 5.10: Firm Conventional Newbuild Orders by Quarter

Sources: IHS, Shipyard Reports

With the influx of unchartered LNG carriers in 2014, a number of shippers repositioned their available tankers in the Atlantic Basin in an attempt to charter them for a spot voyage to Asia Pacific. However, aside from December, the weakness in Northeast Asian spot purchasing in the second half of 2014 reduced demand for the long-haul cross-regional voyages, softening vessel utilisation rates.

5.5. FLEET AND NEWBUILD ORDERS

At the end of 2014, 155 conventional vessels were on order. Around 75% of vessels in the orderbook were associated with charters that extend beyond a year. By contrast, 31 vessels were covered by either a short-term charter (i.e. under one year) or open for employment.

In 2014, newbuild vessel orders increased two-fold compared to 2013. This upward swing in LNG carrier orders is chiefly linked to the upcoming US LNG build-out, though 15 Ice Classed Arc vessels were associated with the under construction Yamal LNG project in Russia. The majority of orders in 2014 are slated for delivery by early 2018. Out of the 68 vessels ordered in 2014, 85% will have a capacity greater than or equal to 170,000 cm. As these larger, more efficient newbuilds hit the water, some older vessels with less capacity will likely be retired.

Q-Flex Vessel Al Aamriya in Open Waters

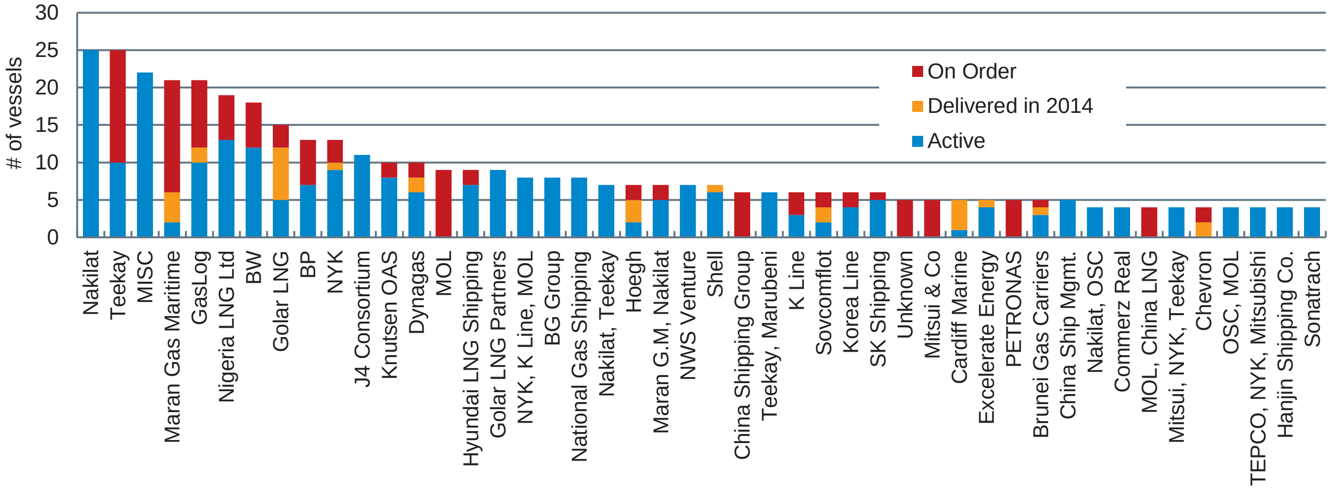


Figure 5.11: LNG Fleet by Respective Company Interests
Source: IHS

Many independent shipping companies made moves to dramatically grow their fleet sizes in the aftermath of the Fukushima nuclear crisis. While Golar ordered newbuilds primarily on a speculative basis, competitors such as Maran Gas Maritime and GasLog LNG chiefly placed orders based on term charter agreements with international oil companies.

In recent years, some international oil companies have chosen to move shipping off balance sheet to concentrate capital on their core business. BG has been the most notable example of this trend, renewing its fleet by chartering newbuild orders with independent shipping companies and selling off existing equity vessels to Gaslog in 2014. In contrast, BP has acted against the trend, ordering six fully-owned ME-GI newbuilds in December 2014.

5.6. VESSEL COSTS AND DELIVERY SCHEDULE

Over the past decade, LNG carrier costs have remained constant once controlled for capacity. However, the rapid growth in demand for newbuild TFDE vessels in 2014 pushed average TFDE vessel costs to rise from \$1,305/cm in 2005 to \$1,555/cm in 2014.

With the exception of the *Grace Dahlia* – which was delivered in September 2013, 68 months after the order was first placed – vessels have historically been delivered between 30 and 50 months after the order is placed. However, the delivery timeline has varied depending on the type of propulsion system. For instance, when DFDE vessels were first ordered in the early 2000s, the time to delivery was expanded as shipyards had to adapt to the new ship specifications. DFDE tankers delivered in 2006 saw an average time of 60 months between order and delivery.

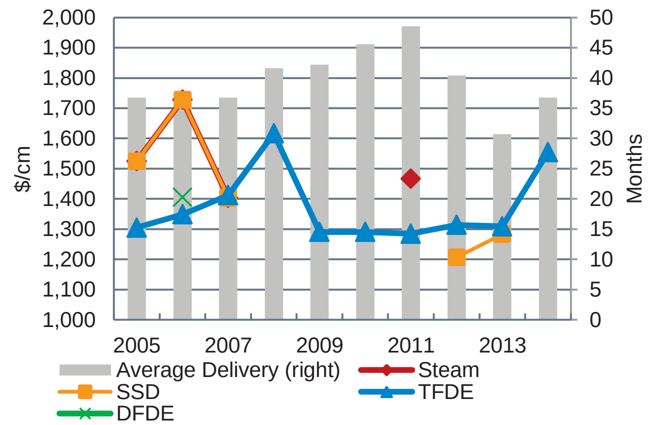


Figure 5.12: Average Delivery and Cost per Cubic Meter in Ordered Year by LNG Carrier Type, 2005-2014

Note: Stated rates for SSD and Steam vessels were equal between 2005 and 2007.

Source: IHS

5.7. NEAR-TERM SHIPPING DEVELOPMENTS

With the growing adaptation of ME-GI propulsion in newbuild vessels, shipowners may increasingly convert their previous orders to include the new propulsion system. The flexibility to burn gas or fuel oil depending on market conditions could offer ME-GI propulsion vessels a distinct competitive advantage in the market. In early 2015, Flex LNG notably opted to convert its DFDE propulsion for two newbuilds to ME-GI types. Additionally, one Q-Max vessel has been scheduled for a retrofit conversion to ME-GI propulsion in 2015 during a dry dock. If the retrofit proves economical and reliable during the pilot period, all the Q-Class could be converted to ME-GI.

In 2015, Suez Canal transit tolls for LNG carriers were increased, as the 35% discount was reduced to 25%. The previous discount rate had been in place since 1994. LNG carriers going through the Suez Canal pay tolls based upon gross tonnage, which causes the Moss-type to pay higher fees than the Membrane-type when comparing on the same cubic meter carrying capacity.

Suez Canal: LNG vessel toll structure (without discount)		
Suez Canal Net Tonnage (SCNT)	Laden	Ballast
First 5,000	7.88	6.70
Next 5,000	6.13	5.21
Next 10,000	5.30	4.51
Next 20,000	4.10	3.49
Next 30,000	3.80	3.23
Next 50,000	3.63	3.09
Remaining tonnage	3.53	3.00

Table 5.2: Tariff Structure for LNG Vessels Travelling via the Suez Canal

Note: A vessel is considered to be in a ballast voyage if it has LNG from its previous cargo equal to no more than 2% of the ship's Summer Deadweight (different from SCNT). Prices are reported in Special Drawing Rights (SDRs), not US Dollars (SDRs per currency unit are published by the International Monetary Fund). Tug fees must be added for an LNG vessel that does not provide a Gas Free Certificate.

Sources: IHS, Suez Canal

The expansion of the Panama Canal – which will allow around 90% of the existing LNG fleet to transit the canal – is set to commence operations in January 2016. Although the start-up will come a year behind the initial schedule, the 48-mile artery of the Panama Canal connecting the Atlantic and Pacific oceans will become the primary inter-basin route for US LNG exports. For shipowners from Gulf Coast LNG projects, the attractiveness of the canal is clear. The trip from the US Gulf Coast to Japan and back through Panama will take 43 days, shaving almost 20 days off the roundtrip voyage compared to going through the Suez Canal.

In January 2015, the Panama Canal Authority (PCA) officially released the proposed LNG vessel tariff structure. Unlike the Suez Canal, charges will be by volume and not tonnage. This different structure removes any transit pricing differential between Moss-type and Membrane-type vessels.

Based on those announcements, the fee charged to a laden 173,000 cm LNG vessel will equal $380,480. This is a very competitive tariff. Additionally, the PCA outlined its proposal to reward vessels that use the Panama Canal for round trips, by charging around $34,000 less than the standard ballast fee for a 173,000 cm vessel. Importantly, a vessel will be considered to be in ballast unless it has in excess of 10% of its cargo carrying capacity as heel.

Panama Canal: Proposed LNG vessel toll structure			
Bands in cm	Laden	Ballast	Ballast (roundtrip)
First 60,000	$ 2.50	$ 2.23	$ 2.00
Next 30,000	$ 2.15	$ 1.88	$ 1.75
Next 30,000	$ 2.07	$ 1.80	$ 1.60
Remaining Volume	$ 1.96	$ 1.71	$ 1.50

Table 5.3: Announced Tariff Structure for LNG Vessels Travelling via the Panama Canal

Note: A vessel is considered to be in ballast unless it has an excess of 10% of its cargo carrying capacity as heel. To be considered a roundtrip voyage, vessels must transit on ballast passage within 60 days of completion of the laden passage. There could be other additional costs not factored in like security, tugboats, and reservation fees.

Sources: IHS, Panama Canal Authority

In the US, the new law S. 2444, the Howard Coble Coast Guard and Maritime Transportation Act of 2014, was signed by the government in January 2015. The Act encourages the use of US-built, US-flagged and US-manned vessels for LNG exports from the US. While the act merely highlights the benefits for shipyards and employment opportunities within the US, it is unclear how the act will be implemented and enforced. By the end of 2015, the US Congress is slated to have outlined more concrete parameters in regards to the LNG-related issues in the Act.

Looking Ahead:

How quickly will a more pronounced three-tier market for LNG vessel charters emerge? *With the growing number of speculatively-ordered fuel-efficient TFDE and ME-GI tankers being delivered from the shipyards, a multi-tiered charter rate system could become more of a prominent fixture in the shipping market. In 2014, rates were quoted for 2nd generation steam and DFDE/TFDE tankers. However, as the global fleet becomes more diverse in propulsion systems and other key characteristics, rates may break out further to include 1st generation steam, ME-GI, and Steam Reheat carriers. The varying degrees of propulsion system efficiency in the global fleet – which provides potential charterers with more operational flexibility – will likely drive a more rigid segmentation of the LNG charter market over the coming years.*

When will the spot charter market recover? *Charter rates are expected to struggle over the next three years as more than 125 tankers are set to enter the market during this period. Many of the Australian projects are expected to come online during this period; however, the bulk of the volumes are contracted to Asian buyers, which results in a relatively short voyage distance. With more production and vessels positioned in the Pacific Basin, the number of LNG carriers required for the transport of the volumes is limited. During this period of weakness, older vessels will increasingly be retired, either through scrapping or conversion to floating regasification or liquefaction units. This may provide support for the charter rates to start recovering by 2017. However, with the oil price environment casting a negative light on sanctioning new LNG supply, the recovery in the shipping market may be pushed back until the beginning of next decade.*

Do non-traditional players in the LNG market have more opportunity to participate in supplying volumes*? With the increasing number of uncontracted volumes expected to come online over the next five years, there will likely be a larger role played by pure traders. Historically, the LNG trade had high barriers to entry, with all aspects tied to long-term contracts. Now, with the LNG carrier market saturated with speculatively ordered tonnage, a healthy supply of LNG and buyers looking for shorter contract durations, the environment is set for traders to capitalise on market conditions.*

Will the Arctic become the new frontier for LNG from year 2017 on, when Yamal LNG is scheduled to bring online its first liquefaction train? *Already two ice-classed LNG vessels have sailed along the Northern Sea Route (NSR) during the open water navigation window in years 2012 and 2013, assisted by Russian nuclear ice-breakers and benefitting from the shorter route from Europe to Asia. The fleet of 15 Arc7 ice-breaking LNG vessels dedicated to the project may be a breakthrough for maritime logistics and boost the traffic along the NSR. When the NSR is not navigable, the ice breakers will be used to shuttle cargoes from Yamal to Belgium for re-loading purposes.*

Ras Laffan Industrial City, LNG Vessels Loading

6. LNG Receiving Terminals

The global regasification market continues to expand at a steady pace, with capacity growth coming from new and existing importers alike. Particularly the advancement of floating regasification technology has enabled new countries to secure access to the global LNG market, while existing importers have often focused on bringing online larger terminals with increased send-out, berthing and storage capacity.

Global LNG receiving capacity increased to 724 MTPA as of end-2014 in a total of 30 import markets. Over the past five years alone, eight new countries have joined the ranks of existing importers, with an additional four countries expected to commission their first import terminal in 2015. With several new liquefaction plants ready to start operations in the coming years, import markets worldwide are expected to benefit from a looser supply environment and potentially lower prices, thus increasingly relying on LNG to meet their rising energy needs and replace competing fuels.

6.1. OVERVIEW

724 MTPA
Global LNG receiving capacity, end-2014

In 2014, global LNG receiving capacity increased by 31 MTPA (+4% YOY) to a total of 724 MTPA. Three of the world's largest importers in Asia led the capacity push, with Japan, South Korea and China all completing new large-scale import terminals. New terminals also came online in Brazil, Indonesia and Lithuania, while Chile, Kuwait, Singapore, and again Brazil finalised expansions at existing LNG import facilities. The total number of active regasification terminals as of end-2014 increased to 101. In the first quarter of 2015, Indonesia further completed the conversion of the Arun liquefaction plant into a 3 MTPA regasification terminal.

Just before the end of the year, Lithuania became the only new LNG importing country of 2014, bringing the total number of countries with LNG import capacity up to 30.[5]

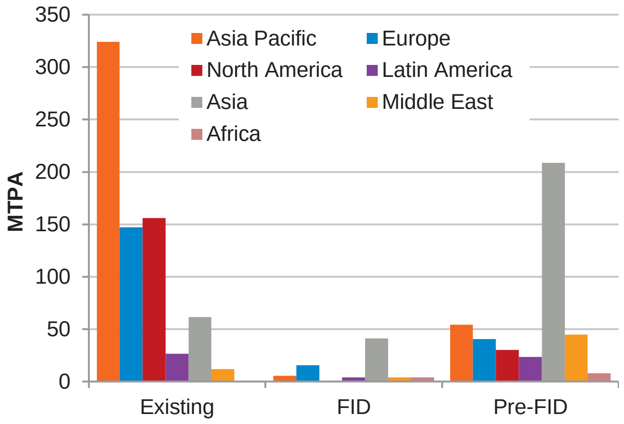


Figure 6.1: LNG Receiving Capacity by Status and Region, as of Q1 2015

Sources: IHS, Company Announcements

[5] *This count, along with all other totals within this section, only includes countries with large-scale LNG import capacity (1 MTPA and above). Refer to Chapter 12 for a description of the categorization of small-scale versus large-scale LNG.*

6.2. RECEIVING TERMINAL CAPACITY AND UTILISATION GLOBALLY

Since 2000, the number of LNG importing countries has tripled and regasification capacity has more than doubled. A wider range of LNG supply options, flexible shipping strategies, the growth of the spot market and floating regasification technology have allowed new countries to become LNG importers. This includes traditionally export-oriented regions (such as the Middle East), emerging economies with growing energy needs (in Asia, Asia Pacific and Latin America), and countries seeking greater energy security and diversification (mainly in Europe).

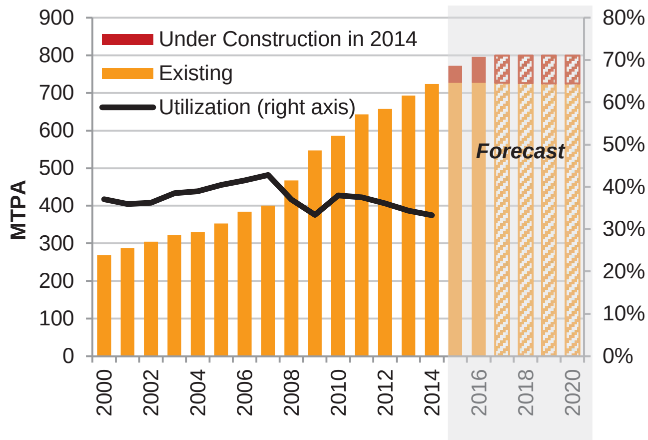


Figure 6.2: Global Receiving Terminal Capacity, 2000-2020

Note: The above forecast only includes projects sanctioned as of end-2014. As indicated by the diagonal bars, additional projects that have not yet been sanctioned could come online after 2016.

Sources: IHS, IGU, Company Announcements

7 terminals
Number of new receiving terminals brought online in 2014

In total, seven new regasification terminals were completed over the course of 2014. Four of these were added in the world's three largest LNG import markets: Japan (Hibiki), South Korea (Samcheok) and China (Hainan and Shandong). The remaining three – all floating regasification terminals – came online in Indonesia (Lampung), Brazil (Bahia/TRBA) and Lithuania (Klaipeda).

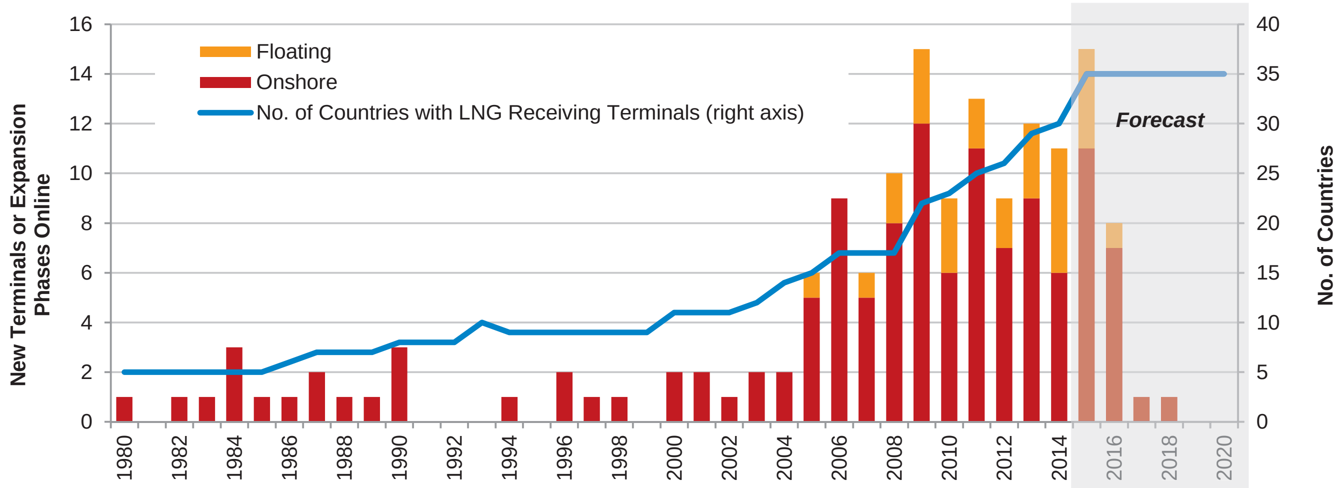


Figure 6.3: Start-Ups of LNG Receiving Terminals, 1980-2020

Sources: IHS, Company Announcements

Additionally, three capacity expansion projects were finalised in 2014. Singapore finalised the second phase of its Jurong Island terminal. In Kuwait (Mina Al-Ahmadi) and Brazil (Guanabara), two larger FSRUs replaced smaller vessels. Finally, the FSRU moored at Mejillones in Chile was replaced by a permanent onshore terminal.

74 MTPA

New receiving capacity under-construction, Q1 2015

Through 2020, global LNG receiving capacity will continue to grow and reach new markets. Out of the 17 terminals under construction as of early 2015 (not including terminal expansion phases), five were located in countries that will newly join the ranks of LNG importers: Egypt, Jordan, Pakistan, Poland and Uruguay. Still, the majority of under construction capacity – about 63% of the 74 MTPA total (including expansion phases) – will come from existing importers in Asia and Asia Pacific, primarily China, India and Japan.

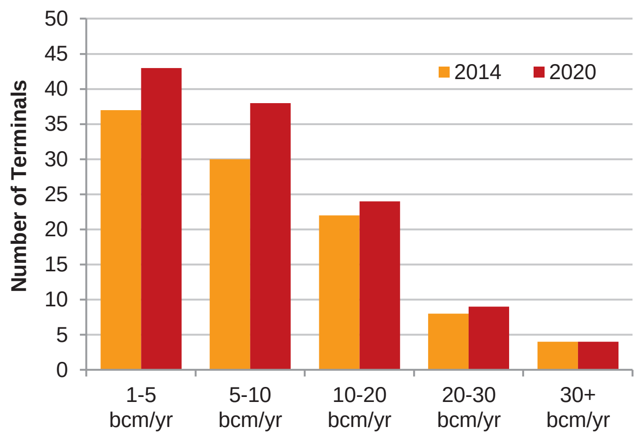


Figure 6.4: Annual Send-out Capacity of LNG Terminals in 2014 and 2020

Sources: IHS, Company Announcements

In 2014, the average utilisation rate of global LNG receiving capacity was 33%, about 1% less than in 2013. While 31 MTPA of new receiving capacity came online over the course of the year, LNG supply saw more modest gains, thus leading to lower overall utilisation. Not including the US, global utilisation was 41%. While the US has the second largest import capacity globally at 132 MTPA, it saw terminal utilisation fall under 1% in 2014 due to the continued boom in domestic shale gas production. Historically, the average global utilisation of LNG import terminals has remained below 50%, a result of the seasonal demand patterns in many gas markets.

The average maximum send-out capacity of regasification terminals has declined in recent years and amounted to 9.9 bcm/yr (7.2 MTPA) in 2014, down from 10.5 bcm/yr (7.6 MTPA) in 2012. This is largely a result of small to medium-sized terminals coming online in smaller markets. The growing use of floating terminals, whose capacity is generally below 6 MTPA, has also contributed to this.

6.3. RECEIVING TERMINAL CAPACITY AND UTILISATION BY COUNTRY

Japan remains the world's largest LNG import market, both by capacity as well as actual imports. Following the commercial start-up of the Hibiki LNG terminal in October 2014, the country's overall LNG receiving capacity increased to 190 MTPA, equivalent to 26% of the world's total. Three additional large-scale terminals or terminal expansion phases with a combined capacity of 3.5 MTPA were under construction as of the first quarter of 2015. Japan's dominant import position is not expected to change. Capacity utilisation stood at 47% in 2014, a minor decrease from 48% in 2013. Utilisation rates in Japan have typically averaged around 50% due to import seasonality.

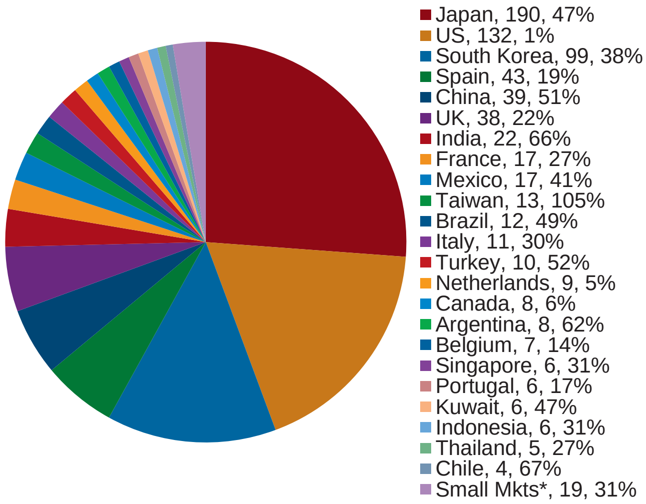


Figure 6.5: LNG Regasification Capacity by Country (MTPA) and Utilisation, 2014

Note: "Smaller Markets" includes the Dominican Republic, Greece, Israel, Lithuania, Malaysia, Puerto Rico and the UAE. Each of these markets has less than 4 MTPA of capacity.

Sources: IHS, IGU

China is the fastest growing LNG market and was the only country to bring online two new terminals (Hainan and Shandong LNG) in 2014. Its LNG imports as well as receiving capacity have increased significantly in recent years. China became the world's fifth largest regasification market by capacity in 2014 (39.5 MTPA, up from 6 MTPA in 2008) and remained the third largest importer by volume. Furthermore, seven new receiving terminals and two expansion phases with a total capacity of 28 MTPA were under construction as of early 2015. However, LNG demand growth remained below expectations in 2014. While China had an average terminal utilisation rate of 59% in 2013, this dropped to 51% in 2014.

Average terminal utilisation was highest in Taiwan (105%) and Puerto Rico (111%) in 2014. In contrast, Canada and the US – due to soaring domestic production – barely utilised their import infrastructure. Utilisation rates in most European countries also remained low (between 4% and 50%), although this will likely improve in 2015 in a looser LNG supply and lower price environment.

6.4. RECEIVING TERMINALS BY REGION

Capacity growth in both rising (China, India) and established (Japan, South Korea) markets in Asia and Asia Pacific has recently re-affirmed the continent's dominance in global regasification capacity. At 8% and 44%, respectively, more than half of global import capacity was located in these two regions as of end-2014. Combined, these regions also account for nearly 50% of the new capacity that came online in 2014, as well as 63% of under construction receiving capacity as of early 2015.

2012-2014 LNG Receiving Terminals in Review

Receiving Capacity

+66 MTPA

Growth of global LNG receiving capacity

Global regasification capacity expanded by 66.4 MTPA (10%) from 658 MTPA to 724 MTPA

This was mainly driven by capacity growth in Asia and Asia Pacific

Number of LNG Import Markets

+18

Number of new LNG import terminals

New and existing import markets alike have continued to bring online new LNG import terminals over the past three years.

The total number of active regasification terminals expanded from 88 to 101. The 102nd terminal (Arun LNG) came online in Indonesia in Q1 2015.

New LNG Importers

+5

New regasification markets

Number of LNG importing countries increased from 25 to 30 as Indonesia (domestic trade), Israel, Malaysia, Singapore and Lithuania added new terminals.

Four additional countries (Egypt, Pakistan, Jordan, and Poland) are set to commission their first terminal in 2015.

Offshore Terminals

+8

Number of new offshore LNG terminals

Out of the 18 new terminals that started operations, 8 were FSRUs.

FSRUs have offered a cost-effective solution to bring online regasification capacity and are a particularly attractive option for new and less-mature import markets.

