2018 World LNG Report

27th World Gas Conference Edition

IGU
INTERNATIONAL GAS UNION
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Message from the President of the International Gas Union

Dear colleagues:

I am honored to host the 27th World Gas Conference in Washington, DC, as the United States is quickly becoming a significant new LNG exporter. On this occasion, the IGU is pleased to release the *2018 World LNG Report* to highlight the major LNG physical and market developments around the world.

International trade in liquefied natural gas (LNG) continues to be one of the most vibrant segments of the world's natural gas value chain, growing in 2017 by 35.2 million tonnes (MT), or 45.8 billion cubic meters, of natural gas, to 293.1 MT in global trade. That represents growth of 12% and comes as projects in Australia and the United States bring new capacity on line and Asian markets continue to grow. China and South Korea led Asian growth with additional demand of 12.7 MT and 4.9 MT, respectively. China has focused on aggregate energy demand toward natural gas and away from coal in its fight against air pollution.

In 2017, more traditional European trade patterns returned, including a move away from LNG re-loading due to global supply increases and stable demand. Spain, Italy, Portugal, and France returned to more traditional LNG uptake. In North America, Mexican imports of LNG were up, as additional low-cost U.S. shale gas imports were unavailable due to pipeline delays. Unlike 2016, the increases in world trade occurred without new major entrants to the world LNG market.

"International trade in liquefied natural gas (LNG) continues to be one of the most vibrant segments of the world's natural gas value chain, growing in 2017 by 35.2 MT… growth of 12%…"

Qatar continued to be the world's leading exporter of LNG, with 2017 liquefaction reaching 81.0 million tonnes per annum (MTPA), followed by Australia, Malaysia, Nigeria, Indonesia, and the United States Australia and the United States led in growth of exports by increases over 2016 of 11.9 MTPA and 10.2 MTPA, respectively. There are 92 MTPA of liquefaction capacity under construction world-wide, and we expect about one-third to come online this year in far-reaching locations of Australia, Cameroon, Indonesia, Malaysia, Russia, and the United States.

Thus far, the global market is absorbing new supply with minimal distortion, as new buyers and existing markets alike demonstrate a high need for natural gas to meet growing energy demand. The need for cleaner fuels that are available on-demand is a key part of this trend. Non-long-term trade (which includes "spot market" activity) increased yet again, reaching over 88 MT in 2017.

U.S. shale gas continues to moderate North American natural gas prices through technology and efficiency improvements, which translates into lower U.S. feedstock costs. Global LNG prices have seen a rebound as dictated by the international supply/demand balance. Average Northeast Asian spot prices have increased $1.33/MMBtu from 2016 to 2017, and averaged $9.88/MMBtu in January 2018, which is the highest price point in three years. Incremental supply during 2018 will impact the balance and may moderate prices.

IGU continues its strong support of LNG as a means of addressing world energy needs and satisfying societal demands for cleaner energy, both in terms of human health afforded by lower emissions and meeting climate goals for reduced greenhouse gas emissions. The innovation and flexibility of LNG through traditional trade channels and through floating and small-scale projects is demonstrating the global reach of the natural gas industry to address these needs. The World LNG Report is a testament to that progress.

Yours sincerely,

David Carroll
President of the International Gas Union

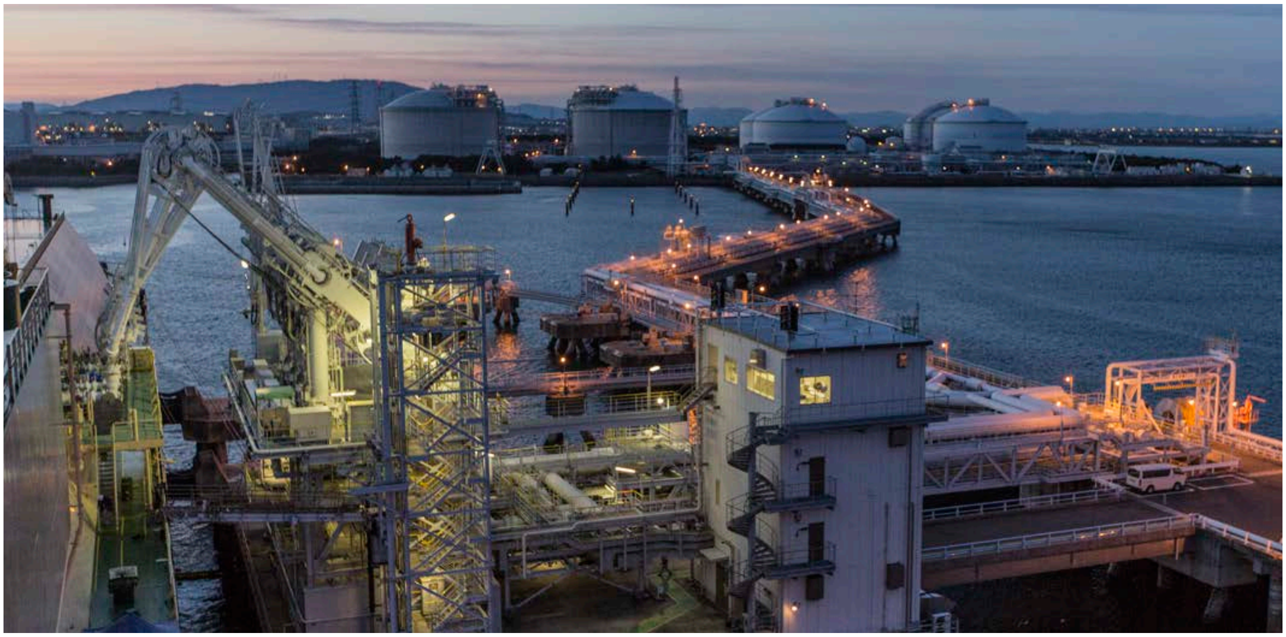


Photo courtesy of Chevron

2. State of the LNG Industry[1]

293.1 MT
Global trade in 2017

Global Trade: For the third consecutive year, global LNG trade set a record, reaching 293.1 million tonnes (MT). This marks an increase of 35.2 MT (+12%) from 2016; the second largest ever, only behind the 40 MT increase of 2010. The increase in trade was supported by a corresponding increase in LNG supply, driven by Australian and US projects. With additional trains at Australia Pacific LNG, Gorgon LNG, and higher production from existing trains, Australia added 11.9 MT of production in 2017. United States production gains of 10.2 MT were driven entirely by Sabine Pass LNG, which added two new trains in 2017. Asia continued to be the driver of global demand, with China growing by 12.7 MT – the largest annual growth by a single country ever. This was driven by the strong environmental policy designed to promote coal-to-gas switching. The other key countries driving global LNG growth include South Korea, Pakistan, Spain, and Turkey for a combined 11.9 MT. The Pacific Basin continues to be the key driver of trade growth, with intra-Pacific trade flows reaching a record 125 MT, shaped by Australian production and Chinese demand.

88 MT
Non long-term trade, 2017

Short and Medium Term LNG Market (as defined in Chapter 8): Non long-term LNG trade reached 88.3 MT in 2017, an increase of 16 MT year-on-year (YOY) and accounted for 30% of total gross LNG trade. The substantial increase in short-term trade in 2017 can be attributed to growing LNG supply and demand elasticity. New short-term supply largely came from ramp-ups in the Atlantic Basin, where new liquefaction capacity added during the year was contracted mostly to short-term traders and aggregators. Nearly 70% of exports from Sabine Pass LNG were traded on the non long-term market in 2017, and 100% of exports from the newly-restarted Angola LNG were sold under either spot or short-term contracts. Although China continues to receive volumes under new long-term contracts, the scale of its growth in 2017 meant that the country also had a substantial increase in short-term imports as well; the market's non long-term growth of 4.7 MT in 2017 was the largest of any importer.

$6.85/MMBtu
Average Northeast Asian spot price, 2017

Global Prices: Average Asian LNG prices (both spot and contracted) increased by $1.33 per million British thermal units (MMBtu) over 2016 owing to rising oil prices and stronger Pacific Basin demand, but most price markers experienced significant variation during the year. As new supply came online and slightly overwhelmed demand, LNG prices fell across the globe into the summer season, only to rise steadily in the second half of the year. After falling to $5.28/MMBtu in August 2017, landed Northeast Asian spot prices reached an average $9.88/MMBtu by January 2018 owing to the effects of a cold winter and strong demand from Chinese environmental regulation. The United Kingdom National Balancing Point (NBP) also experienced significant variation during the year, climbing from a low of $4.46/MMBtu in June to a high of $7.76/MMBtu in December. As prices rose globally, differentials between basins were similar to their level in 2016, with Asian spot prices spending a few notable months in the middle of the year at a discount to NBP again. However, by January 2018, Asian spot prices had climbed back to a $2.91/MMBtu premium to NBP.

[1] The scope of this report is limited only to international LNG trade, excluding small-scale projects, unless explicitly stated. Small-scale projects are defined as anything less than 0.5 MTPA for liquefaction, 1.0 MTPA for regasification, and 60,000 cm for LNG vessels. Domestic trade between terminals is also not included.

369 MTPA
Global nominal liquefaction capacity, March 2018

Liquefaction Plants: Global liquefaction capacity remains in the extended phase of build-out that began in 2016, driven largely by capacity in Australia and the United States. Between January 2017 and March 2018, 32.2 MTPA of liquefaction capacity was added. In engineering progress, the first floating liquefaction (FLNG) project came online in Malaysia, with additional FLNG projects set to come online during 2018 and beyond. Although no new liquefaction capacity had been added in Russia since Sakhalin 2 LNG T2 in 2010, the first train of Yamal LNG achieved commercial operations in March 2018 and is expected to ultimately add 17.4 MTPA of liquefaction capacity. Looking forward, Australia and the United States will continue to represent the majority of liquefaction capacity additions in the short term; including Wheatstone LNG, Prelude FLNG, and Ichthys LNG in the former; and Cove Point LNG, Freeport LNG, and Elba Island LNG in the latter. As of March 2018, 92.0 MTPA of liquefaction capacity was under construction. Only one project reached a final investment decision (FID) during 2017, Coral South FLNG (3.4 MTPA) – the first project to be sanctioned in Mozambique. While progress was made on other proposals, FID activity globally remains low in comparison to previous years.

875 MTPA
Proposed liquefaction capacity, March 2018

New Liquefaction Proposals: Although reaching FID has become a challenging prospect over the past few years, continued resource discovery and strong reserves have underpinned a growing list of proposed projects. As of March 2018, the total liquefaction capacity of proposed projects reached 875.5 MTPA, with the majority in the United States and Canada. Despite the large amount of proposed capacity in those two countries, the announcement in early 2017 by Qatar that it would lift the moratorium on production of its North Field to underpin new liquefaction trains, provides further potential supply. With many under-construction projects expected to contribute to strong global supply over the next few years, many developers have moved on to the early-2020s as the next available window in which to bring a new liquefaction project online.

851 MTPA
Global nominal regasification capacity, March 2018

Regasification Terminals: Global regasification capacity has continued to increase, rising to 851 MTPA by March 2018, out-pacing increases in liquefaction capacity. A total of 45 MTPA of regasification capacity was added during 2017, most of it during January 2017, as terminals that had been completed during 2016 began commercial operations. The key additions made during the second half of 2017 were all in Asia, including Pakistan, Thailand, and Malaysia. No new markets added large-scale regasification capacity during the year, for the first time in ten years[2]. Along with the rapid increase in liquefaction capacity expected through the end of the decade, additional regasification capacity is expected to be constructed. Additions will be in both mature markets which are experiencing increased gas demand, as well as in new markets where governments have made developing gas demand a priority. There remains an additional 87.7 MTPA of regasification capacity under construction as of March 2018. This includes capacity across several new markets, such as Bahrain, Bangladesh, Panama, the Philippines, and Russia. Of under-construction capacity, 37.7 MTPA of capacity is anticipated online during 2018, much of it in China.

84 MTPA[3]
FSRU capacity, March 2018

Floating Regasification: Three FSRU projects came online during 2017, boosting total regasification capacity of floating projects to 84 MTPA. A terminal at Pakistan's Port Qasim added 5.7 MTPA, and Turkey's first floating project, the Etki terminal, began operations in January 2017. As of March 2018, seven FSRUs were under construction. Many of these projects are in new markets, including Bahrain, Bangladesh, and Panama, showing the continued use of floating technologies to access new sources of demand. Other projects, such as those in India and Turkey, highlight the use of FSRUs in quickly addressing growing demand. As of January 2018, nine FSRUs were on the order book of shipbuilding yards. Furthermore, several FSRUs were open for charter, with some being used as conventional LNG carriers, indicating no immediate shortage of vessels for floating terminals.