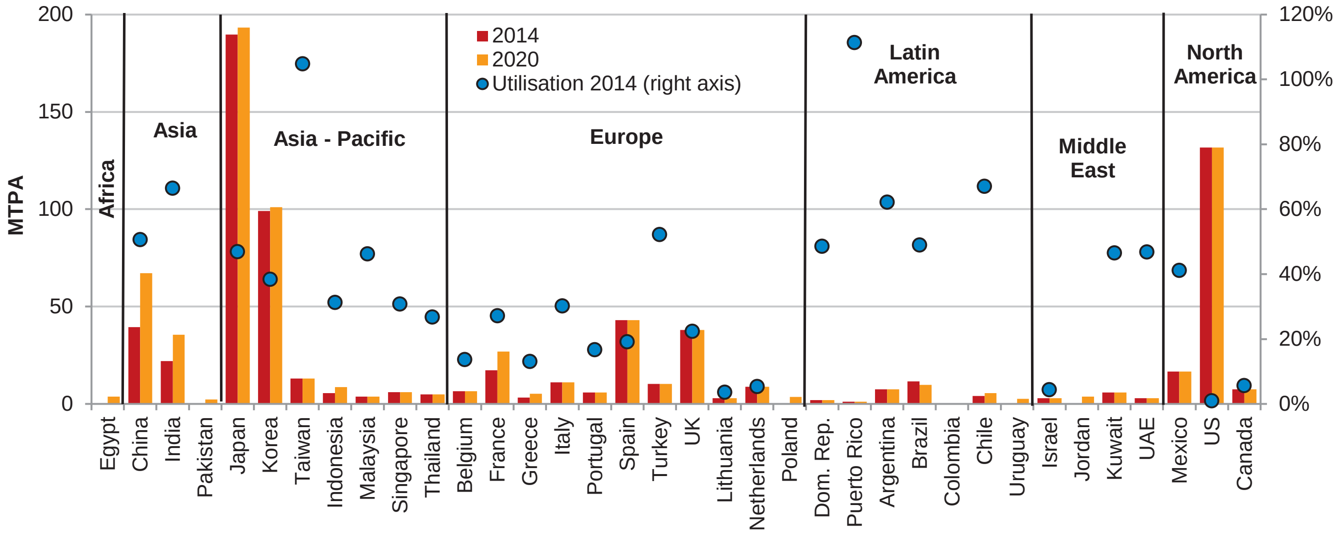


Figure 6.6: Receiving Terminal Import Capacity and Utilisation Rate by Country in 2014 and 2020

Sources: IHS, IGU, Company Announcements

All other regions – with the exception of North America – have also shown growth in recent years. Latin America and the Middle East were able to rapidly bring online new capacity through the use of FSRUs, although they still account for merely 4% and 2%, respectively, of worldwide capacity. Both regions have FSRUs under construction. Jordan will join the ranks of LNG importers as its FSRU is announced to start operations in the first half of 2015. In Latin America, Uruguay will become the region's newest LNG importer in 2016 thanks to the commissioning of an FSRU with a storage capacity of 263,000 cm.

In Europe, which holds 20% of global LNG import capacity, average utilisation – 22% in 2014, down from 26% in 2013 and 35% in 2012 – was among the lowest in years due to competition from pipeline gas. Despite the drop in European LNG imports since 2011, the region as a whole has continued to build new capacity. Lithuania joined the ranks of European importers in December 2014 when its new Klaipeda FSRU came online. Poland also has an onshore terminal (Swinoujscie) under construction, while existing importer France is in the process of finalising its new Dunkirk LNG terminal. Both terminals are scheduled for completion in the second half of 2015. With a receiving capacity of 10 MTPA, Dunkirk LNG will be one of the largest import terminals to come online in recent years. While there remain concerns about the lack of demand that has defined the European regasification market for the past four years, as of early 2015, importers in Europe are expected to again benefit from a more favourable LNG supply and price environment.

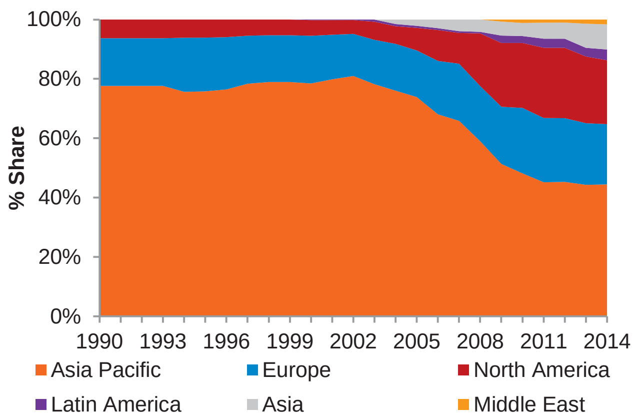


Figure 6.7: Regasification Capacity by Region, % Share of Total, 2014

Sources: IHS, Company Announcements

North America is still home to 22% of global LNG import capacity, but terminals in the region continue to be minimally utilised, if at all. The prospect of ample, price-competitive domestic gas production means that this is unlikely to change going forward. Many terminal operators are now instead focusing on adding export liquefaction capacity to take advantage of the shale gas boom.

6.5. RECEIVING TERMINAL LNG STORAGE CAPACITY

As new terminals began operations in 2014, global LNG storage capacity increased slightly to 50 mmcm. With 101 active terminals worldwide as of early 2015, this equals an average terminal storage size of just below 500 mcm.

However, some terminals are significant outliers in this regard. Onshore terminals in Asia generally have larger capacity to allow for greater flexibility and security of LNG supply during periods of peak seasonal demand. Importers like China, Japan, India and South Korea also often have little gas storage available outside of LNG terminals. Capacity at the 20 largest LNG storage terminals ranges from 0.5 to 2.6 mmcm and accounts for 41% of the world's total. Fourteen of these terminals are located in South Korea and Japan. South Korea's

Samcheok LNG terminal, which started operations in the third quarter of 2014, had the world's largest LNG storage tank as of early 2015, with a capacity of 270,000 cm. The terminal will have a total storage capacity of 2.34 mmcm, though only 500 mcm was in operation as of early 2015.

LNG storage capacity at the majority of terminals stands in the 100 to 500 mcm range. In line with terminal send-out capacity, the increased use of FSRUs in emerging markets has been accompanied by smaller storage, as storage at floating terminals is typically between 125 and 170 mcm. With a storage capacity of 263 mcm, Uruguay's GNL del Plata FRSU – set to come online in 2016 – will become the world's largest FSRU to enter operations.

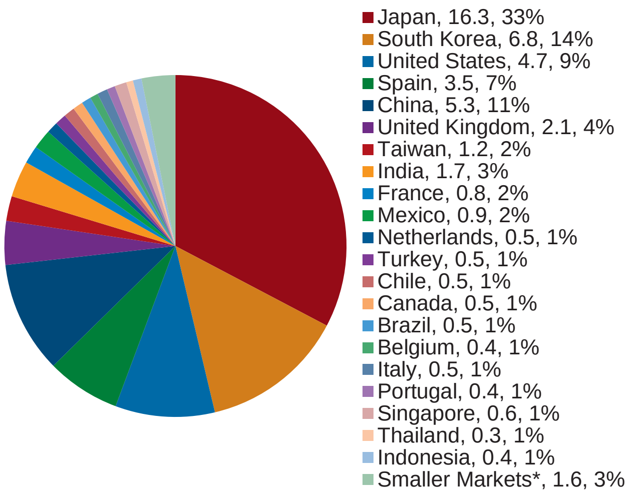


Figure 6.8: LNG Storage Tank Capacity by Country (mmcm) and % of Total, as of Q1 2015

Note: "Smaller Markets" includes Argentina, the Dominican Republic, Greece, Israel, Kuwait, Malaysia, Puerto Rico and the UAE. Each of these markets has under 0.3 mmcm of capacity.

Sources: IHS, Company Announcements

6.6. RECEIVING TERMINAL BERTHING CAPACITY

Similar to LNG storage developments, two divergent trends have emerged in terms of terminal berthing capacity. On the one hand, terminals in higher-demand markets have generally increased their berthing capacity to accommodate larger vessels, particularly Q-Class carriers with a capacity of over 200,000 cm. On the other hand, many emerging, lower-demand import markets – and particularly those making use of FSRUs with limited storage capacity – are largely only able to receive smaller conventional vessels with a capacity below 200,000 cm.

At end-2014, 34 out of 101 active regasification terminals worldwide in 14 different import markets were capable of receiving Q-Max vessels, which have a capacity of 261,700-266,000 cm. Half of these terminals were located in Asia and Asia Pacific, and none in Latin America or the Middle East. Two-thirds of import markets had at least one terminal capable of receiving Q-Class vessels. The notable exception to this is Taiwan, the world's fifth largest LNG importer in 2014, which is only able receive conventional vessels. Of the 30 terminals that are only able to receive conventional vessels, 14 are FSRUs.

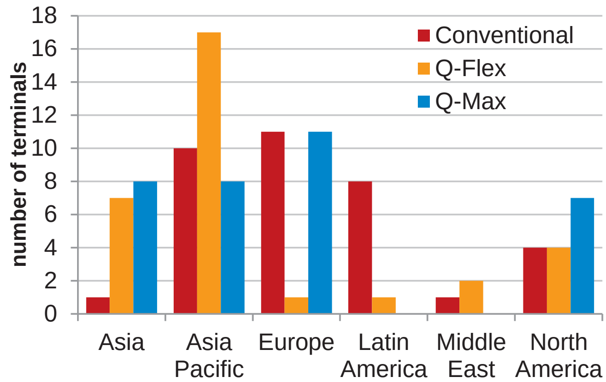


Figure 6.9: Maximum Berthing Capacity of LNG Receiving Terminals by Region, 2014[6]

Sources: IHS, Company Announcements

6.7. FLOATING AND OFFSHORE REGASIFICATION

Especially nascent import markets have increasingly relied on the use of FSRUs to secure access to LNG supplies in recent years. As of end- 2014, 11 out of 30 import markets had floating capacity (though four of these markets also had onshore capacity). With four additional floating terminals in new import countries under construction, from mid-2015 on nearly half of all import markets are expected to have at least one FSRU in operation.

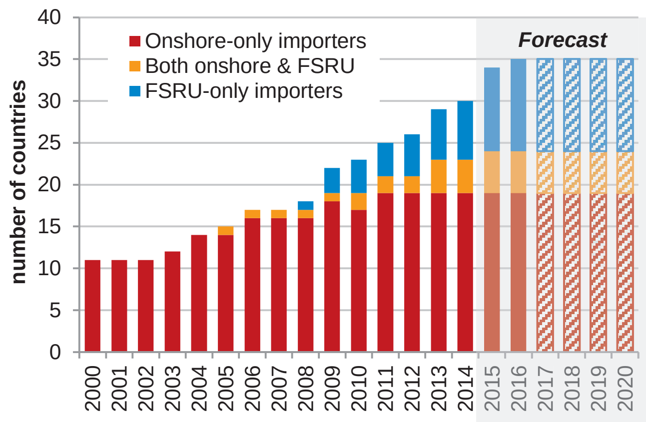


Figure 6.10: Rise of FSRUs among Import Markets, 2000-2020

Sources: IHS, Company Announcements

Note: The above graph only includes importing countries that had existing or under construction LNG import capacity as of end-2014. As indicated by the diagonal bars, additional countries could become LNG import markets post-2016 should new terminals be sanctioned.

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

In 2014 alone, three new floating regasification terminals began operations: Brazil's Bahia/TRBA in early 2014, Indonesia's Lampung LNG in July, and Lithuania's Klaipeda LNG in December. Moreover, two other terminals completed expansions during the year: a larger FSRU replaced a smaller unit at the Mina al Ahmadi terminal in Kuwait, while a newly-completed FSRU with increased capacity also replaced a smaller vessel at Brazil's Guanabara terminal. At the end of 2014, total active floating import capacity stood at 54 MTPA at 16 terminals.

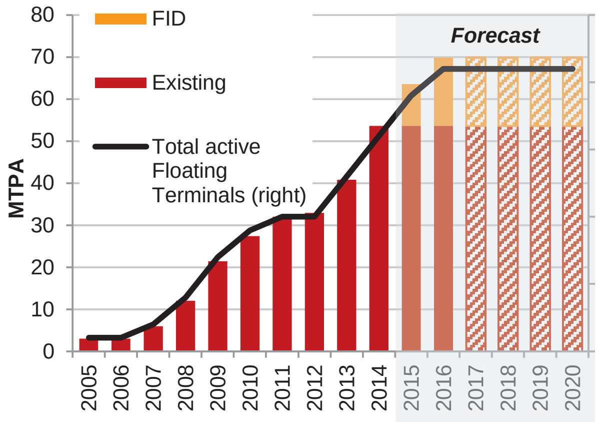


Figure 6.11: Active Floating Regasification Capacity by Status and Number of Terminals, 2005-2020
Sources: IHS, Company Announcements

Note: The above forecast only includes floating capacity sanctioned as of end-2014. As indicated by the diagonal bars, additional FSRU capacity that has not yet been sanctioned could come online after 2016.

Five additional FSRUs, totalling 16.2 MTPA of capacity, were under construction as of early 2015. Three of them – all announced to come online in 2015 – will be located in countries new to the LNG market: Egypt, Jordan and Pakistan. Two additional FSRUs are set to start operations in Uruguay (GNL Del Plata) – also a new importing country – and India (Kakinada) in 2016.

There are several advantages, but also risks associated with floating regasification solutions.

Two important advantages, particularly for less mature LNG importers, are that floating terminals can generally be brought online in a shorter period of time (thus allowing for rapid fuel switching) and at a lower capital cost (see Section 6.9. for further information). Without the need to construct significant onshore facilities, floating solutions in many cases offer greater flexibility when there are either space constraints onshore or no suitable ports. FSRU vessels can also be linked to an offshore buoy that connects into a subsea gas pipeline system and can therefore operate further offshore than conventional terminals. Additional advantages include a possibly easier and shorter permitting process, as well as much lower CAPEX as FSRUs are normally chartered from a third party.

Potential risks associated with offshore terminals mainly pertain to the FSRU's operability. They include vessel performance, heavy seas or meteorological conditions, and a longer LNG deliverability downtime. There are also limitations in terms of both send-out and storage capacity, which for FSRUs are typically much lower than for larger onshore facilities – and can thus create impediments and limitations for onloading operations. While the CAPEX of FSRU terminals is lower, OPEX, in contrast, is much higher due to the time charter associated with the vessel.

FSRUs are generally distinguished by two categories of vessels with distinct technical capabilities. First, FSRUs that function as permanently moored regasification terminals and which generally operate in a single country on a long-term basis – although the vessels used for these operations can also be substituted. Second, there are mobile FSRU vessels that are usually contracted to different import markets for a dedicated and short period. When not under contract, these FSRUs can operate as normal LNG carriers that also have the possibility to come to a port loaded and stay only for the time required to regasify their cargo.

6.8. RECEIVING TERMINALS WITH RELOADING AND TRANSHIPMENT CAPABILITIES

The LNG re-export trade has expanded rapidly since 2011, driven by Europe, where weak gas demand has encouraged shipping cargoes to more lucrative end markets. Spain is by far the largest re-exporter. All six of the country's regasification terminals are now equipped with re-export infrastructure as three terminals – Barcelona, Sagunto (Saggas) and Bilbao – added reload capabilities in 2014. Two new FSRUs that started operations in Brazil during 2014 – Guanabara LNG in Rio de Janeiro and Bahia/TRBA in Bahia – also have reload capabilities, bringing the total number of terminals able to re-export cargoes to 19 in nine different countries. Singapore's Jurong Island terminal and India's Kochi terminal, too, conducted first reloads in the first quarter of 2015.

Europe has dominated the re-export market in recent years, with the majority of cargoes going to higher-demand regions in Latin America and Asia Pacific. However, as the global LNG market is expected to loosen in 2015 and beyond as new liquefaction projects come online, price differentials between regions may be less pronounced, challenging the economics of the LNG reload trade.

Beyond Europe, re-exports have often been limited, sometimes to just one cargo. This was markedly the case with the single re-export from Costa Azul in Mexico in 2011. Other facilities, such as Cove Point in the US or Canaport in Canada, have been authorised to re-export, but decided not to pursue this option as they have instead focused on adding liquefaction capacity.

Country	Terminal	Reloading Capability	Storage (mcm)	No. of Jetties
Belgium	Zeebrugge	4-5 mcm/h	380	1
Brazil	Rio de Janeiro	10.0 mcm/h	171	2
Brazil	Bahia Blanca	5 mcm/h	136	1
Brazil	Pecém (OS)	10 mcm/h	127	2
France	FosMax LNG	4.0 mcm/h	330	1
France	Montoir	4.5 mcm/h	360	2
Mexico	Costa Azul	N/A	320	1
Netherlands	GATE LNG	2.5 mcm/h	540	2
Portugal	Sines	3.0 mcm/h	390	1
S. Korea	Gwangyang	N/A	530	1
Spain	Cartagena	3.5 mcm/h	587	2
Spain	Huelva	3.7 mcm/h	620	1
Spain	Mugardos	2.0 mcm/h	300	1
Spain	Barcelona	3.5 mcm/h	760	2
Spain	Bilbao	3.0 mcm/h	450	1
Spain	Sagunto	6.0 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 6.1: Regasification Terminals with Reloading Capabilities in 2014

** Reloading capacity permitted by the US DOE*

Sources: IHS, IGU

In addition to reloading capabilities, some terminals (e.g. the Montoir-de-Bretagne import terminal in France) that have 2 jetties have focused on developing direct ship-to-ship LNG transfer capabilities. GATE LNG in the Netherlands also plans to add this functionality in 2015.

6.9. PROJECT CAPEX

The CAPEX requirements for regasification terminals generally include the berthing, storage, regasification, send-out pipelines and metering of new facilities. While CAPEX costs for new import terminals were relatively constant in the period between 2005 and 2011, they have risen significantly since then – and are expected to further increase through 2017 for under construction capacity. There are considerable differences in CAPEX between onshore and floating terminals, with costs for the latter being consistently lower. This is mainly the result of the more limited infrastructure requirements for an FSRU, as well as the fact that the vessel charter itself is considered as an OPEX by the project developers.

$212/tonne
Average costs of new onshore LNG import capacity in 2014

The weighted average unit cost of onshore regasification capacity that came online in 2014 – based on a three-year moving average – was $212/tonne, up from a relatively steady average cost of $110/tonne between 2008 and 2010. For onshore capacity under construction as of the first quarter of 2015, costs are expected to escalate further and peak at almost $350/tonne in 2016 before starting to decline. The rise in onshore regasification costs is closely associated with the trend of increased LNG storage capacity. As countries – mainly in high-demand regions like Asia and Asia Pacific – add larger storage tanks to allow for higher imports and greater supply stability, the storage capacity size per unit of regasification capacity has increased. This correlation also holds true beyond 2017, when several new onshore terminals with smaller storage units are expected online, bringing down overall costs.

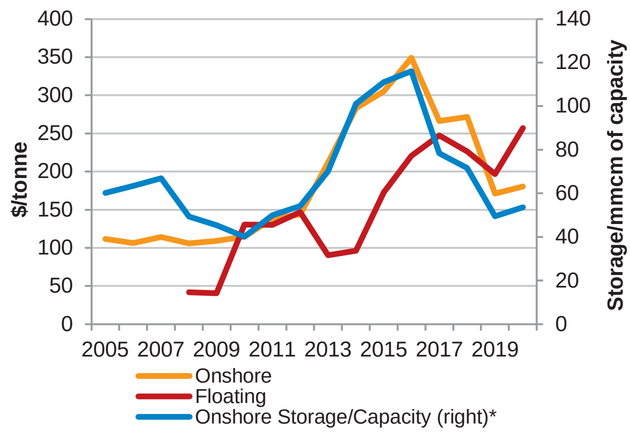


Figure 6.12: Regasification Costs based on Project Start Dates, 2005-2020

** Indicates the size of onshore storage relative to onshore terminal regasification capacity*

Sources: IHS, Company Announcements

Costs for new floating terminals have also held steady for a longer period of time, with only currently under construction floating projects being subject to greater cost escalation. As with onshore terminals, larger vessels – and thus greater storage and send-out capacity – have entailed higher CAPEX. In 2014, the weighted average unit cost of floating regasification based on a three-year moving average was $96/tonne. This is expected to more than double in 2017. Still, overall CAPEX for floating terminals is generally less volatile than for onshore facilities, which is partly a reflection of lesser variations in capacity and storage size for vessel-based terminal solutions.

6.10. RISKS TO PROJECT DEVELOPMENT

Regasification facilities are typically easier to develop than liquefaction projects, both from an engineering and construction standpoint. In the case of FSRUs, import terminals can be brought online in a shorter timeframe and can start operations without the need for significant land-based construction work.

Still, factors that can obstruct or delay the successful implementation of a new import project planning and construction schedules are similar to those that typically affect liquefaction plants. They include:

- **Permitting, approval and fiscal regime.** The permitting and approval process for new terminals, can significantly delay the construction start of a new terminal. This was the case for Italy's Livorno/LNG Toscana import facility, which in late 2013 came online more than two years behind schedule as the terminal developers navigated the complex set of permits required by Italian authorities. Similarly, a stable and attractive fiscal regime can be a key component supporting or inhibiting new regasification terminal projects.

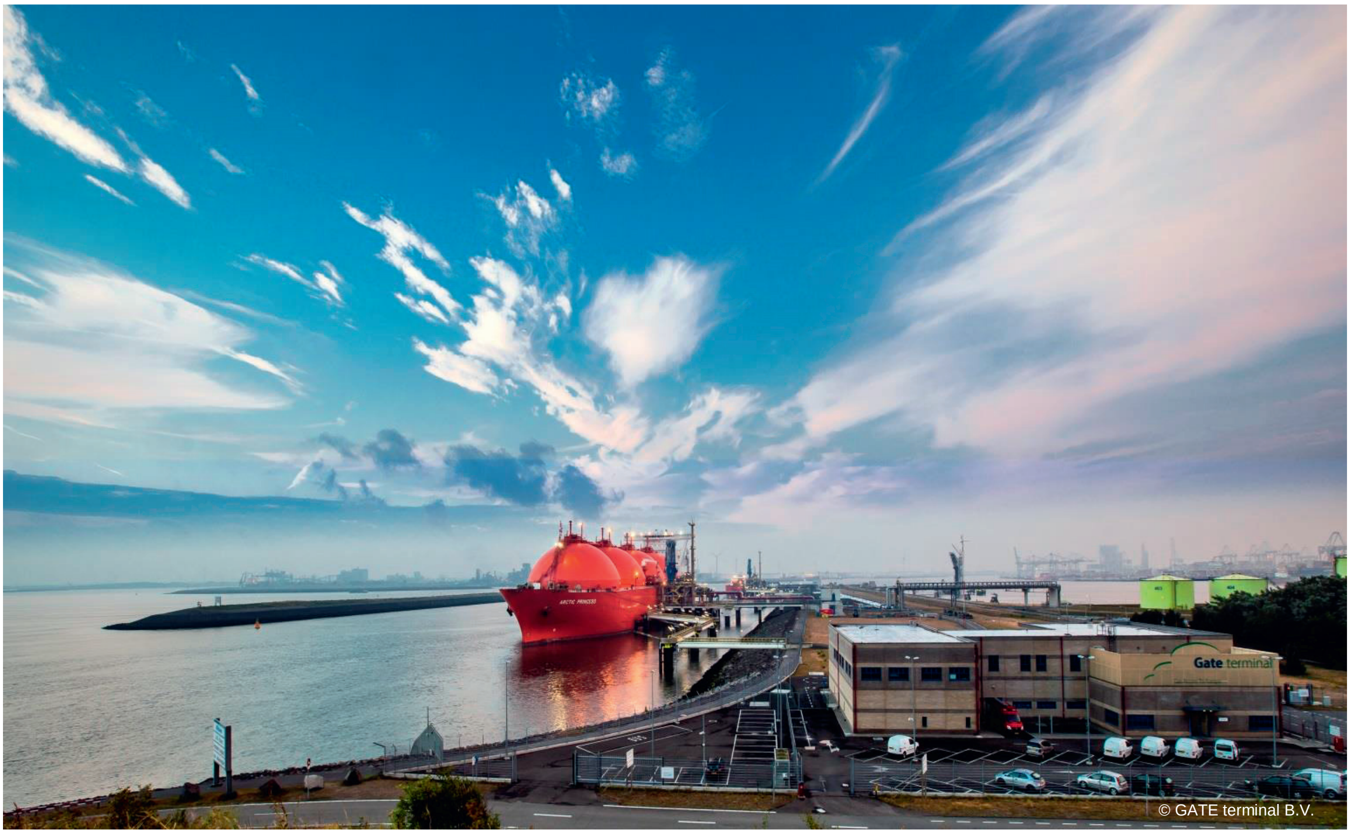
- **Project and equity financing**, which are a prerequisite for project development and execution. The delivery of an FSRU as a new floating LNG import terminal in Egypt was initially rejected by the vessel owner due to a lack of financial guarantees. A final agreement was only reached in November 2014. The under construction terminal is now expected to come online in 2015 – more than three years after Egypt had initiated the tender process.

- **Conclusion of long-term regasification and offtake contracts** with terminal capacity holders and downstream consumers. India's Kochi LNG terminal, which came online in November 2013, was mechanically complete in December 2012, but supply agreements with downstream consumers were not immediately finalised due to pipeline constraints. This delayed commercial start-up until November 2013.

- **Reliability and liquidity of contractors and engineering firms** during the construction process. Poland's under construction Swinoujscie terminal was initially planned to come online in mid-2014. However, the financial difficulties of several Polish contractors pushed back the announced start date.

- **Associated terminal infrastructure** such as pipelines or port work necessary to connect a terminal to the grid and receive ships, which are often separate infrastructure projects that are not planned and executed by the terminal owners themselves. The Kochi LNG import facility in India initially had to operate far below capacity as surrounding pipeline connections to the Indian grid had not been completed in time.

- **Difficult climatic conditions** can also impede terminal developments. In South Africa, plans for the country's proposed floating Mossel Bay project were cancelled in 2014 after FEED studies indicated that the difficult meteorological and oceanographic conditions in Mossel Bay were not suitable for an offshore terminal.



© GATE terminal B.V.

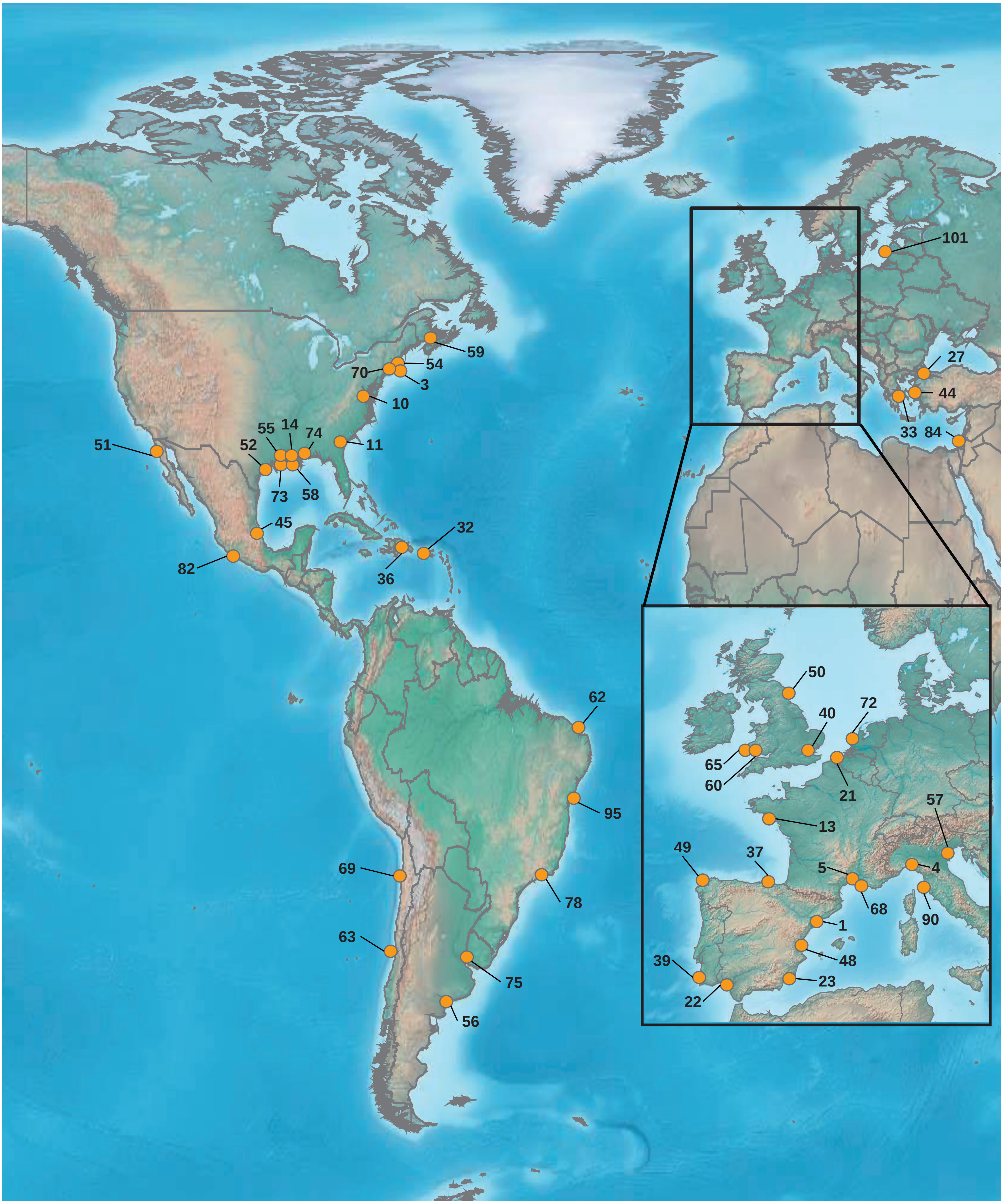
Looking Ahead:

Which countries will seek to build new regasification terminals in the years ahead? *Since 2000, the number of LNG importing countries has tripled. These new markets have formed an integral part of the growth in global regasification capacity. Five additional countries – Egypt, Jordan, Pakistan, Poland and Uruguay – have new capacity under construction and are expected to commission their first import terminal in 2015-16. While existing importers, particularly in Asia and Asia Pacific, will continue to expand their receiving capacities, long-term growth will depend on the successful development of new terminals in aspiring markets such as Bangladesh, Ghana, Ireland, Jamaica, South Africa or Vietnam. All of these markets have proposed regasification projects, but political, developmental, or financial hurdles have thus far prevented a final investment decision.*

Will terminals reloads continue in light of narrowing regional price differentials? *There were 21 different import terminals in 11 countries capable of re-exporting LNG cargoes as of the first quarter of 2015. European importers in Spain, France and the Netherlands in particular have focused on adding reloading capabilities to re-export cargoes in a continually low LNG demand environment in Western Europe since 2011. They were joined by terminals in South Korea, Singapore and elsewhere, which also adapted their facilities for reloads. However, a loosening LNG supply environment and a narrowing of price differentials between basins in early 2015 has altered the market conditions that previously formed the basis for re-exports. Traders are starting to use LNG terminals as storage in a "contango" environment, triggered by time spreads rather than regional market spreads.*

Will markets continue to turn to floating terminals to enter the LNG market? *FSRUs offer a short-term, cost-effective and quick to market solution to bringing online regasification capacity, especially for new and less-mature import markets with moderate or variable demand. Floating terminals continue to make up an increasing share of global under construction capacity: of the four countries that will become new importers in 2015, three will have an FSRU as their first import terminal. In addition, existing importers like Brazil or Kuwait have decided to increase capacity at their floating terminals by employing larger size vessels. But floating terminals also face constraints: their storage and berthing capacity is generally much lower than that of onshore facilities and OPEX are much higher because of the time charter vessel. As nascent LNG markets mature, they may ultimately seek to move to onshore solutions. Still, FSRU demand is expected to remain strong as ever more countries turn to LNG to secure their energy needs.*

Simultaneous Loading at GATE



101
59
54
70
3
10
27
44
33
84
55
14
74
52
51
11
73
58
45
32
82
36
50
40
72
65
60
21
57
13
49
37
5
4
68
90
1
48
39
23
22
62
95
69
78
63
75
56

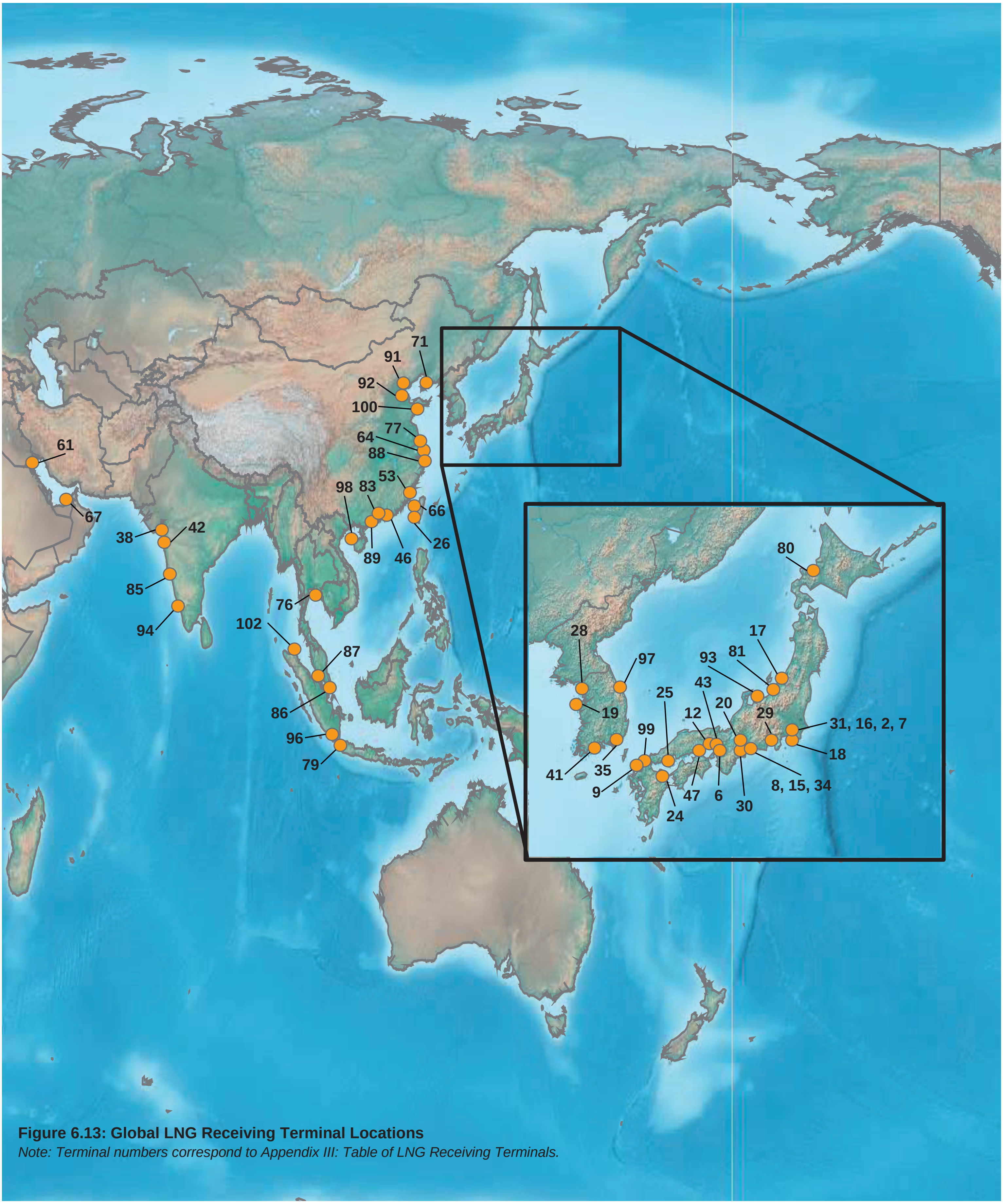


Figure 6.13: Global LNG Receiving Terminal Locations

Note: Terminal numbers correspond to Appendix III: Table of LNG Receiving Terminals.

7. Special Report – LNG as Fuel

This special report explores the evolving role of LNG as the physical form of natural gas consumed in engines across all industries that use hydrocarbon energy – transportation in road, rail, marine and aviation, heavy machinery, mining, drilling, agriculture and power generation. Whether principle interests relate to the regulatory or environmental drivers, the economic or commercial incentives, or the health and safety aspects of operations, all participants in this fuel evolution should be aligned for success. A key enabler in the evolution of LNG as a fuel is the growth and availability of small-scale LNG or SSLNG (please refer to the Special Report on SSLNG in Chapter 8 for further information). The goal of this study is to increase awareness of the rapidly evolving LNG as fuel business and promote informed discussion of tangible next steps for a safe, economic and reliable industry.

A full report dedicated to this subject is available on the IGU website at http://igu.org/publications/LNGasFuel.pdf

7.1. ENVIRONMENTAL DRIVERS

There is growing global interest to reduce emissions. According to the US Energy Information Agency's (EIA) 2014 International Energy Outlook reference case, world petroleum and other liquids consumption is forecasted to grow by 38% between 2010 and 2040. This increased consumption will be accompanied by growth in associated greenhouse gas (GHG) emissions, forecasted to increase 45% by 2040. The world is on a trajectory toward long-term temperature increases, far above the internationally agreed target. As a result the global climate debate is driving change for cleaner burning gas and alternate fuels.

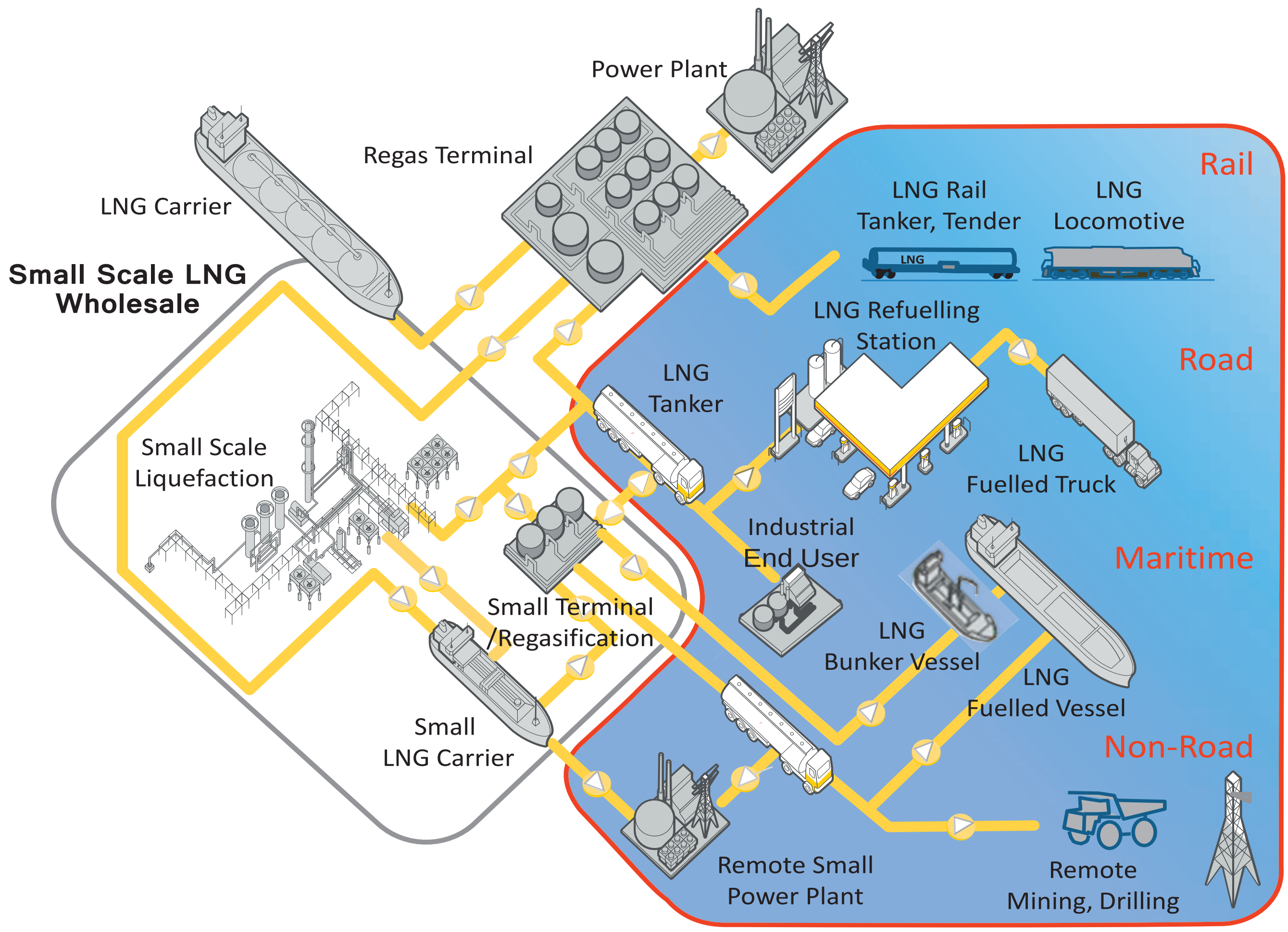


Figure 7.1: LNG as Fuel Applications

Source: Shell

From an environmental emissions perspective, LNG as fuel is a viable mitigant, significantly reducing emissions of carbon dioxide (CO_2) by up to 20%, sulfur oxide (SOx) up to 100%, nitrogen oxide (NOx) up to 90%, and particulate matter (PM) up to 99%. The maritime industry is the low hanging fruit leading the transition to LNG as fuel, primarily due to global concern about SOx emissions.

The On-Road transportation sector, which is the largest contributor to transportation emissions, has the potential to have the greatest impact on reducing emissions by using LNG as a fuel supply in the heavy vehicle fleet, characterised by high utilisation on defined corridors and regular schedules.

7.2. BUSINESS DRIVERS

The outlook for LNG as fuel is very positive and continues to gain momentum. Market pull from owners and operators of ships, buses, heavy trucks, locomotives and drilling equipment has caused engine manufacturers to begin designing and building a range of natural gas and dual fuel engines for use with LNG. The engine industry seems to be in an evolutionary phase and will need added time to meet the needs of all customers as they evaluate and test these new engines for economical business solutions.

The On-Road transportation sector driven by commercial fleet owners in LNG-fuelled vehicles has grown significantly over the past decade. In China, major LNG corridors already exist and in Europe the Blue Corridors project is underway to build LNG fuelling infrastructure and to demonstrate the economic viability of LNG fuel for heavy trucking to encourage growth.

134 ships
# of LNG-fueled ships in operation and on order as of January 2015

The Maritime transportation sector is rapidly developing LNG as fuel capability with 134 LNG-fuelled ships in operation or on order as of January 2015. By 2020, DNV GL expects 1,000 newbuilds to be delivered with natural gas engines. Additionally, 600 to 700 ships could be retrofitted to run on LNG. After 2020, an estimated 30% of newbuilds in the global fleet annually will be LNG-fuelled.

The Non-Road transportation sector is making advances using LNG as a fuel supply for mining and drilling operations, remote small-scale power barges, remote community and industrial fuel supplies, railway locomotive test programs, and very long lead time aviation research.

A dilemma exists between the level of LNG demand and the availability of LNG supply and distribution, with owners on both sides of the business depending on the other to anchor new investments. As a result, cooperatives and

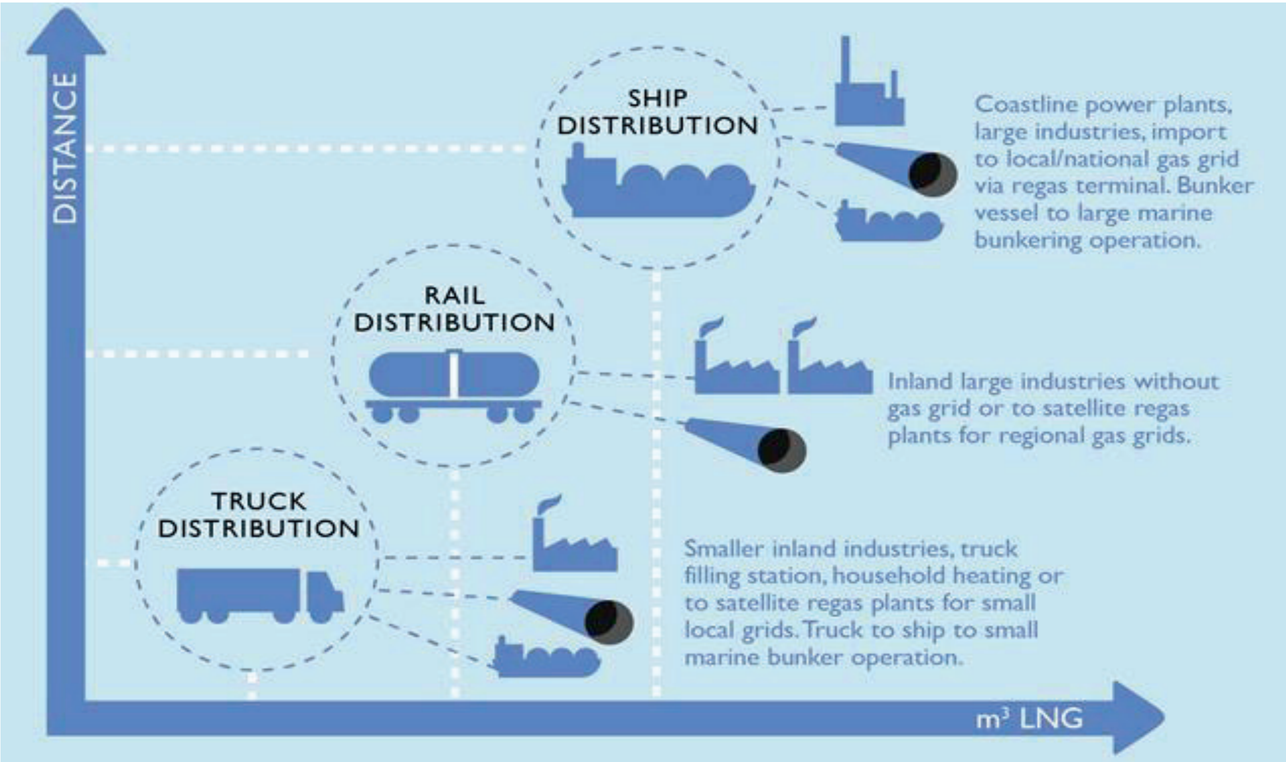


Figure 7.2: LNG Distribution Options as a function of Volume and Distance
Source: Swedegas AB

partnerships are being formed to mitigate commercial risks, align business interests and move supply and demand projects forward in parallel. The value can be captured by those willing to take the risk and make first-mover investments.

A potential benefit for all end users may be the fuel cost savings of gas relative to diesel fuel costs if the price differential in some regions becomes a sustainable reality. The current oil price cycle poses a challenge for LNG as Fuel applications and is expected to delay greater acceptance and implementation due to owners' preference to use lower cost fuels and utilise abatement measures. Furthermore, if LNG is taxed on a volumetric basis, this could be detrimental for LNG because it has lower energy content per unit volume than diesel.

7.3. ATTENTION TO SAFETY

The LNG industry has created an enviable track record of safety in operations and transport. Many government and industry entities have published a number of excellent guidelines and checklists. However, with a growing number of participants along the value chain, there is a challenge that all parties conform to the same high level of attention to safety. A single LNG incident could impact public perception causing a ripple effect that could negatively impact the broader gas industry.

Primary risks associated with LNG as fuel tend to be related to LNG transport and cargo transfer at a smaller scale than current industry norms. LNG tank trucks on roadways, bunker vessels in ports and harbours, and methane slippage during connections are the key areas of interest for heightened safety awareness. Training is the principal means of minimising the chance of human error. Regular inspection and preventive maintenance should avert use of damaged equipment. Use of interconnector fittings is the existing safeguard to make leak-tight connections.

Moving forward, the industry needs to ensure that safety information on all aspects of LNG transfer, transport and dispensing is widely disseminated to any stakeholder interested in LNG as fuel. Industry, local government authorities and first responders must coordinate effectively to maintain a high level of awareness of LNG-related activities and ensure all stakeholders are engaged in promoting a culture of safety.

© IndianOil

8. Special Report – Small-Scale LNG (SSLNG)

Fifty years ago, the first commercial LNG cargo was shipped from an LNG export facility in Algeria in 1964. Since then, LNG has grown into a truly global commodity. This growth has been accompanied with, and driven by, economies of scale in the design and construction of facilities. Since the 0.4 MTPA LNG trains in Algeria, the conventional LNG business has evolved into 7.8 MTPA mega-trains in the 77 MTPA Ras Laffan Industrial City in Qatar.

20 MTPA
Installed SSLNG capacity in 2014

In recent years, a comeback of smaller scale LNG facilities has emerged. New liquefaction and distribution facilities are being constructed and operated across the globe. Currently, the SSLNG installed production capacity is of 20 MTPA spread around hundreds of SSLNG facilities. This is on top of the installed capacity for conventional LNG plants of approximately 300 MTPA. The SSLNG market is developing rapidly, especially as a transportation fuel and to serve consumers in remote areas or not connected to the main pipeline infrastructure.

The IGU defines small scale liquefaction and regasification facilities as plants with a capacity of less than 1 MTPA, whilst SSLNG carriers are defined as vessels with a capacity of less than 30,000 cm. Figure 8.1 describes a value network with a number of value chain configurations. An SSLNG chain can either be associated to a conventional LNG value scheme or be a standalone scheme comprising SSLNG terminals, liquefaction plants and transportation modals such as ships, trucks and rail.

The global commoditisation of LNG has provided a solid base for the emergence of new LNG applications and markets. The key drivers for SSLNG are environmental, economic and geopolitical. The environmental benefits of LNG in terms of CO2, SOx, NOx and particulate emissions are undisputed when compared to alternative fossil fuels, but it also needs to have a transparent and profitable business model to be feasible.

The supply chain can be rather expensive due to the diseconomy of the small scale and the relatively small size of the market, but as technology solutions mature, standardisation, modularisation and therefore competitiveness are increasing. The lower entrance hurdle compared to large LNG projects opens up opportunities for creativity and fast new technology deployment.

21 MTPA
Expected installed SSLNG capacity in China by 2020

Most of the growth is in China where efforts are in place to get clean fuels to fight air pollution in the cities, stimulated by the availability of gas and the price differential between natural gas and diesel. By 2020, the total installed capacity for SSLNG plants in China is expected to reach 21 MTPA.

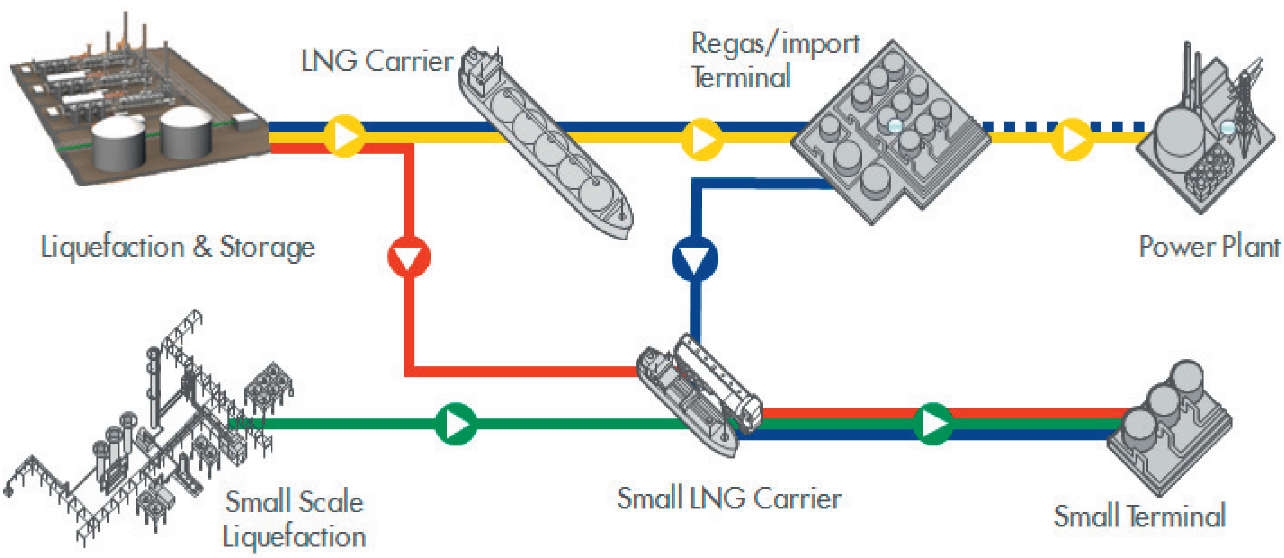


Figure 8.1: LNG Value Network

Source: Shell

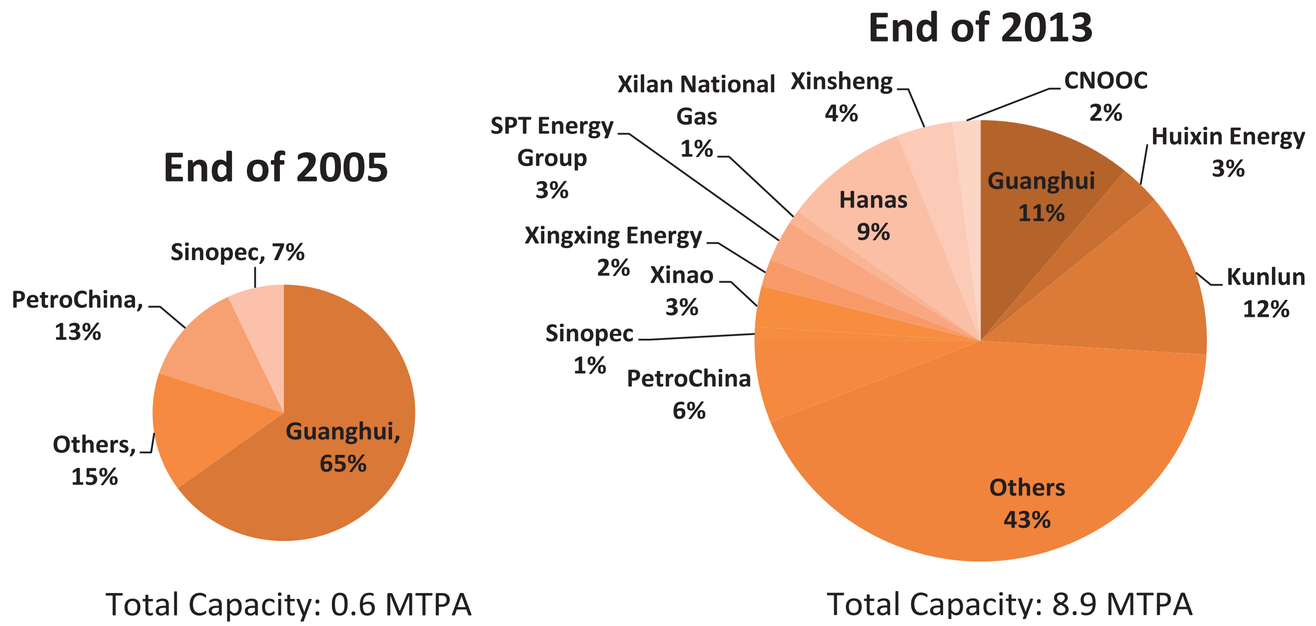


Figure 8.2: Chinese Liquefaction Plant Evolution

Source: Shell

Price arbitrage is a primary driver in the US with the abundance of shale gas. Stricter regulations on the marine sector are boosting the use of SSLNG as bunker fuel in Europe (Scandinavia, Baltic and Northwest Europe). In Latin America, the key drivers are the monetisation of stranded gas supplies and the need to reach remotely located consumers. Significant SSLNG import, break bulk and regasification is already present in China, Japan, Spain, Portugal, Turkey and Norway with hundreds of small terminals; it continues to grow to service remote local areas and fluctuating consumption profiles.