478 Vessels
LNG fleet, end-2017

Shipping Fleet: The global LNG shipping fleet consisted of 478 vessels at the end of 2017, including conventional vessels and ships acting as FSRUs and floating storage units. In 2017, a total of 27 newbuilds (including three FSRUs) were delivered from shipyards. Relative to the previous year, this was a much more balanced addition relative to liquefaction capacity, but the accumulation of the tonnage buildout from the previous years kept short-term charter rates low for most of 2017. However, toward the end of the year, an increase in Asian spot purchases led short-term charter rates to rise; by December 2017, rates for dual-fuel diesel electric/tri-fuel diesel electric (DFDE/TFDE) tankers reached an average $81,700/day.

9.8% of Supply
Share of LNG in global gas supply in 2016[4]

LNG in the Global Gas Market: Natural gas accounts for just under a quarter of global energy demand, of which 9.8% is supplied as LNG. Although LNG supply previously grew faster than any other natural gas supply source – averaging 6.0% per annum from 2000 to 2016 – its market share growth has stalled since 2010 as indigenous production and pipeline supply have competed well for growing global gas markets. Despite the lack of market share growth in recent years, the large additions of LNG supply through 2020 mean LNG is poised to resume expansion.

[2] While Malta began LNG imports in 2017, its regasification terminal is small-scale at 0.4 MTPA of capacity, and thus is not included in regasification capacity totals, but is included in the trade balance.
[3] This 84 MTPA is included in the global regasification capacity total of 851 MTPA quoted above.
[4] Data for pipeline trade and indigenous gas production comes from the BP Statistical Review. Data for 2017 is not yet available.


Courtesy of Chevron

3. LNG Trade

After steady growth in recent years, global LNG trade increased sharply in 2017, rising by 35.2 MT to reach 293.1 MT. This marks the fourth consecutive year of incremental growth, and the second-largest annual increase ever (behind only 2010). The increase was driven by higher production at liquefaction plants in Australia, as well as full-year production and new trains at Sabine Pass LNG in the United States. Several older projects recorded increased production after working to solve feedstock or technical issues, including Nigeria LNG, Arzew and Skikda LNG, and Angola LNG. While it only produced minor volumes in 2017, the start of production at PFLNG Satu was notable as the world's first floating liquefaction project. Although there were concerns over the market's ability to absorb an increase in LNG supply as large as was experienced in 2017, global trade was bolstered by a series of demand stimuli throughout the year, as well as generally positive economic growth throughout global markets.

While China shared the spotlight with India and Egypt in 2016 as drivers of global LNG trade, China was a clear driver of LNG import growth during 2017, accounting for over one-third of net growth, rising by 12.7 MT. Also in the Pacific region, South Korea recorded the second-largest increase, with LNG demand supported by the power sector throughout the year to rise by 4.9 MT to 38.6 MT (2nd highest annual total for the country). Despite the increase in South Korea, China became the world's second largest LNG-importing country during the final quarter of the year.

Supply is set to continue its rapid expansion in 2018 as new plants and additional trains across the world come online, including Yamal LNG, Prelude FLNG, and Ichthys LNG. Although demand growth in China may not be as robust as in 2017, strong fundamentals will continue to support expansion in that market, as well as in many markets stretching from the Middle East to Southeast Asia. Increased LNG supply may result in additional deliveries to European markets with ample natural gas infrastructure, such as the United Kingdom, France, and Spain. Developers will also continue to look outside established markets to develop new demand; although notionally small, these emerging demand outlets could amount to substantial volumes in aggregate.

3.1 Overview

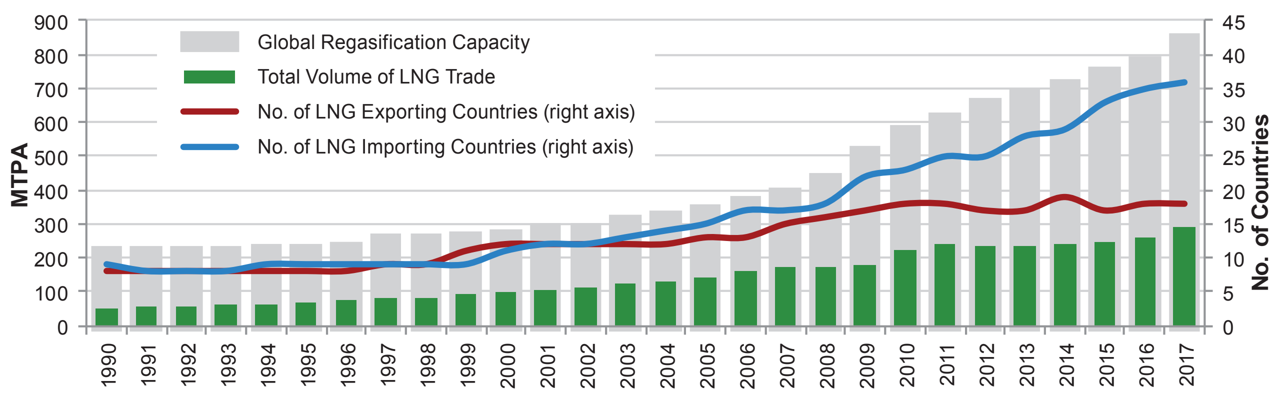
Globally-traded LNG volumes increased by 35.2 MT in 2017, setting a new annual record of 293.1 MT (see Figure 3.1). This marks the highest annual growth since 2010. While this growth is impressive, high-growth years are to be expected as additional liquefaction plants come online over the next few years.