The development and maturation of SSLNG technology are key enablers for the pursuit of the SSLNG business. Here, significant progress has been made in all areas of the value chain. In the liquefaction plants, the development and optimisation of a wider range of processes and equipment helped to counter the diseconomy of small scale and to reduce initial investment cost. The application of pressurised LNG tanks provides a more cost-effective means for storing smaller parcels of LNG when compared to the conventional atmospheric flat bottom tanks. It also allows for a more effective way to manage Boil-Off Gas (BOG) and pressure build-up across the value chain, thus eliminating the need for more expensive BOG compression solutions. Developments in shipping (cargo containment systems, commoditisation) and transfer (ship-to-ship transfer, Emergency Shutdown and Release Systems) also support the trend towards more fit for purpose solutions in SSLNG. New project

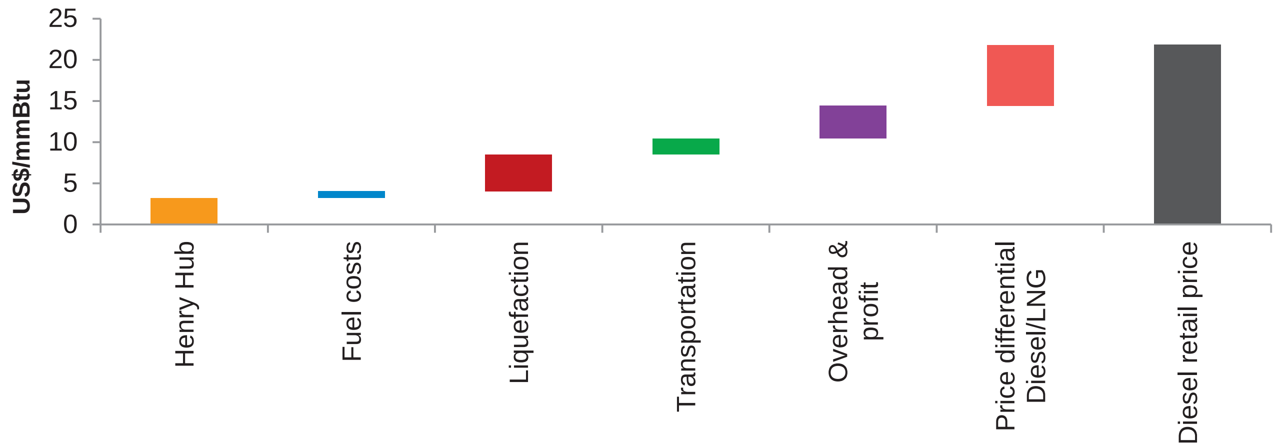


Figure 8.3: Diesel and LNG Price Differential in the US (January 2015)

Source: Adapted from PlumEnergy (May 2013), Great Lakes Maritime Research Institute (public domain), EIA execution principles such as modularisation, containerisation, replication and standardisation enable further growth of LNG. SSLNG creates opportunities for lean operational and maintenance strategies such as unmanned operation and multi-disciplinary staff.

However, there are still many challenges. One of the challenges of SSLNG globally is meeting the security of supply and demand, for example to overcome the concern of customers to step into the SSLNG market with only limited supply alternatives available. The development of downstream infrastructure and logistics – remote regasification facilities, bunkering and trucking stations – is key for building up a robust market for SSLNG. In order to achieve this, cost-effectiveness, modularisation and standardisation will be crucial. Another challenge is the implementation of a fiscal regime and a regulatory framework conducive to foster investment in SSLNG opportunities.

An important consideration is the impact of the recent drop in oil prices in the investment decision for natural gas and LNG projects. This is expected to affect the SSLNG business in particular due to its fast-responding nature and because these projects require large oil/gas price differentials that may no longer be available in the current oil price scenario.

Historically, LNG has displayed a very good safety track record. The very high reliability and safety level achieved by the traditional LNG industry does not guarantee that the same safety standards can be maintained for the small-scale business due to the many differences between the two businesses. For example, due to the large number of smaller parcels and multiple players in a rapidly growing market, the SSLNG business is scattered and more challenging to manage. Sharing of best practices, developing consistent national and international safety standards and creating a certified training level for staff involved in SSLNG is needed to maintain the high safety standards of the industry.

The expectation for the SSLNG business is that the expansion will continue towards 2020, growing towards a 30 MTPA business globally. This growth is predicated on the implementation of a level playing field, with economic incentives and robust environmental regulations, on technology developments driving down costs, and on the sustainability of a competitive price spread between natural gas and oil.

A full report dedicated to this subject is available on the IGU website:
http://igu.org/publications/SmallScaleLNG.pdf

LNG Plant, Kwinana, Australia (61 KTPA)

9. Special Report – Remote LNG

9.1. INTRODUCTION

With natural gas advancing its position in the world energy mix, exploration activity – historically focused on oil – now embraces gas with the same enthusiasm. Today it is the gas discoveries that are dominating the headlines.

Driven by demand, technological advances and viable economics, LNG is allowing the development of gas discoveries in more and more remote and hostile regions of the globe. As exploration moves into these new frontiers, liquefaction projects will similarly be located in increasingly distant and hostile areas. Perhaps considered the most hostile region of all, the Arctic Circle provides some of the most challenging projects for LNG today and looks to be one of the biggest growth areas in the coming 20-30 years of exploration.

The purpose of this IGU report is to review the new and challenging remote and hostile regions where LNG projects are being planned and could be located in the future, and discuss the particular challenges that are faced in the whole chain, from site selection through design and construction to the operation and export of LNG from these plants. Whilst FLNG can be considered as a very remote concept, it was decided to exclude FLNG from this discussion due to the very specific nature of the concept.

Source: Novatek

The term "remote" or "R" generally implies a significant distance from a particular place, and it is fair to say that, by definition, the majority of LNG production projects are in geographically isolated areas. The driving force behind liquefaction projects has always been the need to monetise and transport isolated gas reserves in an economic way to markets anywhere in the world. However, this report proposes to include other factors into the term "remote" to give a more complete indication of the challenges that are faced by complex projects in complicated areas of the world.

Therefore, a **Remoteness Index** has been developed and presented by the IGU study group on Remote LNG. The Remoteness Index quantifies just how remote and hostile a particular project is and, based upon past project experiences, looks at correlations, which may be useful in predicting outcomes and success rates of future projects. Several case studies are discussed of projects that are in operation or are under the planning/construction phase, and specific lessons learned are highlighted.

To define what is meant by "remote", one should not only refer to a significant geographical distance. There are other factors related to remote projects that cause severe challenges in any or all of the planning, design, construction, operations and export phases, and therefore these need to be incorporated into the concept of the remoteness of a project.

The criteria identifying "**R.E.M.O.T.E**" are as follows:

- **Geographical Remoteness**: This refers to the site being a significant distance from any infrastructure, urban centre and notable logistical availability. Geographical distance from market is not considered in this factor. However, distance from the gas source to the LNG plant is an issue.

- **Extreme Climatic Conditions**: This refers to either constant extreme temperatures, significant seasonal temperature swings, or such adverse constant or varying extreme conditions like snow, wind, rain and humidity. The Köppen-Geiger climate classification is used to define the "E" in remote.

  An example of an LNG plant with extreme climatic conditions is Yamal LNG. The cold and harsh conditions associated with LNG projects in Arctic locations impact the development of onshore LNG facilities, but also the offshore Port and LNG shipping requirements. The Yamal LNG development notably has an ice cover and ice encroachment into the Port area for around 70% of the time of the year, requiring LNG carriers with ice-breaking capacities.

- **Manpower Problems**: Severe operational challenges caused by the lack of skilled affordable manpower, applicable mainly to the construction phase but also relevant to the operational phase.

- **Operational Challenges / Infrastructure**: Access to the site, local content problems through lack of local suppliers – mainly affects the construction phase but has a significant impact on the operational phase as well.

- **Technical Hurdles:** As ever in the oil and gas business, the need for a technical solution drives the development of the technical solution. This criterion rates projects in relation to the technological challenges faced in the design, construction and operational phases. Technical hurdles have been overcome in the past and will change in the future. Therefore, the Remoteness Index needs to be understood in context with time.

- **Environmental Sensitivity**: By default, most remote areas of the world are untouched and considered environmentally sensitive. Any new projects in these areas will inevitably have an effect on the environment and there is increasing public resistance to such intrusions.

Initial developments of the earliest liquefaction plants were ground-breaking in terms of technology application and provided great leaps and bounds regarding know-how. Whilst at the time they were constructed in what were considered out-of-the-way places, today many of the plant locations are considered as standard. So, which plants are more “remote” than the others, what makes them more remote and what does the future hold?

In order to address this, and be able to quantify “remoteness”, the previously mentioned factors can be defined and weighted to provide a numerical indication of remoteness: The Remoteness Index (score of 5 is the maximum on the “remoteness” scale).

When plotting all LNG Plants, operational, under construction and planned versus the Remoteness Index, a statistical distribution with a clear trend can be observed in Figure 9.1.

While the distribution of the Remoteness Index was quite narrow in a band between 3 and 4, which can be nicely fitted with a Gaussian distribution, some new projects, especially in the US do not follow the former trend. This can be explained by the fact that, with successful new production methods like fracking and gas collection from many wells, cheap US shale gas has triggered a series of new projects with surprisingly low Remoteness Indices. The Remoteness Index can be used as an analytical tool to identify trends both historical and future, and allows for an explanation of the historical trends and a potential prediction of the future. The above is one example of many presented in the IGU report on Remote LNG.

Major conclusions presented in the extended IGU report for the criteria defining the Remoteness Index are explored in the following chapters:

9.2. GEOGRAPHICAL AND CLIMATIC CONDITIONS

The Arctic Circle offers perhaps the most prolific potential regarding exploration, but at the same time it presents some of the biggest challenges regarding development and export of gas to market. Cold and harsh conditions present a unique set of technical challenges in all phases of the project, including the export of LNG in carriers with ice-breaking capability.

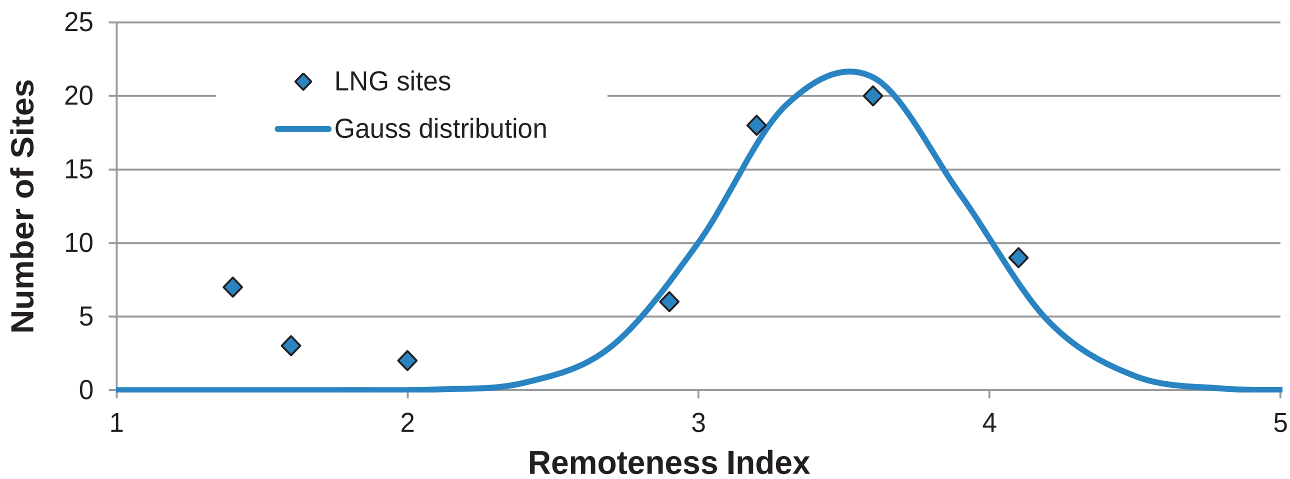


Figure 9.1: Statistical Distribution of the Remoteness Index

Source: IGU

Country	Project	Announced Start Year	Geographical Remoteness	Extreme climatic conditions	Manpower problems	Operational challenges	Technical hurdles	Environmental concerns	Remoteness Index
US	**Alaska LNG**	2023	4	5	4	4	4	5	**4.4**
Indonesia	**Bontang LNG**	1977	4	4	5	4	4	5	**4.3**
PNG	**PNG LNG**	2014	5	4	5	3	2	5	**4.2**
PNG	**Gulf LNG**	2021	5	4	5	3	2	5	**4.2**
Indonesia	**Arun LNG**	1978	4	4	5	4	4	4	**4.1**
Russia	**Yamal LNG**	2020	5	5	4	4	3	3	**4.1**
Indonesia	**Natuna D Alpha**	2025	3	4	4	4	5	5	**4.1**
Indonesia	**Tangguh LNG**	2009	5	4	5	2	2	5	**4**
Indonesia	**Donggi-Senoro LNG**	2014	5	4	5	2	2	5	**4**

Table 9.1: Highly Remote Plants Ordered by Remoteness Index

Source: IGU

Other locations in Asia-Pacific and East Africa are likely hard to reach due to geographical isolation and lack of well-developed infrastructure. Severe climatic conditions affect the design of the project and can significantly influence construction activities. All planning cycles should be carefully matched with adequate contingencies to the weather cycles.

While infrastructure will develop over the years, adverse climatic conditions cannot be changed by mankind. Thus, this aspect will remain a significant indicator for a profitable liquefaction project.

9.3. SOCIAL AND ENVIRONMENTAL ISSUES

The majority of remote projects, even though initially located in areas of little or no urbanisation, do affect the socio-political landscape, often leading to development of urbanisation and bringing significant social change. In addition, the social implications of large-scale investment projects are increasingly an obligation in the design and planning stage. They carry a large social responsibility towards indigenous habitants. Social responsibility programs need to be part of project execution and operation.

Environmental constraints need to be taken into account to minimise the impact on marine and wildlife environment, which has not seen industrial development. While people may assimilate to changes in their social and cultural life within decades, the environment needs much longer periods to recover from imprudent disturbances. A short-sighted run for profit may cause tremendous expenses to re-establish fair living conditions. Thus, a high rating in the category Environmental Concerns needs to be considered seriously when new projects approach FID.

9.4. TECHNICAL AND OPERATIONAL CHALLENGES

All countries, especially the new LNG players, are demanding significant Local Content in projects. Whilst most LNG project shareholders fully support the notion of Local Content, the reality is often a big obstacle in the sanctioning and development of remote projects. Development of these project requirements has a special focus on operation, maintenance, safety and occupational health.

From a design point of view, remote projects have special requirements due to soil conditions, ambient conditions like snow and ice or storms, humidity and sun radiation. This results in selecting optimal liquefaction technology, redundancy of equipment to ensure reliability and sometimes extensive winterisation of structures and equipment.

Proper planning is critical since construction windows may be limited. Standardisation and modularisation to minimise construction work on site is one of the key success factors of constructing remote projects.

Technology is keeping pace with hostile environment project requirements. No project to date has been shelved due purely to the lack of technological solutions, but rather due to the lack of economic viability of the required technological solutions.

9.5. COST IMPACT OF THE REMOTENESS INDEX

While one could expect a certain direct correlation between remoteness (and therefore the Remoteness Index) and LNG project costs, the fact is that we cannot properly infer such a relation looking at past projects. While certain Remoteness criteria clearly do have an impact on a project's overall costs, other factors – such as materials costs, contractors' workload panorama, project confluence and many others – also have a very large impact. A clear correlation between remoteness and cost looks as likely to be as absent for future projects as has been the case up until now.

9.6. USAGE OF THE REMOTENESS INDEX

Nevertheless, the Remoteness Index can be taken as an indication about how challenging a new LNG project can be due to its location; in this sense, new remote project developers can find it useful to check their new project's Remoteness Index estimate against other past projects with similarities.

A full report dedicated to this subject is available on the IGU website: http://igu.org/publications/RemoteLNG.pdf

© Yamal LNG – Alexander Evgrafov

The 16.5 MTPA Yamal LNG project being executed on the Yamal Peninsula (Russian Federation) beyond the Arctic Circle with start-up slated for 2017 (first train), 2018 (second train), and 2019 (third train)

10. Special Report – Life Cycle Assessment of LNG

10.1. INTRODUCTION

The demand for LNG has grown rapidly since the 1980's. This is mainly because of the environmental advantages of natural gas over other fossil fuels in addition to its price competitiveness and energy efficiency. In power generation, for example, coal has always been the traditional fuel due to its availability, cost and ease-of-use. With the emergence of oil in this market, suppliers and buyers tended to favour oil because of its natural state and its ease of handling, transport, and storage. Oil being liquid helps users and suppliers ship it and store it easily. With the advance of natural gas, it became a highly demanded source of energy. This is because it is relatively less expensive and cleaner than other fossil fuels, including oil used for power generation.

However, a full environmental impact accounting for different forms of energy requires a broader context of evaluation than simply measuring the direct pollutant emissions from combustion at the point of use. Air emissions should be accounted for across the value chains for these competing products. Such accounting is especially important when contributions of GHGs are considered. These emissions have not been seen as environmental contaminants until recently. Carbon dioxide (CO_2) emissions from combustion and methane (CH_4) losses released from energy containment systems are principal examples of these "new" emissions concerns. Life cycle assessment (LCA) has become a widely-used approach for evaluating air pollutant emissions across energy value chains. Including both primary energy and secondary energy inputs, LCA provides the most comprehensive and valid approach for environmental impact assessments for air quality.

An extensive report dedicated to this subject has been produced by an IGU study group in 2015 and is available on the IGU website:
http://igu.org/publications/LNGLifeCycleAssessment.pdf

10.2. AIMS

The objective of the study during the last 3 years (2012-2015) was to develop International Standards Organization (ISO)-compliant life cycle inventory (LCI) data to support independent LCAs. The ISO Standard 14040, "Environmental Management – Life Cycle Assessment – Principles and Framework" and Standard 14044 "Environmental Management – Life Cycle Assessment – Requirements and Guidelines" provide the essential requirements for compiling LCI data. LCAs conducted using this study's LCI data would characterise air emissions from LNG operations comprising the LNG value chain. This includes beginning with the receipt of natural gas for liquefaction to delivery of regasified LNG ("regas") for pipeline distribution as natural gas, direct end use, or liquid delivery of LNG directly to end use applications. Air emissions covered include point source and area source emissions of conventionally-regulated air quality pollutants (including particulates, carbon monoxide, oxides of nitrogen) and major GHGs (CO2, CH4, and others). Emissions-related LNG activities addressed include steady-state liquefaction and regas operations, energy transfer operations, storage operations, and onsite and offsite point source electrical and mechanical power supply operations supporting the LNG chain.
LNG chain emissions data is intended to provide the basis

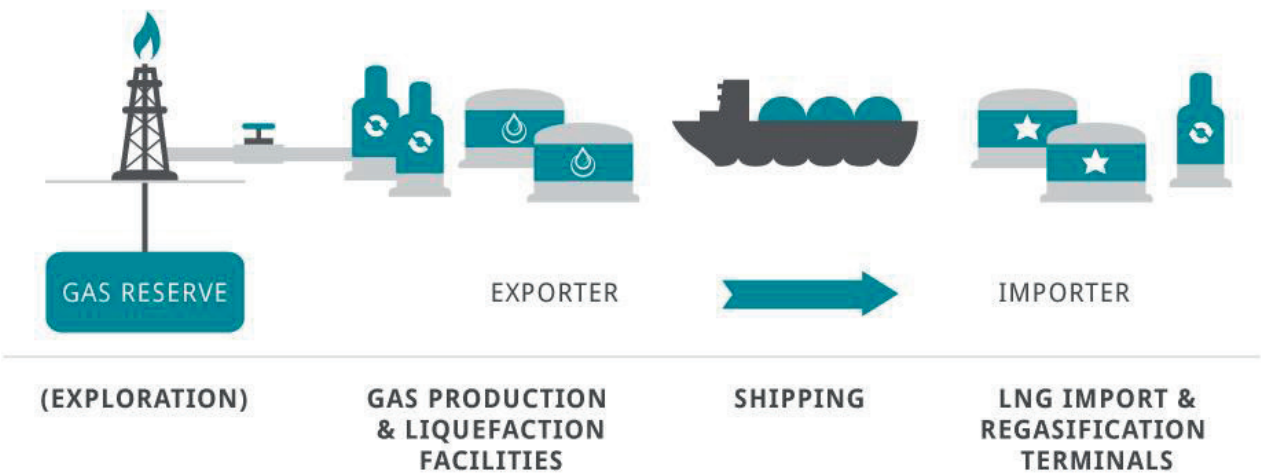


Figure 10.1: The LNG Life Cycle
Source: Goldboro LNG

for comparison to emissions from other competing energy forms. Value chain emissions characterisations also help to identify opportunities for improved performance in air emissions reductions achievable through new technology applications, operational changes and other LNG chain modifications.

LCAs conducted using this study's LCI data may be conducted by industry participants and associations, governmental authorities, non-governmental organisations (NGOs), or individuals.

Also, LCAs ultimately conducted using this study's results may be made publicly available for review and use or retained for private and proprietary use. However, the data developed for LNG chain characterisation in this study is freely available for public use through the IGU report. Digital presentation of the data is ultimately envisioned.

Source: The Oregonian Live

10.3. METHODS

Since all LCAs on LNG are fundamentally limited by definitions of the LNG chains, this project uses a "modular approach" for LCI data development and archive. This approach helps support a range of individual LCAs to serve the broadest definitions of the industry. Independent assembly of LNG LCA modules by independent investigators allows users to represent chains that are directly relevant to their projects and LCA concerns. In the full IGU report, chain coverage has been limited to the following segments:

- Liquefaction, beginning with received feedstock
- LNG transport, focusing on marine carriers, and
- Regas, terminating with plant send out.

Upstream gas supply and downstream natural gas and LNG end uses are not covered because of the complexities of these segments and their coverage in other LCAs to explore specific policy objectives. The consensus of the IGU Study Group is that LNG LCA emissions with respect to liquefaction, LNG transport and regas need to be captured in a reliable, robust and transparent way (that is, "get the LNG chain right" for representing the broader natural gas value chain). Additionally, many other studies have and continue to address upstream and downstream emissions issues, but characterisation of air emissions from the LNG chain elements remains an understudied focus.

Only onshore facilities for liquefaction and regas of large-scale, traded LNG operations are represented. "Retail LNG" such as LNG transfers as vehicle fuel and floating LNG are not addressed. The "product system" for LCA purposes is limited to production, transportation and delivery of primary energy in the form of natural gas in its compositional form (principally as methane). In addition, emissions from primary energy inputs to LNG production, transportation and regas, such as fossil fuel use for onsite and offsite power supply supporting these LNG operations is included. It does not address secondary energy products or co-products of LNG operations that feasibly could be included within LNG facilities and operations.

Stated formally, the product system boundaries (natural gas receipt for liquefaction to delivery of natural gas to pipelines or LNG to end use customers) comprise the linear system boundaries of the LNG chains covered. Emissions from production, transport, construction, commissioning, repair and maintenance, and decommissioning of LNG chain technologies and facilities are outside the system boundaries and are not covered. Emissions from module start-up, shut-down for major maintenance and retirement are outside the system boundaries.

Study Group efforts are heavily supported by contractor data development and compilation efforts of PACE Global (a Siemens Company) under the direct sponsorship of the Center for LNG in the US.

10.4. CASE EXAMPLE

Included in the study group report is an example LCA comparing GHG emissions from natural gas to coal for electric power generation as a "base case." The competing natural gas and coal chains include coverage of LNG liquefaction, transport and regas within the natural gas value chain to competing production, transport and end use of coal in central power stations. LNG chain module data developed for the LCI are used to represent the LNG chain segments of this case study. LNG chain modules covered include natural gas pre-treatment for liquefaction, five major liquefaction technologies served by four compression drive systems and three electric power approaches, four major LNG marine carrier designs and propulsion systems, and four major regas technologies served by three electric power approaches. GHG emission performance for the natural gas chain (and individual LNG chain alternatives) is compared to that of the coal base case. In all combinations of LNG chain modules represented for natural gas, the superior performance of natural gas to coal in terms of GHG emissions is demonstrated.

10.5. RESULTS

Results of the IGU study focus on LCI data development serve a broader range of uses than the comparison made in the case study. Part One of the IGU Study Group Report provides background information on natural gas as a sustainable, environmentally-beneficial primary energy source and background information on the role and implementation of LCAs. Results of the LCI data development are fully documented in text and tabular form in the Part Two of the report. In addition to the Study Group report, it is intended that data will be provided in digital form for use in subsequent LCA and environmental studies.

As an illustration of data developed for the LCI, Table 10.1 presents a summary of CO_2 emission rates calculated for selected liquefaction processes from one data source.

10.6. CONCLUSIONS

Conclusions of the Study Group work can be captured in the following points:

- Practical application of the LCI data within full LCAs is the principal means of realising the benefits of this study. It is envisioned that continuing IGU studies under its "Sustainability" focus may employ this data to its full extent. However, public availability of the data to the broader LCA community can assist IGU in contributing to more broadly address environmental and sustainability objectives.

- Documentation of LCI data highlights the need for broader primary data development for air emissions from the LNG value chain and the need to extend data development beyond steady-state LNG operations.

- Full implementation of LCA requires going beyond primary air emissions, which has been the focus of most LCAs covering LNG to date, and addressing water, solid waste and land use issues.

- Focus on maintaining maximum transparency and objectivity is highlighted by the ISO standards reporting and documentation approach. Only through the use of such tools and their essential requirements can consensus on emissions from the LNG value chain be achieved.

- LCI data, including its use in complete LCAs, can be used for "technology roadmap" development for reducing emissions within LNG chains and should be employed to that end.

- Competing energy forms need to be similarly quantified and documented for reasonable and justifiable comparisons of energy chains to natural gas generally and LNG specifically. It is envisioned that this study will prompt similar efforts to competing fuels so that consistent comparisons of life cycle impacts can be conducted.

Liquefaction Cycle CO_2 **(Partial List)**	Single Mixed Refrigerant	Nitrogen Expander	C3 Mixed Refrigerant Aeroderivative/ Waste Heat Recovery	C3 Mixed Refrigerant Aeroderivative/No Waste Heat Recovery	C3 Mixed Refrigerant Combined Cycle/Waste Heat Recovery	C3 Mixed Refrigerant/ Electric Drive
Total CO_2 (kg/ton LNG)	88	84	89	89	93	88
Pre-treatment Heat (kg/hr)	0	0	0	0	0	0
Pre-treatment Power (kg/hr)	5,851	5,851	15,268	15,277	15,215	15,282
Liquefaction Heat (kg/hr)	0	0	0	0	0	0
Liquefaction Power (kg/hr)	144,187	201,267	115,591	115,229	65,726	139,732
Auxiliary Power (kg/hr)	0	0	0	4,738	0	0
Total to Atmosphere (kg/hr)*	181,058	238,316	161,880	176,130	111,963	186,035
Total to Reinjection (kg/hr)	0	0	0	0	0	0

Table 10.1: CO_2 Emission Rates for Selected Liquefaction Processes

**Includes other sources not detailed in the table.*

Sources: IGU; Statoil, Marak, et al.

11. The LNG Industry in Years Ahead

What will LNG prices do in 2015?

Oil price volatility is one of the most important factors impacting the LNG market in 2015. With Brent prices falling to under $50/bbl in January 2015, down from over $100/bbl in August 2014, LNG prices for oil-linked term contracts are set to fall sharply. Most long-term LNG contracts are priced with a lag against oil, on average by four months, meaning that these LNG supplies were priced at a premium to oil in early 2015. Absent a further fall in oil prices, LNG will come back into merit relative to oil thereafter, though future oil price volatility could lead to wide swings in the price of term LNG supplies. New Pacific Basin LNG supplies set to enter the market in 2015 could further impact LNG prices. However, a prolonged outage at existing projects could potentially offset these supply additions, leaving the market without any trade growth for the year and staving off major spot price trajectory changes. The temporary force majeure at Yemen LNG and shut-down of Snøhvit LNG in January 2015 acted as a reminder that such outages could materialise in 2015. Conversely, Angola LNG will eventually bring cargoes to a market which is already very well-supplied.

How will LNG prices affect demand?

Major deviations in LNG demand trajectories for most importers are not likely to occur in 2015. Although LNG prices will fall as a result of the oil price decline, energy users also benefit from other supply sources becoming more competitive. For instance, Europe and China buy pipeline gas on an oil-linked basis. In the near-term, though, users with the ability to fuel-switch in power and industry – but are not competing with oil – may stand to benefit. However, major gains in the power sector are likely to be offset by weak prices in international seaborne coal in 2015. For LNG to make a step-change in consumption, LNG prices would need to dip to extremely low price levels in 2015. A positive note on demand will come from new buyers having decided to go for FSRU investments like Egypt, Jordan, Pakistan, Poland and others.

How will cross-basin trade evolve?

The onset of new Australian projects in 2015 (QCLNG and GLNG) and the first full year of production from PNG LNG could displace some Atlantic and Middle Eastern cargoes that might have otherwise gone to the Pacific Basin. Despite the weak gas demand environment in Europe, its flexible and liquid traded markets will be able to accommodate additional volumes, in the most part by displacing alternative pipeline supply, particularly from flexible volume legacy supply contracts. A weak gas price environment coupled with planned increases in the carbon price in the UK point to some upside for demand in the British power sector. With falling LNG prices, the price differential between Atlantic and Pacific markets is also decreasing, making exports from Atlantic Basin producers or re-exports less attractive and keeping more LNG within the Atlantic Basin, and within Europe in particular. Qatar is well located to play the arbitrage between basins and 2015 will probably be a year for European terminals receiving more and more cargoes from Qatar.

How will China and India respond to the changing LNG price environment?

China is by far the fastest growing natural gas import market in absolute terms and plays an increasingly important role for flows in the global LNG market. In 2015, China is set to see the largest incremental LNG import growth of any country based on imports under new long-term supply contracts. However, even as smaller players in China's domestic gas market enter the spot market, the lower LNG price environment will unlikely have a major impact on Chinese spot LNG activity. The price differential with alternative energy prices is the main factor guiding spot demand. The fall in oil prices has reduced the price differential between spot LNG and oil, making additional fuel substitution across all demand sectors less attractive. A sharp demand response would likely only materialise if LNG prices fell closer to the coal-to-gas switching point, typically around $6/mmBtu, which would require even further LNG price deterioration. However, the 2015 LNG spot price environment bodes well for opportunistic buyers such as India. As domestic production trends downward, India will likely continue to supplement contracted LNG with spot and short-term volumes to meet demand, and benefit from any downward pressure on prices.

How will Japan and South Korea's demand evolve in 2015?

Japan and South Korea functioned in the past as the engine for global LNG demand growth, but the engine started to stutter in 2014. While Japanese imports rose by just over 1 MT, South Korean LNG demand fell by 2.8 MT, leading combined imports to decline by 1.7 MT. This trend will likely continue in 2015, with expected limited LNG demand growth in South Korea and a likely decline in Japan. Temperatures in both countries are expected to be at above normal levels for the 2014/15 winter season providing no extra boost to heating demand. Both countries should see increasing nuclear power generation in 2015 from nuclear capacity coming online. South Korea could see one new reactor starting commercial operations in the third quarter of 2015 after an operating license was given in November 2014, and a potential second one could start-up in the fourth quarter, backing out other sources of power generation. In Japan, the restart of nuclear reactors faces still significant uncertainties, but four reactors had received regulatory approval by the beginning of 2015. Taking additional regulatory and political hurdles into account, it is unlikely that the first Japanese reactor will restart commercial operations before mid-2015.

How much CBM-to-LNG will be produced from the new Queensland projects in Australia?

Projects in Queensland will be the largest source of new LNG supply in 2015. QCLNG T1 delivered its first cargo in January 2015, and QCLNG T2, GLNG T1 and APLNG T1-2 are all announced to come online later in 2015. Overall, these three trains will add 17.2 MTPA of new capacity. However, variability in production is a major unknown with hundreds of wells to be drilled in 2015. The CBM operators have been ramping up gas production for several years now (selling gas to the domestic market), but their operational performance has yet to be tested. The projects have some un-contracted capacity offering them a degree of production flexibility. In a loosening market, this may be opportune to produce at lower levels since prices will be suppressed.

Will additional liquefaction projects reach FID in 2015?

The high level of sanctioning activity that has occurred in the past four years is unlikely to continue into 2015. Falling oil prices and correspondingly weakening LNG prices have led many project proponents to take a step back at the beginning of the year. With CAPEX spending increasingly being reduced across the board, many high-cost LNG projects are likely to be delayed. Though financing is expected to become more challenging in the low oil price environment, inadequate returns are more likely to prompt project delays or cancelations than the sponsors' inability to raise enough debt. This is notably true for projects in frontier regions such as Western Canada and East Africa. The best candidates to reach FID in 2015 are located in the US. Freeport T3 and Corpus Christi LNG T1-2 are particularly strong contenders as both are at an advanced stage of LNG marketing.

What are the trends in contract patterns?

In recent years, a number of LNG buyers have turned to Henry Hub-indexed US LNG as an alternative to traditional oil-linked LNG contracts. In a lower oil price environment, however, the attractiveness of US LNG will erode. Buyers may be less pre-occupied with the price and portfolio diversity that US LNG provides when oil-indexed contracts are more competitive. This could lead to a prolonged

The PETRONAS FLNG1 is approaching construction completion and is expected to commence production in 2016 hiatus in LNG contracting activity for incremental volumes from US projects. Indeed, only one US LNG contract has been signed since August 2014. Rather than a slate of new US LNG signings, the market could see expiring contracts from existing projects extended. Alternatively, under-contracted volumes from under construction projects could be signed. Projects under construction globally have around 20 MTPA of un-contracted supply available in 2020. Angola LNG has yet to be marketed on a long-term basis and alone accounts for 5.2 MTPA of available capacity. Further, LNG buyers may increasingly seek to move away from traditional, fixed, long-term contracts, turning instead to short-term or medium term supply deals with a higher degree of volume and/or destination flexibility.

How will FLNG affect the LNG industry?

The first FLNG plants are set to enter the market over the coming years. PETRONAS' PFLNG 1 (1.2 MTPA) plant in Malaysia is one of the most advanced projects. Other projects under construction include PETRONAS' PFLNG 2 (1.5 MT) plant in Malaysia and Shell's highly anticipated 3.6 MTPA Prelude FLNG project in Australia. A further 43 MTPA of floating capacity has been proposed to come online by 2020. Certain independent shipping companies have been active in pushing for FLNG, ordering several LNG carriers to be converted into floating units and seeking to place these vessels globally. Should the technology prove successful, FLNG may become increasingly sought after as a flexible and cost-effective solution to market gas reserves, particularly from smaller, stranded offshore fields without viable alternative commercialisation options. In the near-term, however, falling oil prices and global market conditions will likely slow the momentum for FLNG project development. The first glimpses of this dynamic emerged in late 2014 when development of the 8 MTPA FLNG project in Lavaca Bay, Texas was put on hold. In early 2015, the start-up of Caribbean FLNG (0.53 MTPA) – previously expected to be the first floating project to enter the market – was also pushed back.

Will charter rates stay low and for how long?

2014 marked the start of the next surplus in LNG shipping capacity. Estimated average monthly charter rates fell as low as ~$40,000/day in the third quarter of 2014 as demand for Atlantic Basin volumes in the Pacific Basin weakened and the number of long-distance cross-basin voyages declined. Spot charter rates recovered to an average of around $55,000/day by the end of 2014, though speculative newbuilds expected to be delivered into the market in the first half of 2015 will further push the LNG shipping market into oversupply. 2015 will see insufficient growth in new liquefaction capacity to absorb the new vessels. The capacity surplus is likely to continue over the next three years until significant new liquefaction capacity ramps up in Australia and the US.

Alpha Platform Operating on North Field at Sunset

12. References Used in the 2015 Edition

12.1. DATA COLLECTION

Data in the 2015 World LNG Report is sourced from a variety of public and private domains, including the BP Statistical Review of World Energy, Cedigaz, the International Energy Agency (IEA), the Oxford Institute for Energy Studies (OIES), the US Energy Information Agency (EIA), the US Department of Energy (DOE), GIIGNL, IHS, company reports and announcements. This report should be read in conjunction with the 2013 and 2014 World LNG Reports, available on the IGU website at http://www.igu.org/publications.

The data and associated comments have been reviewed and verified by IGU.

The IGU wishes to thank the following organisations for providing their expert staff to be a member of the Task Force which has been entrusted to oversee the preparation and publication of this report:

TOTAL, France	SIGTTO, UK
American Gas Association (AGA), USA	PETRONAS, Malaysia
Dourogás, Portugal	Qatargas, Qatar
GIIGNL, France	RasGas, Qatar
Indian Oil Corp Ltd., India	Vopak, Netherlands

IGU also wishes to thank the four PGCD working groups that provided the Special Report summaries.

12.2. DEFINITIONS

Brownfield Liquefaction Project: A land-based LNG project at a site with existing LNG infrastructure, including but not limited to storage tanks, liquefaction facilities and regasification facilities.

Forecasted Data: Forecasted liquefaction and regasification capacity data only takes into account existing and under construction capacity (criteria being FID taken), and is based on company announced start dates.

Greenfield Liquefaction Project: A land-based LNG project at a site where no previous LNG infrastructure has been developed.

Large-Scale vs. Small-Scale LNG: IGU defines the large-scale LNG industry as every LNG business above 1 MTPA of LNG production and/or consumption. Conversely, small-scale LNG is any business under 1 MTPA.

Liquefaction and Regasification Capacity: Unless otherwise noted, liquefaction and regasification capacity throughout the document refers to nominal capacity. It must be noted that re-loading and storage activity can significantly reduce the effective capacity available for regasification.

LNG Carriers: For the purposes of this report, only Q-Class and conventional LNG vessels with a capacity greater than 30,000 cm are considered part of the global fleet discussed in the “LNG Carriers” chapter (Chapter 5). Vessels with a capacity of under 30,000 cm are considered small-scale LNG carriers.

Northeast Asian Spot Prices: Northeast Asian spot prices are calculated based on the observed average price for spot cargoes imported into Japan and South Korea in a given month.

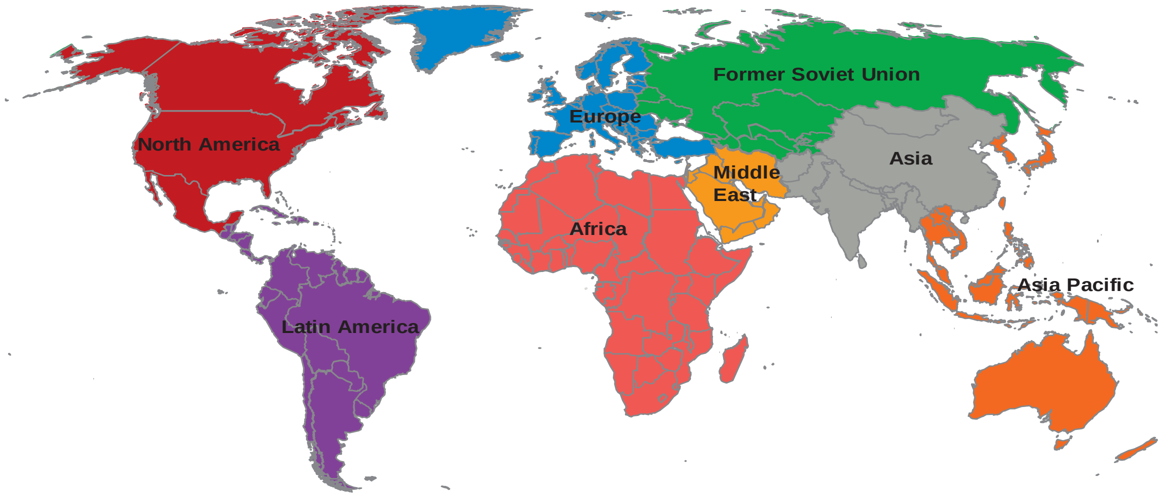
Project CAPEX: Liquefaction plant CAPEX figures reflect the complete cost of building the facilities, including site preparation, gas processing, liquefaction, LNG storage and other related infrastructure costs. Regasification terminal CAPEX figures are based on company announcements and may therefore only include selected infrastructure components.

Spot and Short-term, Medium-term and Long-term Trade:

- Spot and short-term trade = volumes traded on a spot basis or under contracts of less than 2 years
- Medium-term trade = volumes traded under a 2 to <5 year contract
- Long-term trade = volumes traded under a 5+ year contract

Traded LNG Volumes: Trade figures are measured according to the volume of LNG imported at the regasification level. Only international trade is taken into account. Domestic LNG trade in Indonesia is thus excluded from the global figures.

12.3. REGIONS AND BASINS



The IGU regions referred to throughout the report are defined as per the colour coded areas in the map above. The report also refers to three basins: **Atlantic**, **Pacific** and **Middle East**. While the Atlantic Basin encompasses all countries that border the Atlantic Ocean or Mediterranean Sea, the Pacific Basin refers to all countries bordering the Pacific Ocean. However, these two categories do not include the following countries, which have been differentiated to compose the Middle East Basin: Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Oman, Qatar, UAE and Yemen. IGU has also taken into account countries with liquefaction or regasification activities in multiple basins and has adjusted the data accordingly.

12.4. ACRONYMS

BOG = Boil-Off Gas
BOR = Boil-Off Rate
CBM = Coalbed methane
DFDE = Dual-Fuel Diesel Electric LNG vessel
EPC = Engineering, Procurement and Construction
FEED = Front-End Engineering and Design
FERC = Federal Energy Regulatory Commission
FID = Final Investment Decision
FOB = Free On Board
FTA = Free-Trade Agreement
FLNG = Floating Liquefaction
FSRU = Floating Storage and Regasification Unit
FSU = Former Soviet Union
GHG = Greenhouse gas
ISO = International Standards Organization
LCA = Life Cycle Assessment
LCI = Life Cycle Inventory
ME-GI = M-type, Electronically Controlled, Gas Injection
PCA = Panama Canal Authority
PNG = Papua New Guinea
SPA = Sales and Purchase Agreement
SSD = Slow Speed Diesel
SSLNG = Small-scale LNG
TFDE = Tri-Fuel Diesel Electric LNG vessel
UAE = United Arab Emirates
UK = United Kingdom
US = United States
US DOE = US Department of Energy
US Lower 48 = United States excluding Alaska and Hawaii
YOY = Year-on-Year

12.5. UNITS

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

12.6. CONVERSION FACTORS

Multiply by

	Tonnes LNG	cm LNG	cm gas	cf gas	mmBtu	boe
Tonnes LNG		2.222	1,300	45,909	53.38	9.203
cm LNG	0.450		585	20,659	24.02	4.141
cm gas	7.692×10^{-4}	0.0017		35.31	0.0411	0.0071
cf gas	2.178×10^{-5}	4.8×10^{-5}	0.0283		0.0012	2.005×10^{-4}
mmBtu	0.0187	0.0416	24.36	860.1		0.1724
boe	0.1087	0.2415	141.3	4,989	5.8	

Appendix I: Table of Global Liquefaction Plants

Reference Number	Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
1	US	Kenai LNG**	1969	1.5	ConocoPhillips	ConocoPhillips Optimized Cascade®
2	Libya	Marsa El Brega***	1970	3.2	LNOC	APC C_3MR
3	Algeria	Skikda - GL1K (T1-4)	1972	1	Sonatrach	Teal (T1-3), PRICO (T4)
4	Brunei	Brunei LNG T1-5	1972	7.2	Government of Brunei, Shell, Mitsubishi	APC C_3MR
5	Indonesia	Bontang LNG T1-2	1977	5.4	Pertamina	APC C_3MR
6	United Arab Emirates	ADGAS LNG T1-2	1977	2.6	ADNOC, Mitsui, BP, TOTAL	APC C_3MR
3	Algeria	Arzew - GL1Z (T1-6)	1978	6.6	Sonatrach	APC C_3MR
5	Indonesia	Arun LNG T1****	1978	1.65	Pertamina	APC C_3MR
3	Algeria	Arzew - GL2Z (T1-6)	1981	8.2	Sonatrach	APC C_3MR
3	Algeria	Skikda - GL2K (T5-6)	1981	2.2	Sonatrach	PRICO
5	Indonesia	Bontang LNG T3-4	1983	5.4	Pertamina	APC C_3MR
8	Malaysia	MLNG Satu (T1-3)	1983	8.1	PETRONAS, Mitsubishi, Sarawak State government	APC C_3MR
7	Indonesia	Arun LNG T6****	1986	2.5	Pertamina	APC C_3MR
9	Australia	North West Shelf T1	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
9	Australia	North West Shelf T2	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
5	Indonesia	Bontang LNG T5	1989	2.9	Pertamina	APC C_3MR
9	Australia	North West Shelf T3	1992	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
5	Indonesia	Bontang LNG T6	1994	2.9	Pertamina	APC C_3MR
6	United Arab Emirates	ADGAS LNG T3	1994	3.2	ADNOC, Mitsui, BP, TOTAL	APC C_3MR
8	Malaysia	MLNG Dua (T1-3)	1995	7.8	PETRONAS, Shell, Mitsubishi, Sarawak State government	APC C_3MR
10	Qatar	Qatargas I (T1)	1997	3.2	Qatar Petroleum, ExxonMobil, TOTAL,, Marubeni, Mitsui	APC C_3MR
10	Qatar	Qatargas I (T2)	1997	3.2	Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui	APC C_3MR
5	Indonesia	Bontang LNG T7	1998	2.7	Pertamina	APC C_3MR
10	Qatar	Qatargas I (T3)	1998	3.1	Qatar Petroleum, ExxonMobil, TOTAL, Mitsui, Marubeni	APC C_3MR
5	Indonesia	Bontang LNG T8	1999	3	Pertamina	APC C_3MR
11	Nigeria	NLNG T1	1999	3.3	NNPC, Shell, TOTAL, Eni	APC C_3MR
10	Qatar	RasGas I (T1)	1999	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	APC C_3MR
12	Trinidad	ALNG T1	1999	3.3	BP, BG, Shell, CIC, NGC Trinidad	ConocoPhillips Optimized Cascade®
11	Nigeria	NLNG T2	2000	3.3	NNPC, Shell, TOTAL, Eni	APC C_3MR
13	Oman	Oman LNG T1	2000	3.55	Omani Govt, Shell, TOTAL, Korea LNG, Partex, Mitsubishi, Mitsui, Itochu	APC C_3MR
13	Oman	Oman LNG T2	2000	3.55	Omani Govt, Shell, TOTAL, Korea LNG, Partex, Mitsubishi, Mitsui, Itochu	APC C_3MR
10	Qatar	RasGas I (T2)	2000	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	APC C_3MR
11	Nigeria	NLNG T3	2002	3	NNPC, Shell, TOTAL, Eni	APC C_3MR
12	Trinidad	ALNG T2	2002	3.5	BP, BG, Shell	ConocoPhillips Optimized Cascade®

8	Malaysia	MLNG Tiga (T1-2)	2003	6.8	PETRONAS, Shell, Nippon, Sarawak State government, Mitsubishi	APC C_3MR
12	Trinidad	ALNG T3	2003	3.5	BP, BG, Shell	ConocoPhillips Optimized Cascade®
9	Australia	North West Shelf T4	2004	4.4	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
10	Qatar	RasGas II (T1)	2004	4.7	Qatar Petroleum, ExxonMobil	APC C_3MR/ Split MR™
14	Egypt	ELNG T1***	2005	3.6	BG, PETRONAS, EGAS, EGPC, GDF SUEZ	ConocoPhillips Optimized Cascade®
14	Egypt	ELNG T2***	2005	3.6	BG, PETRONAS, EGAS, EGPC	ConocoPhillips Optimized Cascade®
14	Egypt	Damietta LNG T1***	2005	5	Gas Natural Fenosa, Eni, EGPC, EGAS	APC C_3MR/ Split MR™
10	Qatar	RasGas II (T2)	2005	4.7	Qatar Petroleum, ExxonMobil	APC C_3MR/ Split MR™
15	Australia	Darwin LNG T1	2006	3.6	ConocoPhillips, Santos, INPEX, Eni, TEPCO, Tokyo Gas	ConocoPhillips Optimized Cascade®
11	Nigeria	NLNG T4	2006	4.1	NNPC, Shell, TOTAL, Eni	APC C_3MR
11	Nigeria	NLNG T5	2006	4.1	NNPC, Shell, TOTAL, Eni	APC C_3MR
10	Oman	Qalhat LNG	2006	3.55	Omani Govt, Oman LNG, Union Fenosa Gas, Itochu, Mitsubishi, Osaka Gas	APC C_3MR
12	Trinidad	ALNG T4	2006	5.2	BP, BG, Shell, NGC Trinidad	ConocoPhillips Optimized Cascade®
16	Equatorial Guinea	EG LNG T1	2007	3.7	Marathon, Sonagas, Mitsui, Marubeni	ConocoPhillips Optimized Cascade®
17	Norway	Snøhvit LNG T1	2007	4.2	Statoil, Petoro, TOTAL, GDF SUEZ, RWE	Linde MFC
10	Qatar	RasGas II (T3)	2007	4.7	Qatar Petroleum, ExxonMobil	APC C_3MR/ Split MR™
9	Australia	North West Shelf T5	2008	4.4	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
11	Nigeria	NLNG T6	2008	4.1	NNPC, Shell, TOTAL, Eni	APC C_3MR
18	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™
18	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™
10	Qatar	Qatargas II (T1)	2009	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
10	Qatar	Qatargas II (T2)	2009	7.8	Qatar Petroleum, ExxonMobil, TOTAL	APC AP-X
10	Qatar	RasGas III (T1)	2009	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
19	Russia	Sakhalin 2 (T1)	2009	4.8	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
19	Russia	Sakhalin 2 (T2)	2009	4.8	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
20	Yemen	Yemen LNG T1	2009	3.35	TOTAL, Hunt Oil, Yemen Gas Co., SK Corp, KOGAS, GASSP, Hyundai	APC C_3MR/ Split MR™
8	Malaysia	MLNG Dua Debottleneck	2010	1.2	PETRONAS, Shell, Mitsubishi, Sarawak State government	APC C_3MR
21	Peru	Peru LNG	2010	4.45	Hunt Oil, Shell, SK Corp, Marubeni	APC C_3MR/ Split MR™
10	Qatar	Qatargas III	2010	7.8	Qatar Petroleum, ConocoPhillips, Mitsui	APC AP-X
10	Qatar	RasGas III (T2)	2010	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
20	Yemen	Yemen LNG T2	2010	3.35	TOTAL, Hunt Oil, Yemen Gas Co., SK Corp, KOGAS, GASSP, Hyundai	APC C_3MR/ Split MR™
10	Qatar	Qatargas IV	2011	7.8	Qatar Petroleum, Shell	APC AP-X
22	Australia	Pluto LNG T1	2012	4.3	Woodside, Kansai Electric, Tokyo Gas	Shell propane pre-cooled mixed refrigerant design
2	Algeria	Skikda - GL1K Rebuild	2013	4.5	Sonatrach	APC C_3MR
23	Angola	Angola LNG T1	2013	5.2	Chevron, Sonangol, BP, Eni, TOTAL	ConocoPhillips Optimized Cascade®

24	Papua New Guinea	PNG LNG T1	2014	3.5	ExxonMobil, Oil Search, Govt. of PNG, Santos, Nippon Oil, PNG Landowners (MRDC), Marubeni, Petromin PNG
24	Papua New Guinea	PNG LNG T2	2014	3.5	ExxonMobil, Oil Search, Govt. of PNG, Santos, JX Nippon Oil & Energy, MRDC, Marubeni, Petromin PNG
3	Algeria	Arzew - GL3Z (Gassi Touil)	2014	4.7	Sonatrach
25	Australia	QCLNG T1	2014	4.3	BG, CNOOC