293.1 MT
Global LNG trade reached a historic high in 2017

In 2017, the number of LNG-exporting countries in the market remained at 18 as all additional liquefaction capacity was added in countries that already contained export capabilities. Continued political instability in Yemen meant LNG exports were unable to restart after shutting down in mid-2015. The single greatest increase in LNG exports was by Australia, owing to new trains (Australia Pacific LNG T2, Gorgon LNG T3), new plants (Wheatstone LNG T1[1]), and higher utilization at existing facilities. The other key contributor to global LNG export growth was Sabine Pass LNG in the United States, which brought two additional trains online. After remaining stable during 2016, global re-export activity dropped by 39% YOY, with only 2.7 MT re-exported by 11 countries during the year (11 countries re-exported LNG in 2016).[2]

The Asia-Pacific region continues to be the leading LNG-exporting region, supplying 38.6% of total exports. This share is similar to its share of global exports in 2016, when it became the largest LNG-exporting region after being second to the Middle East from 2010–2015. Growth in exports from the Asia-Pacific was supported by new trains coming online and higher production from existing trains. Although the Asia-Pacific has grown in importance as an LNG-exporting region in recent years, Qatar is still the largest LNG-exporting country by a large margin. The country accounted for around 28% of total global LNG exports in 2016 (81.0 MT).

Figure 3.1 LNG Trade Volumes, 1990–2017



Source: IHS Markit, IEA, IGU

[1] The volumes from Wheatstone LNG T1 are considered to be commissioning volumes; the plant did not begin commercial operations until 2018.
[2] The United States is included in the total for 2016, since it exported domestically-produced LNG and re-exported LNG from regasification terminals in the Gulf of Mexico.

2016–2017 LNG Trade in Review

Global LNG Trade	LNG Exporters & Importers	LNG Re-Exports	LNG Price Change
+35.2 MTPA Growth of global LNG trade	**+1** Number of new LNG importers in 2017	**-1.8 MT** Re-exported volumes dropped by 39% YOY in 2017	**+$1.33** Rise in average Northeast Asian spot price from 2016 to 2017, in MMBtu
Global LNG trade reached an all-time high of 293.1 MT in 2017, rising above the previous of 258.0 MT set last year. China provided 12.7 MT in new import demand, while recovery in South Korea and Europe added 4.9 MT and 8.5 MT, respectively. Contractions were largest in the UK and Egypt (-2.5 MT and -1.1 MT, respectively).	The only new LNG importing market was Malta, which imported 0.3 MT to feed gas-fired power; however, its terminal is small-scale (0.4 MTPA) and thus is not included in Chapter 6: Regasification. All new liquefaction capacity was added in existing exporting countries. Production from Yemen has not yet restarted due to domestic issues in the country.	Re-export activity fell sharply during 2017 owing to better availability of supply in both basins, as well as more flexibility in delivery. The largest change came in Belgium, which did not re-export a single cargo above 10,000 tons; all its re-exports were smaller deliveries to European markets. Japan and the Dominican Republic both had their first re-export operations.	Spot prices rebounded in the winter of 2017-2018 in response to cold winter weather in Asia, as well as policy-driven spot purchases in China. Spot prices in general continue to face weakness in the summer and shoulder months due to supply additions outpacing demand growth.

Growth in Asia-Pacific supply (14.0 MT) was supported by the start-up of new trains at existing projects, including Gorgon LNG T3, Australia Pacific LNG T2, and MLNG T9. Increased production from plants that started late in 2016 or operated below nameplate capacity during 2016 also added to the growth in annual volumes from this region.

The United States continued its expected ramp-up of production, rising by 10.2 MT as Sabine Pass LNG T3 and T4 came online. Across the rest of the Atlantic Basin, production generally had positive results, particularly in Nigeria and Algeria, where LNG feedstock conditions improved, allowing for increases of 2.8 MT and 0.8 MT, respectively. Although Trinidad continued to struggle with feedstock limits, production at Atlantic LNG (ALNG) increased slightly (+0.2 MT) as new upstream projects came online throughout the year. Angola LNG, although still running below nameplate capacity for much of the year, reached 3.7 MT of exports, an increase of 2.9 MT from 2016. In sum, Atlantic Basin exports increased by 17.1 MT in 2017.

Imports into Asia-Pacific and Asia markets (the distinction between these regions is illustrated in Section 8.3) increased again during 2017, with the combined market share of the two regions rising from 72.4% in 2016 to 72.6% in 2017. This growth was driven primarily by China and South Korea (+12.7 MT and +4.9 MT, respectively). Smaller growth recorded across other major markets, such as Japan, India, and Taiwan, as well as smaller markets such as Pakistan and Thailand, helped these regions retain their important role in global trade.

The addition of Malta brought the number of importing countries to 36, although the country recorded just 0.3 MT of imports.[3] Of the six new markets added in 2015 and 2016, Pakistan had the largest growth during 2017, increasing its LNG imports by 2.4 MT, while Egyptian import volumes fell by 1.1 MT. Although imports into Poland and Jordan have continued to increase, Colombia has yet to begin importing LNG on a consistent basis, with just one LNG cargo delivered during 2017. Looking forward, new markets are likely to provide a greater impact than the smaller markets that opened during 2016–17, as Bangladesh and Panama are expected to begin importing LNG during 2018.

European LNG imports increased YOY for the third consecutive year (+8.5 MT), although strong Pacific Basin demand during the second half of the year, particularly in China and South Korea, continued to call volumes away from Northwest Europe. The Northwest European markets of the UK and Belgium declined by a combined 2.6 MT YOY as pipeline supplies from both Norway and Russia were readily available. Strong LNG demand across markets bordering the Mediterranean provided the greatest support to LNG imports in Europe; LNG imports into Spain (+2.3 MT), Italy (+1.5 MT), Portugal (+1.5 MT), and France (+2.0 MT) were boosted by low hydropower and strong air conditioning demand during the second and third quarters of the year. Turkish LNG imports were also robust as LNG remains a key source of natural gas for consumption during the colder months, rising by 2.3 MT for the year.

Total LNG imports into North America and Latin America did not experience strong growth during the year, with the recovery in

[3] All counts and totals within this section only include countries that imported LNG on conventionally-sized LNG carriers and above, and exclude countries that buy cargoes exclusively from domestic liquefaction plants, such as Indonesia. Hence, Malta and Jamaica are included in the trade balance, but not in the regasification capacity total due to their small-scale size. Refer to Chapter 11: References for a description of the categorization of small-scale versus large-scale LNG.