Sources: IHS, Company Announcements

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

*** Kenai temporarily resumed operations in 2014 under a two-year production license, but the plant scheduled to be decommissioned in 2016.*

**** Damietta LNG in Egypt has not operated since the end of 2012; operations at Egyptian LNG have been greatly reduced since the start of 2014. The Marsa El Brega plant in Libya is included for reference although it has not been operational since 2011.*

***** Arun LNG was decommissioned in late 2014. The facility was converted to a regasification terminal.*

APPENDIX II: Table of Liquefaction Plants Under Construction

Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*
Australia	APLNG T1	2015	4.5	ConocoPhillips, Origin Energy, Sinopec
Australia	APLNG T2	2015	4.5	ConocoPhillips, Origin Energy, Sinopec
Australia	GLNG T1	2015	3.9	Santos, PETRONAS, TOTAL, KOGAS
Australia	Gorgon LNG T1-2	2015	10.4	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric
Australia	QCLNG T2	2015	4.3	BG, Tokyo Gas
Colombia	Caribbean FLNG	2015	0.5	Exmar
Indonesia	Donggi-Senoro LNG	2015	2	Mitsubishi, Pertamina, KOGAS, Medco
Malaysia	MLNG 9	2015	3.6	PETRONAS
Malaysia	PFLNG 1	2016	1.2	PETRONAS
Australia	GLNG T2	2016	3.9	Santos, PETRONAS, TOTAL, KOGAS
Australia	Gorgon LNG T3	2016	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric
Australia	Ichthys LNG T1	2016	4.2	INPEX, TOTAL, Tokyo Gas, CPC, Osaka Gas, Chubu Electric, Toho Gas
US	Sabine Pass T1-2	2016	9.0	Cheniere
Australia	Wheatstone LNG T1	2016	4.5	Chevron, Apache, Pan Pacific Energy, KUFPEC, Shell, Kyushu Electric
Australia	Ichthys LNG T2	2017	4.2	INPEX, TOTAL, Tokyo Gas, CPC, Osaka Gas, Chubu Electric, Toho Gas
Australia	Prelude FLNG	2017	3.6	Shell, INPEX, KOGAS, CPC
Australia	Wheatstone LNG T2	2017	4.5	Chevron, Apache, Pan Pacific Energy, KUFPEC, Shell, Kyushu Electric
Russia	Yamal LNG T1	2017	5.5	Novatek, TOTAL, CNPC
US	Cove Point LNG	2017	5.25	Dominion
US	Sabine Pass T3-4	2017	9.0	Cheniere
Malaysia	PFLNG 2	2018	1.5	PETRONAS, MISC, Murphy Oil
Russia	Yamal LNG T2	2018	5.5	Novatek, TOTAL, CNPC
US	Cameron LNG T1-3	2018	12.0	Sempra, Mitsubishi/NYK JV, Mitsui, GDF SUEZ
US	Freeport LNG T1	2018	4.4	Freeport LNG, Osaka Gas, Chubu Electric
Russia	Yamal LNG T3	2019	5.5	Novatek, TOTAL, CNPC
US	Freeport LNG T2	2019	4.4	Freeport LNG, IFM Investors

Sources: IHS, Company Announcements

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

APPENDIX III: Table of LNG Receiving Terminals

Reference Number	Country	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
1	Spain	Barcelona	1969	12.4	ENAGAS 100%	Onshore
2	Japan	Negishi	1969	12	TEPCO 50%; Tokyo Gas 50%	Onshore
3	US	Everett	1971	5.4	GDF SUEZ 100%	Onshore
4	Italy	Panigaglia (La Spezia)	1971	2.5	Eni 100%	Onshore
5	France	Fos Tonkin	1972	4	GDF SUEZ 100%	Onshore
6	Japan	Senboku	1972	15.3	Osaka Gas 100%	Onshore
7	Japan	Sodegaura	1973	29.4	TEPCO 50%; Tokyo Gas 50%	Onshore
8	Japan	Chita LNG Joint/ Chita Kyodo	1977	8	Chubu Electric 50%; Toho Gas 50%	Onshore
9	Japan	Tobata	1977	6.8	Kitakyushu LNG 100%	Onshore
10	US	Cove Point	1978	11	Dominion 100%	Onshore
11	US	Elba Island	1978	12.4	KM LNG Operating Partnership 100%	Onshore
12	Japan	Himeji	1979	13.3	Osaka Gas 100%	Onshore
13	France	Montoir-de-Bretagne	1980	7.3	GDF SUEZ 100%	Onshore
14	US	Lake Charles	1982	17.3	Southern Union 75%; AIG Highstar (Private Equity) 25%	Onshore
15	Japan	Chita	1983	12	Chubu Electric 50%; Toho Gas 50%	Onshore
16	Japan	Higashi-Ohgishima	1984	14.7	TEPCO 100%	Onshore
17	Japan	Nihonkai (Niigata)	1984	8.9	Nihonkai LNG 58.1%; Tohoku Electric 41.9%	Onshore
18	Japan	Futtsu	1985	16	TEPCO 100%	Onshore
19	South Korea	Pyeong-Taek	1986	34.5	KOGAS 100%	Onshore
20	Japan	Yokkaichi LNG Works	1987	7.1	Chubu Electric 100%	Onshore
21	Belgium	Zeebrugge	1987	6.6	Publigas 89.97%; Fluxys 10.03%	Onshore
22	Spain	Huelva	1988	8.4	ENAGAS 100%	Onshore
23	Spain	Cartagena	1989	7.6	ENAGAS 100%	Onshore
24	Japan	Oita	1990	5.1	Kyushu Electric 100%	Onshore
25	Japan	Yanai	1990	2.4	Chugoku Electric 100%	Onshore
26	Taiwan	Yong an (Kaohsiung)	1990	10	CPC 100%	Onshore
27	Turkey	Marmara Ereglisi	1994	5.9	Botas 100%	Onshore
28	South Korea	Incheon	1996	38	KOGAS 100%	Onshore
29	Japan	Sodeshi/Shimizu LNG	1996	1.6	Shizuoka Gas 65%; TonenGeneral 35%	Onshore
30	Japan	Kawagoe	1997	7.7	Chubu Electric 100%	Onshore
31	Japan	Ohgishima	1998	6.7	Tokyo Gas 100%	Onshore
32	Puerto Rico	Peñuelas (EcoElectrica)	2000	1.2	Gas Natural Fenosa 47.5%; International Power 25%; Mitsui 25%; GE Capital 2.5%	Onshore
33	Greece	Revithoussa	2000	3.3	DEPA 100%	Onshore
34	Japan	Chita Midorihama Works	2001	8.3	Toho Gas 100%	Onshore
35	South Korea	Tong-Yeong	2002	17	KOGAS 100%	Onshore
36	Dominican Republic	AES Andrés	2003	1.9	AES 100%	Onshore
37	Spain	Bilbao (BBG)	2003	5.1	ENAGAS 40%; EVE 30%; RREEF Infrastructure 30%	Onshore
38	India	Dahej LNG	2004	10	Petronet LNG 100%	Onshore
39	Portugal	Sines LNG	2004	5.8	REN 100%	Onshore

40	UK	Grain LNG	2005	15	National Grid Transco 100%	Onshore
41	South Korea	Gwangyang	2005	1.8	Posco 100%	Onshore
42	India	Hazira LNG	2005	5	Shell 74%; TOTAL 26%	Onshore
43	Japan	Sakai	2005	2	Kansai Electric 70%; Cosmo Oil 12.5%; Iwatani 12.5%; Ube Industries 5%	Onshore
44	Turkey	Aliaga LNG	2006	4.4	Egegaz 100%	Onshore
45	Mexico	Altamira LNG	2006	5.4	Vopak 60%; ENAGAS 40%	Onshore
46	China	Guangdong Dapeng LNG I	2006	6.7	Local companies 37%; CNOOC 33%; BP 30%	Onshore
47	Japan	Mizushima LNG	2006	1.7	Chugoku Electric 50%; JX Nippon Oil & Energy 50%	Onshore
48	Spain	Saggas (Sagunto)	2006	6.9	RREEF Infrastructure 30%; Eni 21.25%; Gas Natural Fenosa 21.25%; Osaka Gas 20%; Oman Oil 7.5%	Onshore
49	Spain	Mugardos LNG (El Ferrol)	2007	2.6	Grupo Tojeiro 36.5%; Gas Natural Fenosa 21%; Comunidad Autonoma de Galicia 17.5%; Other Companies 15%; Sonatrach 10%	Onshore
50	UK	Teesside GasPort	2007	3	Excelerate Energy 100%	Floating
51	Mexico	Costa Azul	2008	7.5	Sempra 100%	Onshore
52	US	Freeport LNG	2008	11.3	Michael S Smith Cos 45%; ZHA FLNG Purchaser 30%; Dow Chemical 15%; Osaka Gas 10%	Onshore
53	China	Fujian (Putian)	2008	5	CNOOC 60%; Fujian Investment and Development Co 40%	Onshore
54	US	Northeast Gateway	2008	3	Excelerate Energy 100%	Floating
55	US	Sabine Pass	2008	30.2	Cheniere Energy 100%	Onshore
56	Argentina	Bahia Blanca GasPort	2008	3.8	YPF 100%	Floating
57	Italy	Adriatic LNG/Rovigo	2009	5.8	ExxonMobil 46.35%; Qatar Petroleum 46.35%; Edison 7.3%	Offshore
58	US	Cameron LNG	2009	11.3	Sempra 50.2%; GDF SUEZ 16.6%; Mitsubishi 16.6%; Mitsui 16.6%	Onshore
59	Canada	Canaport	2009	7.5	Repsol 75%; Irving Oil 25%	Onshore
60	UK	Dragon LNG	2009	4.4	BG Group 50%; PETRONAS 30%; 4Gas 20%	Onshore
61	Kuwait	Mina Al-Ahmadi	2009	5.8	KPC 100%	Floating
62	Brazil	Pecém	2009	1.9	Petrobras 100%	Floating
63	Chile	Quintero LNG	2009	2.7	ENAGAS 20.4%; ENAP 20%; ENDESA 20%; Metrogas 20%; Oman Oil 19.6%	Onshore
64	China	Shanghai (Yangshan)	2009	3	Shenergy Group 55%; CNOOC 45%	Onshore
65	UK	South Hook	2009	15.6	Qatar Petroleum 67.5%; ExxonMobil 24.15%; TOTAL 8.35%	Onshore
66	Taiwan	Taichung LNG	2009	3	CPC 100%	Onshore
67	UAE	Dubai	2010	3	Dubai Supply Authority (Dusup) 100%	Floating
68	France	FosMax LNG (Fos Cavaou)	2010	6	GDF SUEZ 71.97%; TOTAL 28.03%	Onshore
69	Chile	Mejillones LNG	2010	1.5	GDF SUEZ 63%; Codelco 37%	Onshore
70	US	Neptune LNG	2010	3	GDF SUEZ 100%	Floating
71	China	Dalian	2011	3	PetroChina 75%; Dalian Port 20%; Dalian Construction Investment Corp 5%	Onshore
72	Netherlands	GATE LNG	2011	8.8	Gasunie 47.5%; Vopak 47.5%; EconGas OMV 5%	Onshore

73	US	Golden Pass	2011	15.6	Qatar Petroleum 70%; ExxonMobil 17.6%; ConocoPhillips 12.4%	Onshore
74	US	Gulf LNG (formerly Clean Energy Terminal)	2011	11.3	KM LNG Operating Partnership 50%; GE Energy Financial Services 30%; Sonangol 20%	Onshore
75	Argentina	Puerto Escobar	2011	3.8	Enarsa 100%	Floating
76	Thailand	Map Ta Phut LNG	2011	5	PTT 50%; Electricity Generating Authority of Thailand (EGAT) 25%; Electricity Generating Company 25%	Onshore
77	China	Rudong Jiangsu LNG	2011	3.5	PetroChina 55%; Pacific Oil and Gas 35%; Jiangsu Guoxin 10%	Onshore
78	Brazil	Guanabara LNG/Rio de Janeiro	2012	6	Petrobras 100%	Floating
79	Indonesia	Nusantara	2012	3.8	Pertamina 60%; PGN 40%	Floating
80	Japan	Ishikari LNG	2012	1.4	Hokkaido Gas 100%	Onshore
81	Japan	Joetsu	2012	2.3	Chubu Electric 100%	Onshore
82	Mexico	Manzanillo	2012	3.8	Mitsui 37.5%; Samsung 37.5%; KOGAS 25%	Onshore
83	China	Dongguan	2012	1	Jovo Group 100%	Onshore
84	Israel	Hadera Gateway	2013	3	Israel Natural Gas Lines 100%	Floating
85	India	Dabhol	2013	2	GAIL 31.52%; NTPC 31.52%; Indian financial institutions 20.28%; MSEB Holding Co. 16.68%	Onshore
86	Singapore	Jurong Island LNG	2013	6	Singapore Energy Market Authority 100%	Onshore
87	Malaysia	Lekas LNG (Malacca)	2013	3.8	PETRONAS 100%	Floating
88	China	Ningbo, Zhejiang	2013	3	CNOOC 51%; Zhejiang Energy Group Co Ltd 29%; Ningbo Power Development Co Ltd 20%	Onshore
89	China	Zhuhai (CNOOC)	2013	3.5	CNOOC 30%; Guangdong Gas 25%; Guangdong Yuedian 25%; Local companies 20%	Onshore
90	Italy	Livorno/LNG Toscana	2013	2.7	EON 46.79%; IREN 46.79%; OLT Energy 3.73%; Golar 2.69%	Floating
91	China	Tangshan Caofeidian LNG	2013	3.5	PetroChina 100%	Onshore
92	China	Tianjin (OS)	2013	2.2	CNOOC 100%	Floating
93	Japan	Naoetsu (Joetsu)	2013	2	INPEX 100%	Onshore
94	India	Kochi LNG	2013	5	Petronet LNG 100%	Onshore
95	Brazil	Bahia/TRBA (OS)	2014	3.8	Petrobras 100%	Floating
96	Indonesia	Lampung LNG	2014	1.8	PGN 100%	Floating
97	South Korea	Samcheok	2014	6.8	KOGAS 100%	Onshore
98	China	Hainan LNG	2014	2	CNOOC 65%; Hainan Development Holding Co 35%	Onshore
99	Japan	Hibiki LNG	2014	3.5	Saibu Gas 90%; Kyushu Electric 10%	Onshore
100	China	Shandong LNG	2014	3	Sinopec 99%; Qingdao Port Group 1%	Onshore
101	Lithuania	Klaipeda LNG	2014	3	Klaipedos Nafta 100%	Floating
102	Indonesia	Arun LNG	2015	3	Pertamina 70%; Aceh Regional Government 30%	Onshore

Sources: IHS, Company Announcements

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

Note: Construction on ENAGAS' El Musel terminal in Gijon (Spain) was completed in 2013. However, the terminal was immediately mothballed due to ongoing regulatory restrictions in Spain on the start-up of new regasification capacity. As such, it is not listed above.

APPENDIX IV: Table of LNG Receiving Terminals Under Construction

	Country	Terminal or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
103	Chile	Quintero LNG (Expansion)	2015	1.3	ENAGAS 20.4%; ENAP 20%; ENDESA 20%; Metrogas 20%; Oman Oil 19.6%	Onshore
104	China	Rudong Jiangsu LNG Phase 2	2015	3	CNPC 55%; Pacific Oil and Gas 35%; Jiangsu Guoxin 10%	Onshore
105	Pakistan	Engro LNG (OS) Phase 1	2015	2.3	Engro Corp (Pakistan) 100%	Floating
106	Egypt	Egypt LNG (OS)	2015	3.8	EGAS 100%	Floating
107	Uruguay	GNL Del Plata, Uruguay (OS)	2015	2.7	Ancap 50%; UTE 50%	Floating
108	China	Guangdong Dapeng LNG I (Expansion 2)	2015	2.3	CNOOC 33%; BP 30%; Shenzhen Gas 10%; Guangdong Yudean 6%; Guangzhou Gas Group 6%; Shenzhen Energy Group 4%; Hong Kong & China Gas 3%; Hong Kong Electric 3%; Dongguan Fuel Industrial 2.5%; Foshan Gas 2.5%	Onshore
109	Japan	Hachinohe LNG	2015	1.5	JX Nippon Oil & Energy 100%	Onshore
110	Poland	Swinoujscie	2015	3.6	GAZ-SYSTEM SA 100%	Onshore
111	Jordan	Jordan LNG (OS)	2015	3.8	Jordan Ministry of Energy and Mineral Resources (MEMR) 100%	Floating
112	China	Beihai, Guangxi LNG	2015	3	Sinopec 100%	Onshore
113	Japan	Ohgishima (Expansion II)	2015	0.5	Tokyo Gas 100%	Onshore
114	France	Dunkirk LNG	2015	10	EDF 65%; Fluxys 25%; TOTAL 10%	Onshore
115	China	Shenzhen (Diefu)	2015	4	CNOOC 70%; Shenzhen Energy Group 30%	Onshore
116	China	Tianjin (Sinopec) Phase 1	2015	2.9	Sinopec 100%	Onshore
117	China	Yuedong LNG (Jieyang)	2016	2	Shenergy Group 55%; CNOOC 45%	Onshore
118	India	Kakinada LNG (VGS) Phase 1	2016	3.6	Exmar 50%; VGS Group 50%	Floating
119	Greece	Revithoussa (Expansion Phase 2)	2016	1.9	DEPA 100%	Onshore
120	China	Tianjin (onshore)	2016	3.5	CNOOC 100%	Onshore
121	China	Yantai, Shandong Phase 1	2016	1.5	CNOOC 100%	Onshore
122	South Korea	Boryeong	2016	2	GS Energy 50%; SK Energy 50%	Onshore
123	India	Dahej LNG (Phase 3-A1)	2016	5	Petronet LNG 100%	Onshore
124	India	Mundra	2016	5	Adani Group 50%; GSPC 50%	Onshore
125	China	Fujian (Zhangzhou)	2017	3	CNOOC 100%	Onshore
126	Japan	Soma LNG	2018	1.5	Japex 100%	Onshore

Sources: IHS, Company Announcements

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

APPENDIX V: Table of Active LNG Fleet

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
AAMIRA	Nakilat	Samsung	Q-Max	2010	260,912	SSD	9443401
ABADI	Brunei Gas Carriers	Mitsubishi	Conventional	2002	135,269	Steam	9210828
ADAM LNG	Oman Shipping Co (OSC)	Hyundai	Conventional	2014	162,000	TFDE	9501186
AL AAMRIYA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	206,958	SSD	9338266
AL AREESH	Nakilat, Teekay	Daewoo	Conventional	2007	148,786	Steam	9325697
AL BAHIYA	Nakilat	Daewoo	Q-Flex	2010	205,981	SSD	9431147
AL BIDDA	J4 Consortium	Kawaski	Conventional	1999	135,466	Steam	9132741
AL DAAYEN	Nakilat, Teekay	Daewoo	Conventional	2007	148,853	Steam	9325702
AL DAFNA	Nakilat	Samsung	Q-Max	2009	261,988	SSD	9443683
AL DEEBEL	MOL, NYK, K Line	Samsung	Conventional	2005	142,795	Steam	9307176
AL GATTARA	Nakilat, OSC	Hyundai	Q-Flex	2007	216,200	SSD	9337705
AL GHARIYA	Commerz Real, Nakilat, PRONAV	Daewoo	Q-Flex	2008	205,941	SSD	9337987
AL GHARRAFA	Nakilat, OSC	Hyundai	Q-Flex	2008	216,200	SSD	9337717
AL GHASHAMIYA	Nakilat	Samsung	Q-Flex	2009	211,885	SSD	9397286
AL GHUWAIRIYA	Nakilat	Daewoo	Q-Max	2008	257,984	SSD	9372743
AL HAMLA	Nakilat, OSC	Samsung	Q-Flex	2008	211,862	SSD	9337743
AL HAMRA	National Gas Shipping Co	Kvaerner Masa	Conventional	1997	137,000	Steam	9074640
AL HUWAILA	Nakilat, Teekay	Samsung	Q-Flex	2008	214,176	SSD	9360879
AL JASRA	J4 Consortium	Mitsubishi	Conventional	2000	135,855	Steam	9132791
AL JASSASIYA	Maran G.M, Nakilat	Daewoo	Conventional	2007	142,988	Steam	9324435
AL KARAANA	Nakilat	Daewoo	Q-Flex	2009	205,988	SSD	9431123
AL KHARAITIYAT	Nakilat	Hyundai	Q-Flex	2009	211,986	SSD	9397327
AL KHARSAAH	Nakilat, Teekay	Samsung	Q-Flex	2008	211,885	SSD	9360881
AL KHATTIYA	Nakilat	Daewoo	Q-Flex	2009	205,993	SSD	9431111
AL KHAZNAH	National Gas Shipping Co	Mitsui	Conventional	1994	137,540	Steam	9038440
AL KHOR	J4 Consortium	Mitsubishi	Conventional	1996	135,295	Steam	9085613
AL KHUWAIR	Nakilat, Teekay	Samsung	Q-Flex	2008	211,885	SSD	9360908
AL MAFYAR	Nakilat	Samsung	Q-Max	2009	261,043	SSD	9397315
AL MARROUNA	Nakilat, Teekay	Daewoo	Conventional	2006	149,539	Steam	9325685
AL MAYEDA	Nakilat	Samsung	Q-Max	2009	261,157	SSD	9397298
AL NUAMAN	Nakilat	Daewoo	Q-Flex	2009	205,981	SSD	9431135
AL ORAIQ	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	205,994	SSD	9360790
AL RAYYAN	J4 Consortium	Kawaski	Conventional	1997	134,671	Steam	9086734
AL REKAYYAT	Nakilat	Hyundai	Q-Flex	2009	211,986	SSD	9397339
AL RUWAIS	Commerz Real, Nakilat, PRONAV	Daewoo	Q-Flex	2007	205,941	SSD	9337951
AL SADD	Nakilat	Daewoo	Q-Flex	2009	205,963	SSD	9397341
AL SAFLIYA	Commerz Real, Nakilat, PRONAV	Daewoo	Q-Flex	2007	210,100	SSD	9337963

AL SAHLA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Hyundai	Q-Flex	2008	211,842	SSD	9360855
AL SAMRIYA	Nakilat	Daewoo	Q-Max	2009	258,054	SSD	9388821
AL SHAMAL	Nakilat, Teekay	Samsung	Q-Flex	2008	213,536	SSD	9360893
AL SHEEHANIYA	Nakilat	Daewoo	Q-Flex	2009	205,963	SSD	9360831
AL THAKHIRA	K Line, Qatar Shpg.	Samsung	Conventional	2005	143,517	Steam	9298399
AL THUMAMA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Hyundai	Q-Flex	2008	216,235	SSD	9360843
AL UTOURIYA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Hyundai	Q-Flex	2008	211,879	SSD	9360867
AL WAJBAH	J4 Consortium	Mitsubishi	Conventional	1997	134,562	Steam	9085625
AL WAKRAH	J4 Consortium	Kawaski	Conventional	1998	134,624	Steam	9086746
AL ZUBARAH	J4 Consortium	Mitsui	Conventional	1996	135,510	Steam	9085649
ALTO ACRUX	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2008	147,798	Steam	9343106
AMALI	Brunei Gas Carriers	Daewoo	Conventional	2011	147,228	TFDE	9496317
AMANI	Brunei Gas Carriers	Hyundai	Conventional	2014	155,000	TFDE	9661869
ARCTIC AURORA	Dynagas	Hyundai	Conventional	2013	154,880	TFDE	9645970
ARCTIC DISCOVERER	K Line, Statoil, Mitsui, Iino	Mitsui	Conventional	2006	139,759	Steam	9276389
ARCTIC LADY	Hoegh	Mitsubishi	Conventional	2006	147,835	Steam	9284192
ARCTIC PRINCESS	Hoegh, MOL, Statoil	Mitsubishi	Conventional	2006	147,835	Steam	9271248
ARCTIC SPIRIT	Teekay	I.H.I.	Conventional	1993	87,305	Steam	9001784
ARCTIC VOYAGER	K Line, Statoil, Mitsui, Iino	Kawaski	Conventional	2006	140,071	Steam	9275335
ARKAT	Brunei Gas Carriers	Daewoo	Conventional	2011	147,228	TFDE	9496305
ARWA SPIRIT	Teekay, Marubeni	Samsung	Conventional	2008	163,285	DFDE	9339260
ASEEM	MOL, NYK, K Line, SCI, Nakilat, Petronet	Samsung	Conventional	2009	154,948	TFDE	9377547
ASIA ENERGY	Chevron	Samsung	Conventional	2014	154,948	TFDE	9606950
ASIA VISION	Chevron	Samsung	Conventional	2014	154,948	TFDE	9606948
BACHIR CHIHANI	Sonatrach	CNIM	Conventional	1979	129,767	Steam	7400675
BARCELONA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2009	173,400	TFDE	9401295
BEBATIK	Shell	Chantiers de l'Atlantique	Conventional	1972	75,056	Steam	7121633
BELANAK	Shell	Ch.De La Ciotat	Conventional	1975	75,000	Steam	7347768
BERGE ARZEW	BW	Daewoo	Conventional	2004	138,089	Steam	9256597
BILBAO KNUTSEN	Knutsen OAS	IZAR	Conventional	2004	135,049	Steam	9236432
BRITISH DIAMOND	BP	Hyundai	Conventional	2008	151,883	DFDE	9333620
BRITISH EMERALD	BP	Hyundai	Conventional	2007	154,983	DFDE	9333591
BRITISH INNOVATOR	BP	Samsung	Conventional	2003	136,135	Steam	9238040
BRITISH MERCHANT	BP	Samsung	Conventional	2003	138,517	Steam	9250191
BRITISH RUBY	BP	Hyundai	Conventional	2008	155,000	DFDE	9333606
BRITISH SAPPHIRE	BP	Hyundai	Conventional	2008	155,000	DFDE	9333618
BRITISH TRADER	BP	Samsung	Conventional	2002	138,248	Steam	9238038
BROOG	J4 Consortium	Mitsui	Conventional	1998	136,359	Steam	9085651
BU SAMRA	Nakilat	Samsung	Q-Max	2008	260,928	SSD	9388833

BW GDF SUEZ BOSTON	BW	Daewoo	Conventional	2003	138,059	Steam	9230062
BW GDF SUEZ BRUSSELS	BW	Daewoo	Conventional	2009	162,514	TFDE	9368314
BW GDF SUEZ EVERETT	BW	Daewoo	Conventional	2003	138,028	Steam	9243148
BW GDF SUEZ PARIS	BW	Daewoo	Conventional	2009	162,524	TFDE	9368302
CADIZ KNUTSEN	Knutsen OAS	IZAR	Conventional	2004	135,240	Steam	9246578
CASTILLO DE SANTISTEBAN	Anthony Veder	STX	Conventional	2010	173,673	TFDE	9433717
CASTILLO DE VILLALBA	Anthony Veder	IZAR	Conventional	2003	135,420	Steam	9236418
CATALUNYA SPIRIT	Teekay	IZAR	Conventional	2003	135,423	Steam	9236420
CELESTINE RIVER	K Line	Kawaski	Conventional	2007	145,394	Steam	9330745
CHEIKH BOUAMAMA	HYPROC, Sonatrach, Itochu, MOL	Universal	Conventional	2008	74,245	Steam	9324344
CHEIKH EL MOKRANI	HYPROC, Sonatrach, Itochu, MOL	Universal	Conventional	2007	73,990	Steam	9324332
CLEAN ENERGY	Dynagas	Hyundai	Conventional	2007	146,794	Steam	9323687
CLEAN FORCE	Dynagas	Hyundai	Conventional	2008	146,748	Steam	9317999
CLEAN OCEAN	Dynagas	Hyundai	Conventional	2014	162,000	TFDE	9637492
CLEAN PLANET	Dynagas	Hyundai	Conventional	2014	162,000	TFDE	9637507
COOL RUNNER	Thenamaris	Samsung	Conventional	2014	160,000	TFDE	9636797
COOL VOYAGER	Thenamaris	Samsung	Conventional	2013	160,000	TFDE	9636785
CORCOVADO LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636711
CUBAL	Mitsui, NYK, Teekay	Samsung	Conventional	2012	154,948	TFDE	9491812
CYGNUS PASSAGE	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2009	145,400	Steam	9376294
DAPENG MOON	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2008	147,200	Steam	9308481
DAPENG STAR	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2009	147,200	Steam	9369473
DAPENG SUN	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2008	147,200	Steam	9308479
DISHA	MOL, NYK, K Line, SCI, Nakilat	Daewoo	Conventional	2004	136,026	Steam	9250713
DOHA	J4 Consortium	Mitsubishi	Conventional	1999	135,203	Steam	9085637
DUHAIL	Commerz Real, Nakilat, PRONAV	Daewoo	Q-Flex	2008	210,100	SSD	9337975
DUKHAN	J4 Consortium	Mitsui	Conventional	2004	137,672	Steam	9265500
DWIPUTRA	P.T. Humpuss Trans	Mitsubishi	Conventional	1994	127,386	Steam	9043677
ECHIGO MARU	NYK	Mitsubishi	Conventional	1983	125,568	Steam	8110203
EJNAN	K Line, MOL, NYK, Mitsui, Nakilat	Samsung	Conventional	2007	143,815	Steam	9334076
EKAPUTRA	P.T. Humpuss Trans	Mitsubishi	Conventional	1990	136,400	Steam	8706155
ENERGY ADVANCE	Tokyo Gas	Kawaski	Conventional	2005	144,590	Steam	9269180
ENERGY CONFIDENCE	Tokyo Gas, NYK	Kawaski	Conventional	2009	152,880	Steam	9405588
ENERGY FRONTIER	Tokyo Gas	Kawaski	Conventional	2003	144,596	Steam	9245720
ENERGY HORIZON	NYK, TLTC	Kawaski	Conventional	2011	177,441	Steam	9483877
ENERGY NAVIGATOR	Tokyo Gas, MOL	Kawaski	Conventional	2008	147,558	Steam	9355264
ENERGY PROGRESS	MOL	Kawaski	Conventional	2006	144,596	Steam	9274226
ESSHU MARU	Trans Pacific Shipping	Mitsubishi	Conventional	2014	155,300	Steam	9666560

EXCALIBUR	Excelerate, Teekay	Daewoo	Conventional	2002	138,000	Steam	9230050
EXCEL	Exmar, MOL	Daewoo	Conventional	2003	135,344	Steam	9246621
EXCELERATE	Exmar, Excelerate	Daewoo	FSRU	2006	135,313	Steam	9322255
EXCELLENCE	Excelerate Energy	Daewoo	FSRU	2005	138,124	Steam	9252539
EXCELSIOR	Exmar	Daewoo	FSRU	2005	138,000	Steam	9239616
EXPLORER	Exmar, Excelerate	Daewoo	FSRU	2008	150,900	Steam	9361079
EXQUISITE	Excelerate Energy	Daewoo	FSRU	2009	151,035	Steam	9381134
FRAIHA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	205,950	SSD	9360817
FUJI LNG	Cardiff Marine	Kawaski	Conventional	2004	144,596	Steam	9275359
FUWAIRIT	K Line, MOL, NYK, Nakilat	Samsung	Conventional	2004	138,262	Steam	9256200
GALEA	Shell	Mitsubishi	Conventional	2002	135,269	Steam	9236614
GALICIA SPIRIT	Teekay	Daewoo	Conventional	2004	137,814	Steam	9247364
GALLINA	Shell	Mitsubishi	Conventional	2002	135,269	Steam	9236626
GASELYS	GDF SUEZ, NYK	Chantiers de l'Atlantique	Conventional	2007	151,383	DFDE	9320075
GASLOG CHELSEA	GasLog	Hanjin H.I.	Conventional	2010	153,000	DFDE	9390185
GASLOG SANTIAGO	GasLog	Samsung	Conventional	2013	154,948	TFDE	9600530
GASLOG SARATOGA	GasLog	Samsung	Conventional	2014	155,000	TFDE	9638903
GASLOG SAVANNAH	GasLog	Samsung	Conventional	2010	154,948	TFDE	9352860
GASLOG SEATTLE	GasLog	Samsung	Conventional	2013	154,948	TFDE	9634086
GASLOG SHANGHAI	GasLog	Samsung	Conventional	2013	154,948	TFDE	9600528
GASLOG SINGAPORE	GasLog	Samsung	Conventional	2010	154,948	TFDE	9355604
GASLOG SKAGEN	GasLog	Samsung	Conventional	2013	154,948	TFDE	9626285
GASLOG SYDNEY	GasLog	Samsung	Conventional	2013	154,948	TFDE	9626273
GDF SUEZ GLOBAL ENERGY	GDF SUEZ	Chantiers de l'Atlantique	Conventional	2004	74,130	Steam	9269207
GDF SUEZ NEPTUNE	Hoegh, MOL, TLTC	Samsung	FSRU	2009	145,130	Steam	9385673
GDF SUEZ POINT FORTIN	MOL, Sumitomo, LNG JAPAN	Imabari	Conventional	2010	154,982	Steam	9375721
GEMMATA	Shell	Mitsubishi	Conventional	2004	135,269	Steam	9253222
GHASHA	National Gas Shipping Co	Mitsui	Conventional	1995	137,100	Steam	9038452
GIGIRA LAITEBO	MOL, Itochu	Hyundai	Conventional	2010	173,870	TFDE	9360922
GIMI	Golar LNG	Rosenberg Verft	Conventional	1976	122,388	Steam	7382732
GOLAR ARCTIC	Golar LNG	Daewoo	Conventional	2003	137,814	Steam	9253105
GOLAR BEAR	Golar LNG	Samsung	Conventional	2014	160,000	TFDE	9626039
GOLAR CELSIUS	Golar LNG	Samsung	Conventional	2013	160,000	TFDE	9626027
GOLAR CRYSTAL	Golar LNG	Samsung	Conventional	2014	160,000	TFDE	9624926
GOLAR ESKIMO	Golar LNG	Samsung	FSRU	2014	160,000	TFDE	9624940
GOLAR FROST	Golar LNG	Samsung	Conventional	2014	160,000	TFDE	9655042
GOLAR GLACIER	Golar LNG	Hyundai	Conventional	2014	162,500	TFDE	9654696
GOLAR GRAND	Golar LNG Partners	Daewoo	Conventional	2005	145,700	Steam	9303560
GOLAR MARIA	Golar LNG Partners	Daewoo	Conventional	2006	145,700	Steam	9320374
GOLAR MAZO	Golar LNG Partners	Mitsubishi	Conventional	2000	135,000	Steam	9165011

GOLAR PENGUIN	Golar LNG	Samsung	Conventional	2014	160,000	TFDE	9624938
GOLAR SEAL	Golar LNG	Samsung	Conventional	2013	160,000	TFDE	9624914
GRACE ACACIA	NYK	Hyundai	Conventional	2007	146,791	Steam	9315707
GRACE BARLERIA	NYK	Hyundai	Conventional	2007	146,770	Steam	9315719
GRACE COSMOS	MOL, NYK	Hyundai	Conventional	2008	146,794	Steam	9323675
GRACE DAHLIA	NYK	Kawaski	Conventional	2013	177,425	Steam	9540716
GRAND ANIVA	NYK, Sovcomflot	Mitsubishi	Conventional	2008	145,000	Steam	9338955
GRAND ELENA	NYK, Sovcomflot	Mitsubishi	Conventional	2007	147,968	Steam	9332054
GRAND MEREYA	MOL, K Line, Primorsk	Mitsui	Conventional	2008	145,964	Steam	9338929
HANJIN MUSCAT	Hanjin Shipping Co.	Hanjin H.I.	Conventional	1999	138,366	Steam	9155078
HANJIN PYEONG TAEK	Hanjin Shipping Co.	Hanjin H.I.	Conventional	1995	130,366	Steam	9061928
HANJIN RAS LAFFAN	Hanjin Shipping Co.	Hanjin H.I.	Conventional	2000	138,214	Steam	9176008
HANJIN SUR	Hanjin Shipping Co.	Hanjin H.I.	Conventional	2000	138,333	Steam	9176010
HILLI	Golar LNG	Rosenberg Verft	FLNG	1975	124,890	Steam	7382720
HISPANIA SPIRIT	Teekay	Daewoo	Conventional	2002	137,814	Steam	9230048
HOEGH GALLANT	Hoegh	Hyundai	FSRU	2014	170,000	TFDE	9653678
HYUNDAI AQUAPIA	Hyundai LNG Shipping	Hyundai	Conventional	2000	134,400	Steam	9179581
HYUNDAI COSMOPIA	Hyundai LNG Shipping	Hyundai	Conventional	2000	134,308	Steam	9155157
HYUNDAI ECOPIA	Hyundai LNG Shipping	Hyundai	Conventional	2008	146,790	Steam	9372999
HYUNDAI GREENPIA	Hyundai LNG Shipping	Hyundai	Conventional	1996	125,000	Steam	9075333
HYUNDAI OCEANPIA	Hyundai LNG Shipping	Hyundai	Conventional	2000	134,300	Steam	9183269
HYUNDAI TECHNOPIA	Hyundai LNG Shipping	Hyundai	Conventional	1999	134,524	Steam	9155145
HYUNDAI UTOPIA	Hyundai LNG Shipping	Hyundai	Conventional	1994	125,182	Steam	9018555
IBERICA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2006	135,230	Steam	9326603
IBRA LNG	OSC, MOL	Samsung	Conventional	2006	145,951	Steam	9326689
IBRI LNG	OSC, MOL, Mitsubishi	Mitsubishi	Conventional	2006	145,173	Steam	9317315
ISH	National Gas Shipping Co	Mitsubishi	Conventional	1995	137,512	Steam	9035864
K. ACACIA	Korea Line	Daewoo	Conventional	2000	138,017	Steam	9157636
K. FREESIA	Korea Line	Daewoo	Conventional	2000	138,015	Steam	9186584
K. JASMINE	Korea Line	Daewoo	Conventional	2008	142,961	Steam	9373008
K. MUGUNGWHA	Korea Line	Daewoo	Conventional	2008	148,776	Steam	9373010
KITA LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636723
LALLA FATMA N'SOUMER	HYPROC	Kawaski	Conventional	2004	144,888	Steam	9275347
LARBI BEN M'HIDI	HYPROC	CNIM	Conventional	1977	129,500	Steam	7400663
LENA RIVER	Dynagas	Hyundai	Conventional	2013	154,880	TFDE	9629598
LIJMILIYA	Nakilat	Daewoo	Q-Max	2009	258,019	SSD	9388819
LNG ABUJA	Nigeria LNG Ltd	General Dynamics	Conventional	1980	126,530	Steam	7619575
LNG ADAMAWA	Nigeria LNG Ltd	Hyundai	Conventional	2005	142,656	Steam	9262211
LNG AKWA IBOM	Nigeria LNG Ltd	Hyundai	Conventional	2004	142,656	Steam	9262209

LNG AQUARIUS	Hanochem	General Dynamics	Conventional	1977	126,750	Steam	7390181
LNG BARKA	OSC, OG, NYK, K Line	Kawaski	Conventional	2008	152,880	Steam	9341299
LNG BAYELSA	Nigeria LNG Ltd	Hyundai	Conventional	2003	137,500	Steam	9241267
LNG BENUE	BW	Daewoo	Conventional	2006	142,988	Steam	9267015
LNG BONNY	Nigeria LNG Ltd	Kockums	Conventional	1981	132,588	Steam	7708948
LNG BORNO	NYK	Samsung	Conventional	2007	149,600	Steam	9322803
LNG CROSS RIVER	Nigeria LNG Ltd	Hyundai	Conventional	2005	142,656	Steam	9262223
LNG DREAM	Osaka Gas	Kawaski	Conventional	2006	147,326	Steam	9277620
LNG EBISU	MOL, KEPCO	Kawaski	Conventional	2008	147,546	Steam	9329291
LNG EDO	Nigeria LNG Ltd	General Dynamics	Conventional	1980	126,750	Steam	7619587
LNG ENUGU	BW	Daewoo	Conventional	2005	142,988	Steam	9266994
LNG FINIMA	Sahara Energy International (SEI)	Kockums	Conventional	1984	132,588	Steam	7702401
LNG FLORA	NYK	Kawaski	Conventional	1993	125,637	Steam	9006681
LNG IMO	BW	Daewoo	Conventional	2008	148,452	Steam	9311581
LNG JAMAL	NYK	Mitsubishi	Conventional	2000	136,977	Steam	9200316
LNG JUPITER	Osaka Gas, NYK	Kawaski	Conventional	2009	152,880	Steam	9341689
LNG KANO	BW	Daewoo	Conventional	2007	148,565	Steam	9311567
LNG LAGOS	Nigeria LNG Ltd	Chantiers de l'Atlantique	Conventional	1976	122,255	Steam	7360124
LNG LERICI	ENI	Sestri	Conventional	1998	63,993	Steam	9064085
LNG LIBRA	Hoegh	General Dynamics	Conventional	1979	126,000	Steam	7413232
LNG LOKOJA	BW	Daewoo	Conventional	2006	148,471	Steam	9269960
LNG MALEO	MOL, NYK, K Line	Mitsui	Conventional	1989	127,544	Steam	8701791
LNG OGUN	NYK	Samsung	Conventional	2007	149,600	Steam	9322815
LNG ONDO	BW	Daewoo	Conventional	2007	148,478	Steam	9311579
LNG OYO	BW	Daewoo	Conventional	2005	142,988	Steam	9267003
LNG PIONEER	MOL	Daewoo	Conventional	2005	138,000	Steam	9256602
LNG PORT HARCOURT	Nigeria LNG Ltd	Chantiers de l'Atlantique	Conventional	1977	122,255	Steam	7360136
LNG PORTOVENERE	ENI	Sestri	Conventional	1996	65,262	Steam	9064073
LNG RIVER NIGER	Nigeria LNG Ltd	Hyundai	Conventional	2006	142,656	Steam	9262235
LNG RIVER ORASHI	BW	Daewoo	Conventional	2004	142,988	Steam	9266982
LNG RIVERS	Nigeria LNG Ltd	Hyundai	Conventional	2002	137,500	Steam	9216298
LNG SOKOTO	Nigeria LNG Ltd	Hyundai	Conventional	2002	137,500	Steam	9216303
LNG SWIFT	NYK	Mitsubishi	Conventional	1989	127,580	Steam	8702941
LNG TAURUS	BGT Ltd.	General Dynamics	Conventional	1979	126,750	Steam	7390167
LNG VENUS	Osaka Gas, MOL	Mitsubishi	Conventional	2014	155,300	Steam	9645736
LNG VIRGO	General Dynamics	General Dynamics	Conventional	1979	126,750	Steam	7390179
LOBITO	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	TFDE	9490961
LUSAIL	K Line, MOL, NYK, Nakilat	Samsung	Conventional	2005	142,808	Steam	9285952
MADRID SPIRIT	Teekay	IZAR	Conventional	2004	135,423	Steam	9259276
MAGELLAN SPIRIT	Teekay, Marubeni	Samsung	Conventional	2009	163,194	DFDE	9342487

MALANJE	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	TFDE	9490959
MARAN GAS APOLLONIA	Maran Gas Maritime	Hyundai	Conventional	2014	164,000	TFDE	9633422
MARAN GAS ASCLEPIUS	Maran G.M, Nakilat	Daewoo	Conventional	2005	142,906	Steam	9302499
MARAN GAS CORONIS	Maran G.M, Nakilat	Daewoo	Conventional	2007	142,889	Steam	9331048
MARAN GAS DELPHI	Maran Gas Maritime	Daewoo	Conventional	2014	159,800	TFDE	9633173
MARAN GAS EFESSOS	Maran Gas Maritime	Daewoo	Conventional	2014	159,800	TFDE	9627497
MARAN GAS POSIDONIA	Maran Gas Maritime	Hyundai	Conventional	2014	164,000	TFDE	9633434
MARIB SPIRIT	Teekay, Marubeni	Samsung	Conventional	2008	163,280	DFDE	9336749
MATTHEW	GDF SUEZ	Newport News	Conventional	1979	126,540	Steam	7391214
MEKAINES	Nakilat	Samsung	Q-Max	2009	261,137	SSD	9397303
MERIDIAN SPIRIT	Teekay, Marubeni	Samsung	Conventional	2010	163,285	TFDE	9369904
MESAIMEER	Nakilat	Hyundai	Q-Flex	2009	211,986	SSD	9337729
METHANE ALISON VICTORIA	BG Group	Samsung	Conventional	2007	145,000	Steam	9321768
METHANE BECKI ANNE	GasLog	Samsung	Conventional	2010	167,416	TFDE	9516129
METHANE HEATHER SALLY	BG Group	Samsung	Conventional	2007	142,702	Steam	9321744
METHANE JANE ELIZABETH	GasLog	Samsung	Conventional	2006	145,000	Steam	9307190
METHANE JULIA LOUISE	GasLog	Samsung	Conventional	2010	167,416	TFDE	9412880
METHANE LYDON VOLNEY	BG Group	Samsung	Conventional	2006	145,000	Steam	9307205
METHANE MICKIE HARPER	BG Group	Samsung	Conventional	2010	167,400	TFDE	9520376
METHANE NILE EAGLE	BG, GasLog	Samsung	Conventional	2007	145,000	Steam	9321770
METHANE PATRICIA CAMILA	BG Group	Samsung	Conventional	2010	167,416	TFDE	9425277
METHANE PRINCESS	Golar LNG Partners	Daewoo	Conventional	2003	136,086	Steam	9253715
METHANE RITA ANDREA	GasLog	Samsung	Conventional	2006	145,000	Steam	9307188
METHANE SHIRLEY ELISABETH	BG Group	Samsung	Conventional	2007	142,800	Steam	9321756
METHANE SPIRIT	Teekay, Marubeni	Samsung	Conventional	2008	163,195	TFDE	9336737
METHANIA	Distrigas	Boelwerf	Conventional	1978	131,235	Steam	7357452
MILAHA QATAR	Nakilat, Qatar Shpg., SocGen	Samsung	Conventional	2006	145,140	Steam	9321732
MILAHA RAS LAFFAN	Nakilat, Qatar Shpg., SocGen	Samsung	Conventional	2004	136,199	Steam	9255854
MIN LU	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2009	145,000	Steam	9305128
MIN RONG	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2009	145,000	Steam	9305116
MOSTEFA BEN BOULAID	Sonatrach	Ch.De La Ciotat	Conventional	1976	125,260	Steam	7359955
MOURAD DIDOUCHE	Sonatrach	Chantiers de l'Atlantique	Conventional	1980	126,190	Steam	7400704
MOZAH	Nakilat	Samsung	Q-Max	2008	261,988	SSD	9337755
MRAWEH	National Gas Shipping Co	Kvaerner Masa	Conventional	1996	135,000	Steam	9074638
MUBARAZ	National Gas Shipping Co	Kvaerner Masa	Conventional	1996	135,000	Steam	9074626
MURWAB	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	205,971	SSD	9360805
NEO ENERGY	Tsakos	Hyundai	Conventional	2007	146,838	Steam	9324277

NIZWA LNG	OSC, MOL	Kawaski	Conventional	2005	145,469	Steam	9294264
NORTHWEST SANDERLING	North West Shelf Venture	Mitsubishi	Conventional	1989	125,452	Steam	8608872
NORTHWEST SANDPIPER	North West Shelf Venture	Mitsui	Conventional	1993	125,042	Steam	8913150
NORTHWEST SEAEAGLE	North West Shelf Venture	Mitsubishi	Conventional	1992	125,541	Steam	8913174
NORTHWEST SHEARWATER	North West Shelf Venture	Kawaski	Conventional	1991	125,660	Steam	8608705
NORTHWEST SNIPE	North West Shelf Venture	Mitsui	Conventional	1990	127,747	Steam	8608884
NORTHWEST STORMPETREL	North West Shelf Venture	Mitsubishi	Conventional	1994	125,525	Steam	9045132
NORTHWEST SWAN	North West Shelf Venture	Daewoo	Conventional	2004	140,500	Steam	9250725
OB RIVER	Dynagas	Hyundai	Conventional	2007	146,791	Steam	9315692
ONAIZA	Nakilat	Daewoo	Q-Flex	2009	205,963	SSD	9397353
PACIFIC ARCADIA	NYK	Mitsubishi	Conventional	2014	145,400	Steam	9621077
PACIFIC ENLIGHTEN	Kyushu Electric, TEPCO, Mitsubishi, Mitsui, NYK, MOL	Mitsubishi	Conventional	2009	147,800	Steam	9351971
PACIFIC EURUS	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2006	135,000	Steam	9264910
PACIFIC NOTUS	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2003	137,006	Steam	9247962
PALU LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636735
POLAR SPIRIT	Teekay	I.H.I.	Conventional	1993	88,100	Steam	9001772
PROVALYS	GDF SUEZ	Chantiers de l'Atlantique	Conventional	2006	151,383	DFDE	9306495
PSKOV	Sovcomflot	STX	Conventional	2014	170,200	TFDE	9630028
PUTERI DELIMA	MISC	Chantiers de l'Atlantique	Conventional	1995	127,797	Steam	9030814
PUTERI DELIMA SATU	MISC	Mitsui	Conventional	2002	134,849	Steam	9211872
PUTERI FIRUS	MISC	Chantiers de l'Atlantique	Conventional	1997	127,689	Steam	9030840
PUTERI FIRUS SATU	MISC	Mitsubishi	Conventional	2004	134,865	Steam	9248502
PUTERI INTAN	MISC	Chantiers de l'Atlantique	Conventional	1994	127,694	Steam	9030802
PUTERI INTAN SATU	MISC	Mitsubishi	Conventional	2002	134,770	Steam	9213416
PUTERI MUTIARA SATU	MISC	Mitsui	Conventional	2005	134,861	Steam	9261205
PUTERI NILAM	MISC	Chantiers de l'Atlantique	Conventional	1995	127,756	Steam	9030826
PUTERI NILAM SATU	MISC	Mitsubishi	Conventional	2003	134,833	Steam	9229647
PUTERI ZAMRUD	MISC	Chantiers de l'Atlantique	Conventional	1996	127,751	Steam	9030838
PUTERI ZAMRUD SATU	MISC	Mitsui	Conventional	2004	134,870	Steam	9245031
RAAHI	MOL, NYK, K Line, SCI, Nakilat	Daewoo	Conventional	2004	138,077	Steam	9253703
RAMDANE ABANE	Sonatrach	Chantiers de l'Atlantique	Conventional	1981	126,190	Steam	7411961
RASHEEDA	Nakilat	Samsung	Q-Max	2010	260,912	SSD	9443413
RIBERA DEL DUERO KNUTSEN	Knutsen OAS	Daewoo	Conventional	2010	173,400	TFDE	9477593
SALALAH LNG	OSC, MOL	Samsung	Conventional	2005	148,174	Steam	9300817
SALJU	PT Equinox	Hyundai	Conventional	2005	140,000	Steam	9256767
SEISHU MARU	Mitsubishi, NYK	Mitsubishi	Conventional	2014	155,300	Steam	9666558
SENSHU MARU	MOL, NYK, K Line	Mitsui	Conventional	1984	125,835	Steam	8014473

SERI ALAM	MISC	Samsung	Conventional	2005	145,572	Steam	9293832
SERI AMANAH	MISC	Samsung	Conventional	2006	142,795	Steam	9293844
SERI ANGGUN	MISC	Samsung	Conventional	2006	145,100	Steam	9321653
SERI ANGKASA	MISC	Samsung	Conventional	2006	142,786	Steam	9321665
SERI AYU	MISC	Samsung	Conventional	2007	143,474	Steam	9329679
SERI BAKTI	MISC	Mitsubishi	Conventional	2007	149,886	Steam	9331634
SERI BALHAF	MISC	Mitsubishi	Conventional	2009	154,567	TFDE	9331660
SERI BALQIS	MISC	Mitsubishi	Conventional	2009	154,747	TFDE	9331672
SERI BEGAWAN	MISC	Mitsubishi	Conventional	2007	149,964	Steam	9331646
SERI BIJAKSANA	MISC	Mitsubishi	Conventional	2008	149,822	Steam	9331658
SESTAO KNUTSEN	Knutsen OAS	IZAR	Conventional	2007	135,357	Steam	9338797
SEVILLA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2010	173,400	TFDE	9414632
SHAGRA	Nakilat	Samsung	Q-Max	2009	261,988	SSD	9418365
SHAHAMAH	National Gas Shipping Co	Kawaski	Conventional	1994	137,756	Steam	9035852
SHEN HAI	China LNG, CNOOC, Shanghai LNG	Hudong-Zhonghua	Conventional	2012	142,741	Steam	9583677
SIMAISMA	Maran G.M, Nakilat	Daewoo	Conventional	2006	142,971	Steam	9320386
SK SPLENDOR	SK Shipping	Samsung	Conventional	2000	135,540	Steam	9180231
SK STELLAR	SK Shipping	Samsung	Conventional	2000	135,540	Steam	9180243
SK SUMMIT	SK Shipping	Daewoo	Conventional	1999	135,933	Steam	9157624
SK SUNRISE	Iino Kaiun Kaisha	Samsung	Conventional	2003	135,505	Steam	9247194
SK SUPREME	SK Shipping	Samsung	Conventional	2000	136,320	Steam	9157739
SOHAR LNG	OSC, MOL	Mitsubishi	Conventional	2001	135,850	Steam	9210816
SOLARIS	GasLog	Samsung	Conventional	2014	154,948	TFDE	9634098
SONANGOL BENGUELA	Mitsui, Sonangol, Sojitz	Daewoo	Conventional	2011	160,500	Steam	9482304
SONANGOL ETOSHA	Mitsui, Sonangol, Sojitz	Daewoo	Conventional	2011	160,500	Steam	9482299
SONANGOL SAMBIZANGA	Mitsui, Sonangol, Sojitz	Daewoo	Conventional	2011	160,500	Steam	9475600
SOYO	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	TFDE	9475208
SPIRIT OF HELA	MOL, Itochu	Hyundai	Conventional	2009	173,800	TFDE	9361639
STENA BLUE SKY	Stena Bulk	Daewoo	Conventional	2006	142,988	Steam	9315393
STENA CLEAR SKY	Stena Bulk	Daewoo	Conventional	2011	173,593	TFDE	9413327
STENA CRYSTAL SKY	Stena Bulk	Daewoo	Conventional	2011	173,611	TFDE	9383900
STX KOLT	STX Pan Ocean	Hanjin H.I.	Conventional	2008	145,700	Steam	9372963
TAITAR NO. 1	CPC, Mitsui, NYK	Mitsubishi	Conventional	2009	144,627	Steam	9403669
TAITAR NO. 2	MOL, NYK	Kawaski	Conventional	2009	144,627	Steam	9403645
TAITAR NO. 3	MOL, NYK	Mitsubishi	Conventional	2010	144,627	Steam	9403671
TAITAR NO. 4	CPC, Mitsui, NYK	Kawaski	Conventional	2010	144,596	Steam	9403657
TANGGUH BATUR	Sovcomflot, NYK	Daewoo	Conventional	2008	142,988	Steam	9334284
TANGGUH FOJA	K Line, PT Meratus	Samsung	Conventional	2008	154,948	TFDE	9349007
TANGGUH HIRI	Teekay	Hyundai	Conventional	2008	151,885	TFDE	9333632
TANGGUH JAYA	K Line, PT Meratus	Samsung	Conventional	2008	154,948	TFDE	9349019