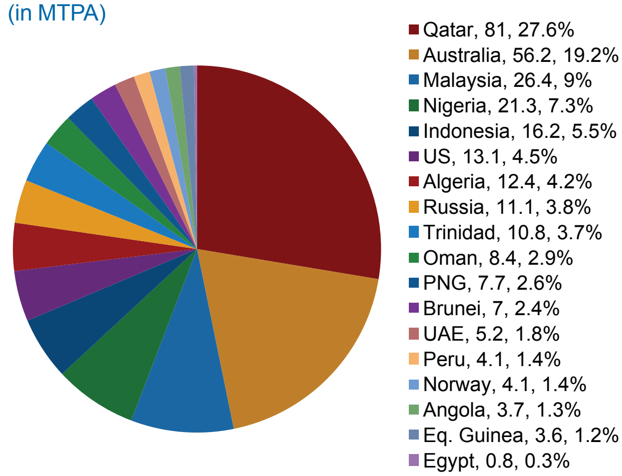
Mexican LNG imports (+0.8 MT) representing nearly the total combined increase of the two regions (+0.8 MT to 17.0 MT). Increased domestic gas demand and delayed pipeline flows from the United States were key factors supporting Mexican LNG demand. A start to economic recovery during 2017 and a slight increase in gas-in-power demand towards the end of the year encouraged a small recovery in LNG demand in Brazil (+0.3 MT). In contrast, stronger domestic production in Argentina caused LNG imports to decrease for the fourth consecutive year, while imports into Puerto Rico declined due the effects of Hurricane Maria.

The pace at which countries can bring LNG and natural gas infrastructure online in markets spanning South and Southeast Asia will have an important effect on global trade growth in 2018. Countries such as Bangladesh, Pakistan, and Thailand have ambitious plans for LNG imports, hoping to bring new regasification terminals online in the coming years. LNG imports into Japan are likely to trend downwards with nuclear power plant restarts, while Egypt continues to make progress towards its goal of ending LNG imports given rapidly-increasing domestic production.

European LNG imports will continue to be shaped by similar dynamics as those of 2017, including inter-basin price differentials, the decline of domestic production, and competition between pipeline gas, coal, and LNG. Gas supply via pipeline from both Russia and Norway will continue to compete with LNG in well-integrated European gas networks. It is unclear if the factors that provided boosts to gas-fired generation in recent times will be present again during 2018, including lower French nuclear generation, high coal prices, and weak continent-wide hydropower generation. However, if global LNG prices trend downward along with the projected increase in supply, the use of LNG in power generation could increase, leading to higher LNG imports.

From a supply perspective, the balance of new production will shift towards the Atlantic Basin, with projects including Yamal LNG, Kribi FLNG in Cameroon, and several US projects coming online. The last three projects in Australia's current expansion queue – Wheatstone LNG, Prelude FLNG, and Ichthys LNG – will come online during the year as well. Many trains that came online towards the end of 2017 will benefit from being run for the full year during 2018.

Figure 3.2: LNG Exports and Market Share by Country (in MTPA)



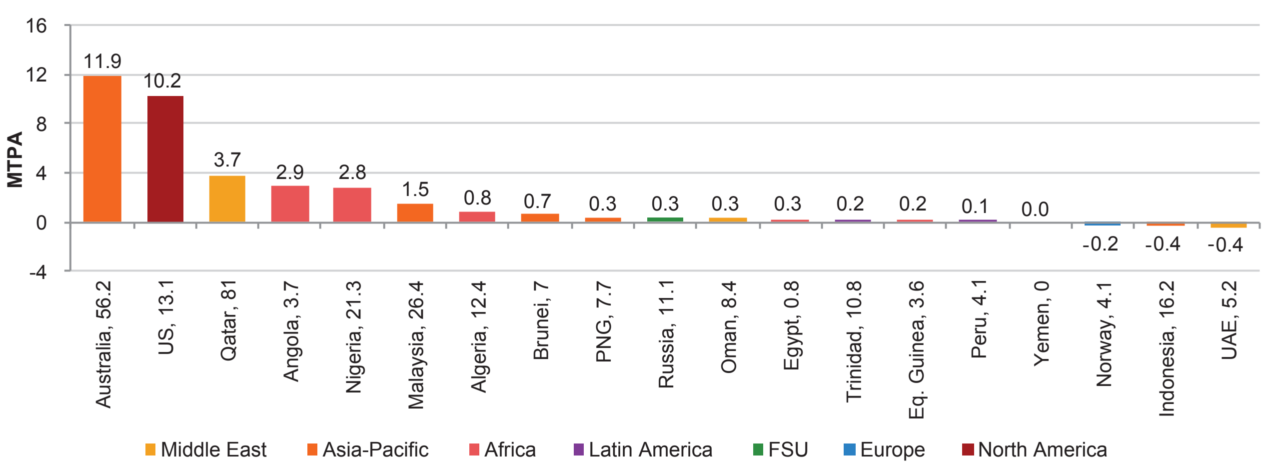
Note: Numbers in the legend represent total 2017 exports in MT, followed by market share. Source: IHS Markit, IGU

3.2. LNG Exports by Country

All new liquefaction capacity brought online during 2017 was in already-producing countries and Yemen LNG remained offline. As such, the number of exporting countries stayed at 18 during 2017. Additional LNG supply was relatively even between the Atlantic and Pacific Basins, with Australia and the United States (+11.9 MT and +10.2 MT, respectively) representing nearly 60% of new supply (see Figure 3.3). The partial resolution of issues with feedstock availability and technical aspects of existing projects in the Atlantic Basin, including Nigeria LNG, Arzew and Skikda LNG, Atlantic LNG, and Angola LNG, provided a boost to supply (total 6.8 MT between those four plants). In the Pacific Basin, increased production was recorded at several plants that were already running near nameplate capacity, including PNG LNG, Sakhalin 2 LNG, and Brunei LNG. In sum, total LNG exports increased by 35.2 MT (+13.6% YOY).