TANGGUH PALUNG	K Line, PT Meratus	Samsung	Conventional	2009	154,948	TFDE	9355379
TANGGUH SAGO	Teekay	Hyundai	Conventional	2009	151,872	TFDE	9361990
TANGGUH TOWUTI	NYK, PT Samudera, Sovcomflot	Daewoo	Conventional	2008	142,988	Steam	9325893
TEMBEK	Nakilat, OSC	Samsung	Q-Flex	2007	211,885	SSD	9337731
TENAGA EMPAT	MISC	CNIM	FSU	1981	130,000	Steam	7428433
TENAGA LIMA	MISC	CNIM	Conventional	1981	127,409	Steam	7428445
TENAGA SATU	MISC	Dunkerque Chantiers	FSU	1982	130,000	Steam	7428457
TRINITY ARROW	K Line	Imabari	Conventional	2008	152,655	Steam	9319404
TRINITY GLORY	K Line	Imabari	Conventional	2009	152,675	Steam	9350927
UMM AL AMAD	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	206,958	SSD	9360829
UMM AL ASHTAN	National Gas Shipping Co	Kvaerner Masa	Conventional	1997	137,000	Steam	9074652
UMM BAB	Maran G.M, Nakilat	Daewoo	Conventional	2005	143,708	Steam	9308431
UMM SLAL	Nakilat	Samsung	Q-Max	2008	260,928	SSD	9372731
VALENCIA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2010	173,400	TFDE	9434266
VELIKIY NOVGOROD	Sovcomflot	STX	Conventional	2014	170,471	TFDE	9630004
WILFORCE	Teekay	Daewoo	Conventional	2013	155,900	TFDE	9627954
WILGAS	Awilco	Mitsubishi	Conventional	1984	126,975	Steam	8125832
WILPRIDE	Teekay	Daewoo	Conventional	2013	156,007	TFDE	9627966
WOODSIDE DONALDSON	Teekay, Marubeni	Samsung	Conventional	2009	162,620	TFDE	9369899
WOODSIDE GOODE	Maran Gas Maritime	Daewoo	Conventional	2013	159,800	TFDE	9633161
WOODSIDE ROGERS	Maran Gas Maritime	Daewoo	Conventional	2013	159,800	TFDE	9627485
YARI LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636747
YENISEI RIVER	Dynagas	Hyundai	Conventional	2013	154,880	TFDE	9629586
YK SOVEREIGN	SK Shipping	Hyundai	Conventional	1994	124,582	Steam	9038816
ZARGA	Nakilat	Samsung	Q-Max	2010	261,104	SSD	9431214
ZEKREET	J4 Consortium	Mitsui	Conventional	1998	134,733	Steam	9132818

Sources: IHS, Company Announcements

APPENDIX VI: Table of LNG Vessel Orderbook

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
SCF MELAMPUS	Sovcomflot	STX	Conventional	2015*	170,200	TFDE	9654878
GOLAR SNOW	Golar LNG	Samsung	Conventional	2015*	160,000	TFDE	9635315
GOLAR KELVIN	Golar LNG	Hyundai	Conventional	2015*	162,000	TFDE	9654701
COOL EXPLORER	Thenamaris	Samsung	Conventional	2015*	160,000	TFDE	9640023
BW PAVILION VANDA	BW	Hyundai	Conventional	2015*	161,880	TFDE	9640437
PAPUA	MOL, China LNG	Hudong-Zhonghua	Conventional	2015*	172,000	TFDE	9613135
GOLAR ICE	Golar LNG	Samsung	Conventional	2015*	160,000	TFDE	9637325
ASIA EXCELLENCE	Chevron	Samsung	Conventional	2015*	154,948	TFDE	9610767
BW PAVILION LEEARA	BW	Hyundai	Conventional	2015	161,880	TFDE	9640645
CLEAN HORIZON	Dynagas	Hyundai	Conventional	2015	162,000	TFDE	9655444
GASLOG SALEM	GasLog	Samsung	Conventional	2015	155,000	TFDE	9638915
BW SINGAPORE	BW	Samsung	FSRU	2015	170,000	TFDE	9684495
CLEAN VISION	Dynagas	Hyundai	Conventional	2015	162,000	TFDE	9655456
MARAN GAS LINDOS	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	TFDE	9627502
MARAN GAS SPARTA	Maran Gas Maritime	Hyundai	Conventional	2015	162,000	TFDE	9650042
SCF MITRE	Sovcomflot	STX	Conventional	2015	170,200	TFDE	9654880
ASIA ENDEAVOUR	Chevron	Samsung	Conventional	2015	154,948	TFDE	9610779
MARAN GAS MISTRAS	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	TFDE	9658238
SOUTHERN CROSS	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	172,000	Steam Reheat	9613147
HOEGH GRACE	Hoegh	Hyundai	FSRU	2015	170,032	DFDE	9674907
AMADI	Brunei Gas Carriers	Hyundai	Conventional	2015	155,000	Steam Reheat	9682552
HYUNDAI SAMHO S688	Maran Gas Maritime	Hyundai	Conventional	2015	174,000	SSD	9682576
MARAN GAS TROY	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	DFDE	9658240
MITSUBISHI NAGASAKI 2296	Osaka Gas, MOL	Mitsubishi	Conventional	2015	155,300	DFDE	9645748
MARAN GAS ALEXANDRIA	Maran Gas Maritime	Hyundai	Conventional	2015	164,000	DFDE	9650054
ENERGY ATLANTIC	Alpha Tankers	STX	Conventional	2015	159,700	DFDE	9649328
N/B MITSUBISHI - MOL 1	MOL, KEPCO	Mitsubishi	Conventional	2015	155,300	DFDE	9666998
BEIDOU STAR	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	172,000	DFDE	9613159
HYUNDAI SAMHO S689	Maran Gas Maritime	Hyundai	Conventional	2015	174,000	DFDE	9682588
N/B Daewoo - TEEKAY 1	Teekay	Daewoo	Conventional	2015	173,400	DFDE	9681687
N/B HYUNDAI-NLNG1 2636	Nigeria LNG Ltd	Hyundai	Conventional	2015	177,000	DFDE	9692002
N/B MITSUBISHI - MOL 2	MOL	Mitsubishi	Conventional	2015	155,300	ME-GI	9696149
GOLAR TUNDRA	Golar LNG	Samsung	FSRU	2015	170,000	TFDE	9655808
N/B SAMSUNG-NLNG 1	Nigeria LNG Ltd	Samsung	Conventional	2015	170,000	TFDE	9690145
KAWASAKI SAKAIDE	K Line	Kawasaki Sakaide	Conventional	2015	164,700	Steam Reheat	9691137
N/B HYUNDAI-NLNG2 2637	Nigeria LNG Ltd	Hyundai	Conventional	2015	177,000	TFDE	9692014

N/B SAMSUNG-NLNG 2	Nigeria LNG Ltd	Samsung	Conventional	2015	170,000	TFDE	9690157
SAMSUNG Chevron 5	Chevron	Samsung	Conventional	2015	154,948	TFDE	9680188
HYUNDAI SAMHO S690	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	DFDE	9682590
MARIA ENERGY	Tsakos	Hyundai	Conventional	2016	174,000	TFDE	9659725
N/B SAMSUNG-NLNG 3	Nigeria LNG Ltd	Samsung	Conventional	2016	170,000	TFDE	9690169
DAEWOO 2418	Sovcomflot	Daewoo	Conventional	2016	170,000	TFDE	9737187
HUDONG-ZHONGHUA H1673A	MOL, China LNG	Hudong-Zhonghua	Conventional	2016	172,000	SSD	9613161
KAWASAKI SAKAIDE 1712	MOL, KEPCO	Kawasaki Sakaide	Conventional	2016	164,700	Steam Reheat	9666986
N/B Daewoo - TEEKAY 2	Teekay	Daewoo	Conventional	2016	173,400	ME-GI	9681699
N/B HUDONG SINOPEC 2	China Shipping Group	Hudong-Zhonghua	Conventional	2016	174,000	TFDE	9672820
N/B DAEWOO - MARAN 5	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9701217
DAEWOO 2456	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9753014
N/B DAEWOO - MARAN 7	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9732369
N/B HUDONG SINOPEC 3	China Shipping Group	Hudong-Zhonghua	Conventional	2016	174,000	TFDE	9672832
N/B SAMSUNG-NLNG 4	Nigeria LNG Ltd	Samsung	Conventional	2016	170,000	TFDE	9690171
SAMSUNG Chevron 6	Chevron	Samsung	Conventional	2016	154,948	TFDE	9680190
DAEWOO 2457	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9753026
N/B HYUNDAI-MARAN S734	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	DFDE	9709489
N/B HYUNDAI-NYK/SCI	NYK	Hyundai	Conventional	2016	173,000	TFDE	9723801
N/B SAMSUNG-GASLOG 9	GasLog	Samsung	Conventional	2016	174,000	TFDE	9687019
NORSPAN LNG 9	Knutsen OAS	Hyundai	Conventional	2016	176,300	ME-GI	9721724
KL-DAEWOO 1	Korea Line	Daewoo	Conventional	2016	174,000	ME-GI	9761827
GNL DEL PLATA	MOL	Daewoo	FSRU	2016	263,000	ME-GI	9713105
HYUNDAI SAMHO S691	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	ME-GI	9682605
N/B DAEWOO - MARAN 6	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	ME-GI	9701229
N/B HYUNDAI-PETRONAS 1	PETRONAS	Hyundai	Conventional	2016	150,200	ME-GI	9714276
SAMSUNG 2102	GasLog	Samsung	Conventional	2016	174,000	ME-GI	9707508
HYUNDAI-DAEWOO 1	Hyundai LNG Shipping	Daewoo	Conventional	2016	174,000	ME-GI	9761841
N/B DAEWOO - MARAN 8	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	ME-GI	9732371
N/B HUDONG SINOPEC 4	China Shipping Group	Hudong-Zhonghua	Conventional	2016	174,000	ME-GI	9672844
N/B HYUNDAI-MARAN S735	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	ME-GI	9709491
N/B KAWASAKI-Kline 1	K Line	Kawaski	Conventional	2016	182,000	ME-GI	9698123
N/B SAMSUNG-GASLOG 10	GasLog	Samsung	Conventional	2016	174,000	ME-GI	9687021
KL-DAEWOO 2	Korea Line	Daewoo	Conventional	2016	174,000	ME-GI	9761839
N/B BW FSRU 2	BW	Samsung	FSRU	2016	170,000	ME-GI	9724946
N/B HYUNDAI-PETRONAS 2	PETRONAS	Hyundai	Conventional	2016	150,200	ME-GI	9714288

N/B KAWASAKI-Unknown 1		Kawaski	Conventional	2016	164,700	ME-GI	9749609
N/B MITSUBISHI -KLINE 1	K-Line, Inpex	Mitsubishi	Conventional	2016	153,300	ME-GI	9698111
NORSPAN LNG 10	Knutsen OAS	Hyundai	Conventional	2016	176,300	ME-GI	9721736
HYUNDAI ULSAN 2813	HYPROC	Hyundai	Conventional	2016	171,800	ME-GI	9761243
HYUNDAI-DAEWOO 2	Hyundai LNG Shipping	Daewoo	Conventional	2016	174,000	ME-GI	9761853
KAWASAKI SAKAIDE 3	K Line	Kawasaki Sakaide	Conventional	2016	164,700	ME-GI	9766023
SK-SAMSUNG 2	SK Shipping	Samsung	Conventional	2016	174,000	ME-GI	9761815
N/B DAEWOO-TEEKAY 2411	Teekay	Daewoo	Conventional	2016	173,400	ME-GI	9721401
N/B SAMSUNG-GASLOG 12	GasLog	Samsung	Conventional	2016	174,000	ME-GI	9707510
HYUNDAI ULSAN 2814	HYPROC	Hyundai	Conventional	2017	171,800	ME-GI	9761267
KAWASAKI SAKAIDE 1	Mitsui & Co	Kawasaki Sakaide	Conventional	2017	155,000	ME-GI	9759240
N/B HYUNDAI-PETRONAS 3	PETRONAS	Hyundai	Conventional	2017	150,200	ME-GI	9714290
N/B SAMSUNG-SK/MARUBENI 2	SK Shipping, Marubeni	Samsung	Conventional	2017	180,000	ME-GI	9693161
HYUNDAI ULSAN	Hoegh	Hyundai	FSRU	2017	170,000	ME-GI	9762962
XIAMEN 1		Xiamen Shipbuilding Industry	Conventional	2017	45,000	ME-GI	9769855
HUDONG-ZHONGHUA H1718A	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	ME-GI	9694749
JAPAN MARINE UNITED TSU	MOL	Japan Marine	Conventional	2017	165,000	ME-GI	9736092
N/B Daewoo - TEEKAY 3	Teekay	Daewoo	Conventional	2017	173,400	ME-GI	9705641
N/B MI-NYK 1	NYK	Mitsubishi	Conventional	2017	155,300	ME-GI	9743875
N/B SAMSUNG-GASLOG 13	GasLog	Samsung	Conventional	2017	174,000	ME-GI	9744013
KAWASAKI SAKAIDE 2	Mitsui & Co	Kawasaki Sakaide	Conventional	2017	155,000	ME-GI	9759252
N/B MI-ELCANO 1	Elcano	Imabari	Conventional	2017	178,000	ME-GI	9742807
N/B DAEWOO 1		Daewoo	Conventional	2017	174,000	ME-GI	9762261
N/B DAEWOO 2		Daewoo	Conventional	2017	174,000	ME-GI	9762273
HUDONG-ZHONGHUA H1719A	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	ME-GI	9694751
N/B MI-ELCANO 2	Elcano	Imabari	Conventional	2017	178,000	ME-GI	9742819
N/B SAMSUNG-GASLOG 14	GasLog	Samsung	Conventional	2017	174,000	ME-GI	9744025
JAPAN MARINE UNITED TSU 5071	NYK	Japan Marine	Conventional	2017	165,000	TFDE	9752565
N/B DAEWOO 3		Daewoo	Conventional	2017	170,000	ME-GI	9762637
N/B DAEWOO - TEEKAY - Yamal 1	Teekay	Daewoo	Conventional	2017	172,000	Azimutal Thruster	9750696
N/B Daewoo - TEEKAY 4	Teekay	Daewoo	Conventional	2017	173,400	ME-GI	9705653
N/B HYUNDAI-GASLOG 1	GasLog	Hyundai	Conventional	2017	174,000	ME-GI	9748899
DAEWOO-Sovcomflot 1	Sovcomflot	Daewoo	Conventional	2017	172,000	Azimutal Thruster	9768368
DAEWOO-Sovcomflot 2	Sovcomflot	Daewoo	Conventional	2017	172,000	Azimutal Thruster	9768370
N/B HUDONG-TEEKAY 1	Teekay	Hudong-Zhonghua	Conventional	2017	174,000	Undecided	9750220
N/B HYUNDAI-GASLOG 2	GasLog	Hyundai	Conventional	2017	174,000	Undecided	9748904
N/B HYUNDAI-PETRONAS 4	PETRONAS	Hyundai	Conventional	2017	150,200	Undecided	9714305

DAEWOO 2435	BW	Daewoo	Conventional	2017	174,300	Undecided	9758064
JAPAN MARINE UNITED TSU 5072	MOL	Japan Marine	Conventional	2017	165,000	Undecided	9758832
N/B DAEWOO 4		Daewoo	Conventional	2017	170,000	Undecided	9762649
N/B HUDONG SINOPEC 1	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	Undecided	9672818
N/B SAMSUNG-SK/MARUBENI 1	SK Shipping, Marubeni	Samsung	Conventional	2017	180,000	Undecided	9693173
HYUNDAI ULSAN 2735	PETRONAS	Hyundai	Conventional	2017	150,200	Undecided	9756389
DAEWOO 2453	Teekay	Daewoo	Conventional	2017	173,400	Undecided	9770921
DAEWOO 2460	Chandris Group	Daewoo	Conventional	2018	174,000	Undecided	9766889
DAEWOO- Maran 1	Maran G.M, Nakilat	Daewoo	Conventional	2018	173,400	Undecided	9767950
N/B SAMSUNG-Flex 1	Flex LNG	Samsung	Conventional	2018	174,000	Undecided	9709025
N/B HUDONG-TEEKAY 2	Teekay	Hudong-Zhonghua	Conventional	2018	174,000	Undecided	9750232
DAEWOO 2436	BW	Daewoo	Conventional	2018	174,300	Undecided	9758076
DAEWOO 2454	Teekay	Daewoo	Conventional	2018	173,400	Undecided	9770933
JAPAN MARINE UNITED TSU 5073	MOL	Japan Marine	Conventional	2018	165,000	Undecided	9758844
N/B SAMSUNG 1	Mitsui & Co	Samsung	Conventional	2018	174,000	Undecided	9760768
N/B SAMSUNG 2	Mitsui & Co	Samsung	Conventional	2018	174,000	Undecided	9760770
N/B SAMSUNG 3	Mitsui & Co	Samsung	Conventional	2018	174,000	Undecided	9760782
N/B DAEWOO - TEEKAY - Yamal 2	Teekay	Daewoo	Conventional	2018	172,000	Azimutal Thruster	9750701
DAEWOO-Maran 2	Maran Gas Maritime	Daewoo	Conventional	2018	173,400	Undecided	9767962
N/B DAEWOO - MOL - Yamal 1	MOL	Daewoo	Conventional	2018	172,000	Azimutal Thruster	9750658
DAEWOO 2461		Daewoo	Conventional	2018	174,000	Undecided	9771080
DAEWOO-Sovcomflot 3	Sovcomflot	Daewoo	Conventional	2018	172,000	Azimutal Thruster	9768382
MITSUBISHI-NYK 1	NYK	Mitsubishi	Conventional	2018	177,000	Undecided	9770438
N/B SAMSUNG-Flex 2	Flex LNG	Samsung	Conventional	2018	174,000	Undecided	9709037
DAEWOO 2441	BP	Daewoo	Conventional	2018	174,000	Undecided	9766530
DAEWOO 2455	Teekay	Daewoo	Conventional	2018	173,400	Undecided	9770945
JAPAN MARINE UNITED TSU 5074	MOL	Japan Marine	Conventional	2018	165,000	Undecided	9758856
N/B HUDONG-TEEKAY 3	Teekay	Hudong-Zhonghua	Conventional	2018	174,000	Undecided	9750244
DAEWOO-Sovcomflot 4	Sovcomflot	Daewoo	Conventional	2018	172,000	Azimutal Thruster	9768394
DAEWOO 2442	BP	Daewoo	Conventional	2018	174,000	Undecided	9766542
MITSUI-MITSUBISHI	Mitsui & Co	Mitsubishi	Conventional	2018	177,000	Undecided	9770440
N/B DAEWOO - TEEKAY - Yamal 3	Teekay	Daewoo	Conventional	2018	172,000	Azimutal Thruster	9750713
DAEWOO 5	Mitsui & Co	Daewoo	Conventional	2018	180,000	Undecided	9771913
DAEWOO 2443	BP	Daewoo	Conventional	2018	174,000	Undecided	9766554
DAEWOO-Sovcomflot 5	Sovcomflot	Daewoo	Conventional	2018	172,000	Azimutal Thruster	9768526
DAEWOO 2444	BP	Daewoo	Conventional	2018	174,000	Undecided	9766566
N/B DAEWOO - MOL - Yamal 2	MOL	Daewoo	Conventional	2018	172,000	Azimutal Thruster	9750660
DAEWOO 2445	BP	Daewoo	Conventional	2019	174,000	Undecided	9766578

N/B HUDONG-TEEKAY 4	Teekay	Hudong-Zhonghua	Conventional	2019	174,000	Undecided	9750256
N/B DAEWOO - TEEKAY - Yamal 4	Teekay	Daewoo	Conventional	2019	172,000	Azimutal Thruster	9750725
DAEWOO 2446	BP	Daewoo	Conventional	2019	174,000	Undecided	9766580
DALIAN 1	China Shipping Group	Dalian Shipbuilding	Conventional	2019	174,000	Undecided	9769908
DALIAN 2	China Shipping Group	Dalian Shipbuilding	Conventional	2019	174,000	Undecided	9769910
N/B DAEWOO - TEEKAY - Yamal 5	Teekay	Daewoo	Conventional	2019	172,000	Azimutal Thruster	9750737
N/B DAEWOO - MOL - Yamal 3	MOL	Daewoo	Conventional	2019	172,000	Azimutal Thruster	9750672
N/B DAEWOO - TEEKAY - Yamal 6	Teekay	Daewoo	Conventional	2020	172,000	Azimutal Thruster	9750749

Sources: IHS, Company Announcements

** Vessels delivered in Q1 2015.*

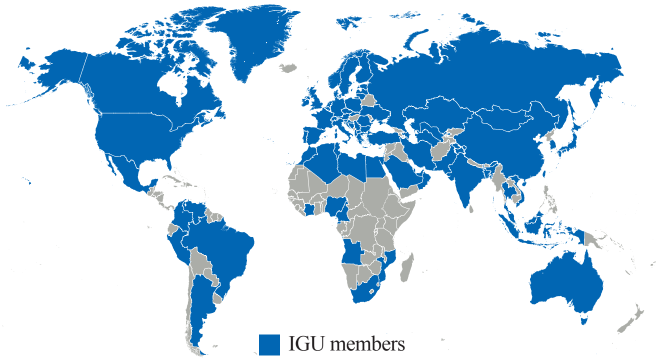
APPENDIX VII: Table of FSRU and Laid-up Vessels

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #	Status at end-2014
EXEMPLAR	Excelerate Energy	Daewoo	FSRU	2010	151,072	Steam	9444649	Chartered as FSRU
EXPEDIENT	Excelerate Energy	Daewoo	FSRU	2010	147,994	Steam	9389643	Chartered as FSRU
EXPERIENCE	Excelerate Energy	Daewoo	FSRU	2014	173,660	TFDE	9638525	Chartered as FSRU
EXPRESS	Exmar, Excelerate	Daewoo	FSRU	2009	150,900	Steam	9361445	Chartered as FSRU
FSRU TOSCANA	OLT Offshore LNG Toscana	Hyundai	Converted FSRU	2004	137,500	Steam	9253284	Chartered as FSRU
GDF SUEZ CAPE ANN	Hoegh, MOL, TLTC	Samsung	FSRU	2010	145,130	Steam	9390680	Chartered as FSRU
GOLAR FREEZE	Golar LNG Partners	HDW	Converted FSRU	1977	126,000	Steam	7361922	Chartered as FSRU
GOLAR IGLOO	Golar LNG Partners	Samsung	FSRU	2014	170,000	TFDE	9633991	Chartered as FSRU
GOLAR SPIRIT	Golar LNG Partners	Kawasaki Sakaide	Converted FSRU	1981	129,000	Steam	7373327	Chartered as FSRU
GOLAR WINTER	Golar LNG Partners	Daewoo	Converted FSRU	2004	138,000	Steam	9256614	Chartered as FSRU
INDEPENDENCE	Hoegh	Hyundai	FSRU	2014	170,132	TFDE	9629536	Chartered as FSRU
NUSANTARA REGAS SATU	Golar LNG Partners	Rosenberg Verft	Converted FSRU	1977	125,003	Steam	7382744	Chartered as FSRU
PGN FSRU LAMPUNG	Hoegh	Hyundai	FSRU	2014	170,000	TFDE	9629524	Chartered as FSRU
GANDRIA	Golar LNG	HDW	Conventional	1977	123,512	Steam	7361934	Laid-up
KOTO	BW	Kawaski	Conventional	1984	125,454	Steam	8210209	Laid-up
LNG CAPRICORN	BGT Ltd.	General Dynamics	Conventional	1978	126,750	Steam	7390208	Laid-up
LNG GEMINI	General Dynamics	General Dynamics	Conventional	1978	126,750	Steam	7390143	Laid-up
LNG LEO	General Dynamics	General Dynamics	Conventional	1978	126,750	Steam	7390155	Laid-up
LNG VESTA	Tokyo Gas, MOL, Iino	Mitsubishi	Conventional	1994	127,547	Steam	9020766	Laid-up
METHANE KARI ELIN	BG Group	Samsung	Conventional	2004	136,167	Steam	9256793	Laid-up
SUNRISE	Amethyst	Dunkerque Ateliers	Conventional	1977	126,813	Steam	7359670	Laid-up
TENAGA DUA	MISC	Dunkerque Normandie	Conventional	1981	127,400	Steam	7428469	Laid-up
TENAGA TIGA	MISC	Dunkerque Normandie	Conventional	1981	130,000	Steam	7428471	Laid-up
WILENERGY	Awilco	Mitsubishi	Conventional	1983	125,788	Steam	8014409	Laid-up
WILPOWER	Awilco	Kawaski	Conventional	1983	125,929	Steam	8013950	Laid-up

Sources: IHS, Company Announcement

IGU

The International Gas Union (IGU), founded in 1931, is a worldwide non-profit organisation promoting the political, technical and economic progress of the gas industry with the mission to advocate for gas as an integral part of a sustainable global energy system. IGU has more than 110 members worldwide and represents more than 95% of the world's gas market. The members are national associations and corporations of the gas industry. The working organization of IGU covers the complete value chain of the gas industry from upstream to downstream. For more information please visit www.igu.org.



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

Cover photo: ZAMORA PHILIPPE—TOTAL