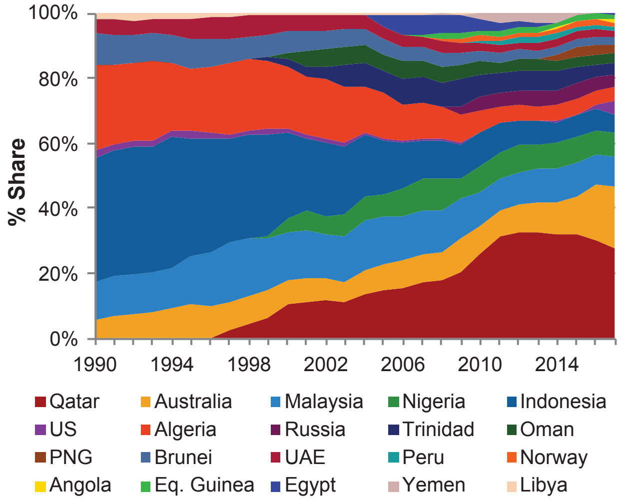
With exports of 81.0 MT, Qatar continued to be the largest LNG exporter, a position it has held for over a decade. Qatar's global market share continued to fall however, to 28%, as its production remains mostly stable while other countries have grown (see Figure 3.2).

Figure 3.3. 2017 Incremental LNG Exports by Country Relative to 2016 (in MTPA)



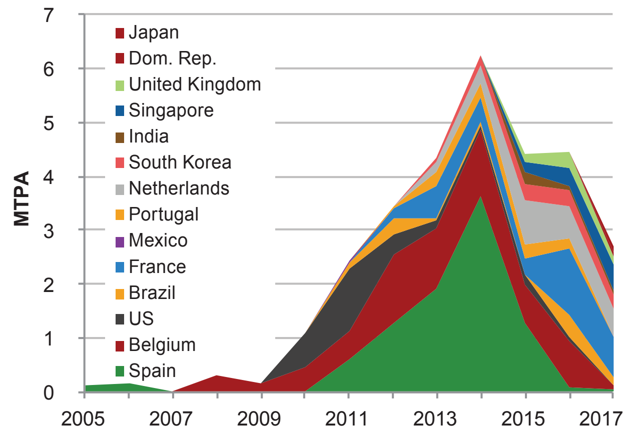
Source: IHS Markit, IGU

Figure 3.4 Share of Global LNG Exports by Country, 1990–2017



Source: IHS Markit, IGU

Figure 3.5: Re-exports by Country, 2005–2017



Note: Re-exports figures exclude volumes that were reloaded and discharged within the same country. Source: IHS Markit

The order of the top five exporters by share (Qatar, Australia, Malaysia, Nigeria, Indonesia, respectively) remained the same between 2015 and 2017. Although Australia remains the clear second-largest exporter, it gained significant ground in 2017 and is poised to do so again in 2018 with three new liquefaction projects. With a full year of production at all four trains at Sabine Pass LNG, as well as the new projects Cove Point LNG, Freeport LNG, and Elba Island LNG, the United States will be able to move up the ranks of producers again in 2018. Cameroon is set to join the group of LNG-exporting countries when operations start at Kribi FLNG during the first half of 2018.

Just three countries recorded decreases in LNG exports during 2017 – Indonesia, Norway, and the UAE (see Figure 3.3). Indonesian exports fell owing to maturing feedstock sources, despite less LNG being needed to supply domestic demand. In the UAE, a tighter balance between feedgas and domestic demand caused a dip in exported volumes. Norwegian exports also declined, but only slightly (40,000 tons, less than one cargo). This was the result of scheduled maintenance during May-June 2017, rather than any plant or feedgas issues.

Many countries that had exported lower amounts of LNG during 2016 – including Nigeria, Algeria, Trinidad, Brunei, and Equatorial Guinea – rebounded during 2017. In Nigeria, strong gas production as well as a lack of disruptions due to local unrest allowed exports to reach a record 21.3 MT. In Algeria, several new gas projects came online, leading to an increase of 0.8 MT to reach 12.4 MT of exports – the country's highest since 2014. Trinidad, despite recording decreases in exports during the first part of the year, ended the year with an increase in exports due to a series of new upstream projects coming online. Also in the Atlantic Basin, Angolan production had its highest annual production yet, reaching 3.7 MT. An increase in annual production could occur again in 2018 as the country's lone liquefaction plant, Angola LNG, has a nameplate capacity of 5.2 MTPA.

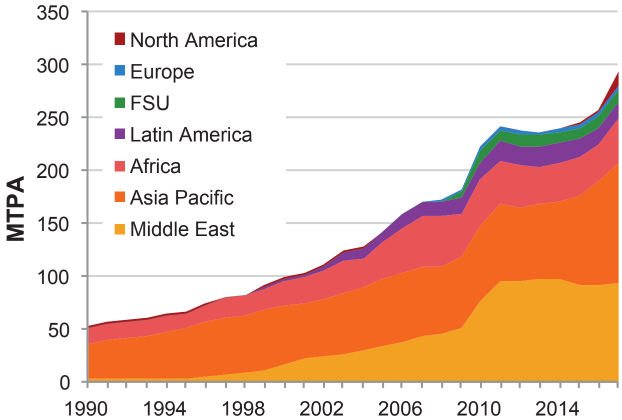
2.7 MT
Re-exported LNG volumes in 2017

Re-exported volumes dropped during 2017, falling by 39% to just 2.7 MT (less than 1% of global trade). The number of countries that re-exported LNG remained at 11; this included no re-exports by Portugal and the United States and the first re-exports from Japan and the Dominican Republic. The decline in re-exports is generally indicative of reduced price differentials between the Atlantic and Pacific Basins, the latter of which in the past has tended to be the recipient of re-exported cargoes.

Another factor that reduced re-exports was heightened LNG demand in Europe – typically the primary source of re-exported cargoes – which encouraged LNG volumes to remain in that continent. Europe registered a decrease of 1.8 MT in re-exports (see Figure 3.5). The most notable decrease in re-export activity occurred in Belgium, where no conventionally-sized cargoes were re-exported during 2017, the first such occurrence since re-exports began at Zeebrugge in 2008. After rising to a new peak in 2016 (1.2 MT), French re-exports fell in 2017 as fewer arbitrage opportunities presented themselves. A key trend that emerged in 2017 was high gas demand across Southern Europe supporting re-exports to those markets, including a handful from Northwest Europe to Spain and Turkey, as well as a pair of intra-France re-exports.

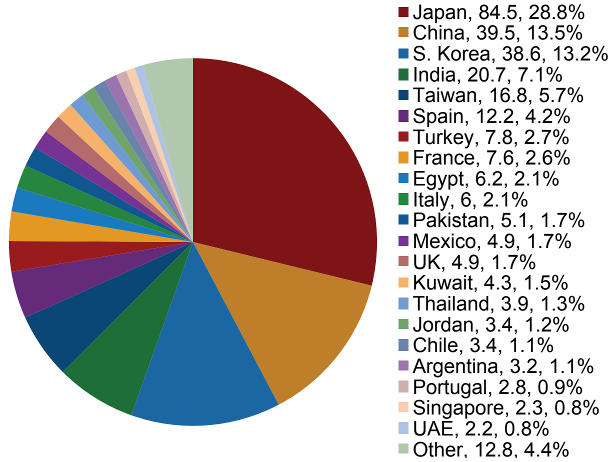
Re-export trade will continue to face downward pressure given the effect of new LNG supply coming to the market. As the Pacific Basin has typically been the demand-side driver of re-export activity, owing to its large demand and high spot prices during the winter, better Pacific Basin supply via new Australian LNG output may reduce opportunities for cross-basin arbitrage. Moreover, much of the increased supply from the Atlantic Basin is destination-flexible. The strong expected increase in global LNG supply relative to fundamentals-driven demand growth is likely to reduce the opportunities for cross-basin arbitrage.

Figure 3.6: LNG Exports by Region, 1990–2017



Note: FSU = Former Soviet Union. Sources: IHS Markit, IGU

Figure 3.7. LNG Imports and Market Share by Country (in MTPA)



Note: Number legend represents total imports in MT, followed by market share %. "Other" includes countries with imports less than 2.0 MT (by order of size): United States, Brazil, Malaysia, Poland, Greece, Belgium, Dominican Republic, Puerto Rico, Lithuania, Netherlands, Israel, Canada, Malta, Jamaica, and Colombia. Sources: IHS Markit, IGU

The lead in LNG production that was established by the Asia Pacific region during 2016 was expanded upon during 2017 to 113.5 MT (+14.0 MT YOY; see Figure 3.6). The Middle East remained the clear second-place exporting region due to Qatar's industry-leading 77 MT of nameplate capacity. The Middle East received additional support with better output at Oman LNG, although exports from the UAE decreased. Still, exports from Yemen LNG have yet to restart owing to domestic instability in the country.

LNG supply from North America was produced entirely by Sabine Pass LNG in the United States, which brought its third and fourth trains online and benefitted from full-year production at the first two trains. In Latin America, exports increased modestly (+0.4 MT) owing to increased exports from Peru LNG and better feedstock availability during the second half of the year at Atlantic LNG. During 2018, LNG exports from the Americas are likely to be supported again almost entirely by increased production from the United States, although this time several liquefaction plants will be featured instead of just one.

Table 3.1: LNG Trade Between Basins, 2017, MT

Exporting Region / *Importing Region*	Africa	Asia-Pacific	Europe	Former Soviet Union	Latin America	Middle East	North America	Reexports Received	Reexports Loaded	Total
Africa	1.6		0.2		0.1	4.1	0.2	0.1		**6.2**
Asia	7.1	29.3	0.2	0.5	0.4	24.7	1.9	1.2	0.1	**65.3**
Asia-Pacific	5.0	83.9	0.1	10.5	1.2	43.7	3.4	0.6	0.9	**147.5**
Europe	20.5		3.4	0.1	4.4	17.4	2.0	0.4	1.5	**46.7**
Latin America	1.6				5.7	1.6	1.4	0.1	0.2	**10.2**
Middle East	4.6	0.1	0.2		0.8	3.1	1.3	0.3		**10.4**
North America	1.4	0.2	0.1		2.3		2.9			**6.8**
Total	**41.8**	**113.5**	**4.1**	**11.1**	**15.0**	**94.6**	**13.1**	**2.7**	**-2.7**	**293.1**

Sources: IHS Markit, EIA, IGU

3.3. LNG Imports by Country

New markets played a diminished role in LNG import growth, with the new markets of 2016 and 2017 – Colombia, Jamaica, and Malta – importing only a combined 0.5 MT in 2017. Although Pakistan, a new market from 2015, recorded strong growth of 2.4 MT, fellow new markets from 2015 Jordan and Poland recorded slower growth (total +0.9 MT in 2017), and Egyptian LNG imports contracted (-1.1 MT). Instead, it was the major Asia and Asia Pacific[4] markets that boosted LNG imports, with China and South Korea increasing their LNG take by 12.7 MT and 4.9 MT, respectively.

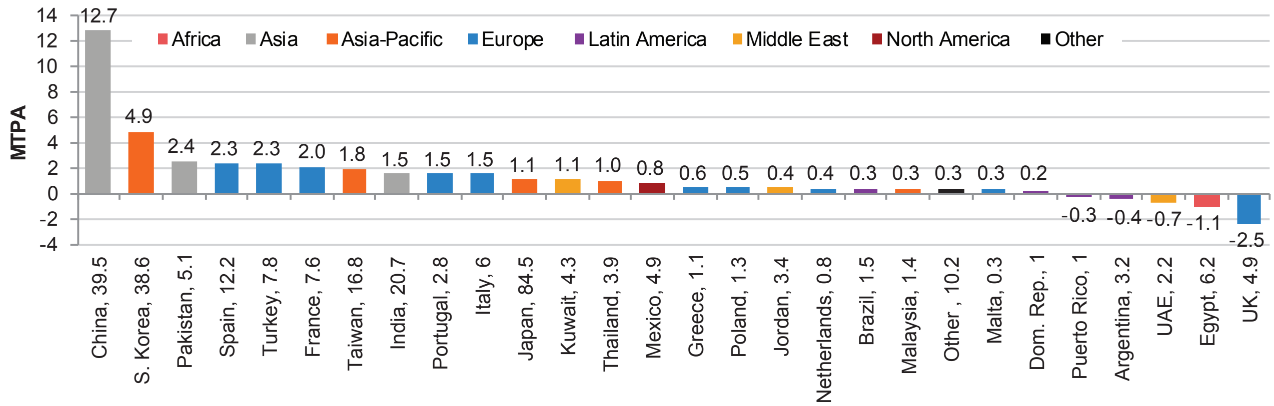
Asia Pacific remained the largest importing region in 2017, taking in just over half of global supply at 50.3%. This is the fourth straight year of declining market share for the region, which is reflective largely of the rise of imports into Asia, led by China, and a recovery in European imports. Demand in Asia-Pacific continues to be led by Japan (84.5 MT), with South Korea (38.6 MT) a distant second in the region. As in 2016, Asia-Pacific buyers received an increased amount of LNG from sellers within the region, causing intra-regional trade to rise again, to 83.9 MT in 2017 from 76.5 MT in 2016.

Asia firmed its position as the second-largest importing region during 2017, recording the highest increase by region (16.7 MT) to reach 65.3 MT. Asia was home to the primary driver of LNG import growth, China (+12.7 MT), with growth in Pakistan (+2.4 MT) and India (+1.5 MT) as well. All three of these countries are likely to experience continued import growth during 2018. Furthermore, a key new regional market, Bangladesh, will receive its first cargoes during 2018. Buyers in the region continued to source primarily from a mix of Middle East and Asia Pacific suppliers (providing 83% of regional supply).

Strong import growth occurred in Europe during 2017 owing largely to increased use in power generation. Lower nuclear generation early in the year and weak hydropower generation throughout the second and third quarters supported LNG

[4] In this chapter, the Asia region includes China, India, and Pakistan, while the remainder of countries on the Asian continent are included in the Asia-Pacific region. Please refer to Chapter 11: References for the exact definitions of each region.

Figure 3.8: Incremental 2017 LNG Imports by Country & Incremental Change Relative to 2016 (in MTPA)



Note: "Other" includes countries with incremental imports of less than ±0.2 MT: Chile, Singapore, the United States, Lithuania, Belgium, Israel, Canada, Jamaica, and Colombia. Sources: IHS Markit, IGU

demand in Spain, France, Portugal, and Italy (+7.3 MT combined). With different supply and weather dynamics, Turkey experienced a strong need for gas during its colder months, with annual LNG imports rising by 2.3 MT. Poland, which began imports in 2015, received increased cargoes in 2017 and is likely to do so again in 2018 owing to the startup of additional supply contracts. Europe received a higher proportion of its LNG from North America and Latin America during 2017 than during 2016, although Africa and the Middle East remained the dominant sources of supply.

After two years of consecutive import declines, North America and Latin America had a modest increase of 0.8 MT during 2017. Moreover, much of this was due to increased LNG imports into Mexico (+0.8 MT) given decreased domestic gas production. The other North American markets, the United States and Canada, continued to have minimal need for LNG, with the two showing flat growth YOY.

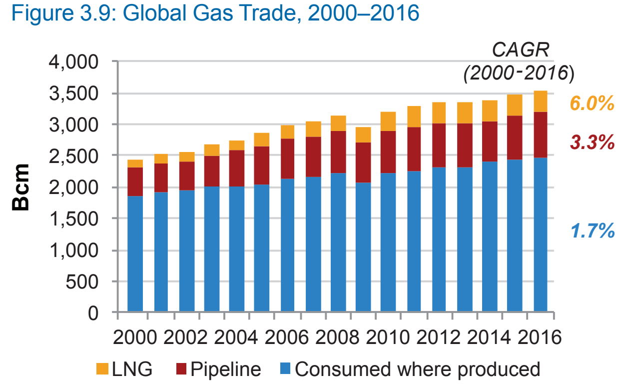
LNG imports into Argentina continued to fall (-0.4 MT) given steadily increasing domestic gas production. Chilean LNG imports increased slightly with higher power sector demand (+0.1 MT YOY). The country again repeated the export of regasified LNG into Argentina, as had taken place during 2016. The region's two new markets in 2016, Colombia and Jamaica, provided little support to LNG imports, rising by a combined 0.1 MMt. This was primarily due to imports into the latter, as high hydropower generation in the former obviated the need for LNG used in power generation. Net Brazilian LNG imports increased modestly YOY (+0.3 MT) owing to economic recovery.

Unlike the previous two years, emerging markets were not a driver of LNG import growth during 2017. Instead, the mature gas markets of China, South Korea, Spain, Turkey, Portugal, and Taiwan were strong drivers of import growth (although Pakistan was an exception to this trend). In China, policy changes supported coal-to-gas switching, while lower nuclear availability supported LNG imports in South Korea and Taiwan. In Spain and Portugal, strong power sector demand amidst low hydropower generation increased the call on gas-fired plants, while in Turkey heating demand was the strongest driver of LNG imports.

As in 2016, the largest single country increase in LNG imports during 2017 occurred in China, owing to increased enforcement of environmental policies that mandate the use of gas instead of coal in industrial and heating boilers across the population centres in the north of the country. Chinese LNG imports rose by 12.7 MT YOY, making it the second-largest single LNG market by the end of the year as it overtook South Korea, despite growth in LNG demand in that country (see Figure 3.8). The continued ramp-up in supply in Australia and Russia throughout 2018 will support Chinese demand, owing to Chinese contracted offtake at plants in both countries. Chinese imports were sourced largely from Australia and Qatar, which together represented a combined 26.0 MT of deliveries to the market in 2017, compared with 17.4 MT in 2016.

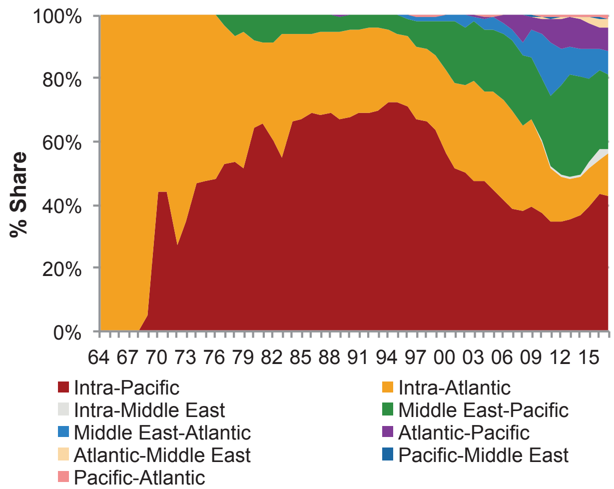
Beyond the Iberian Peninsula, European demand was supported by lower hydropower generation across several regional power networks, increasing the call on gas-fired power. This was particularly the case in France, Italy, and Greece (+4.0 MT YOY). Northwest Europe continued to record lower LNG imports during 2017, with the UK having the largest contraction amongst any market globally (-2.5 MT).

Figure 3.9: Global Gas Trade, 2000–2016



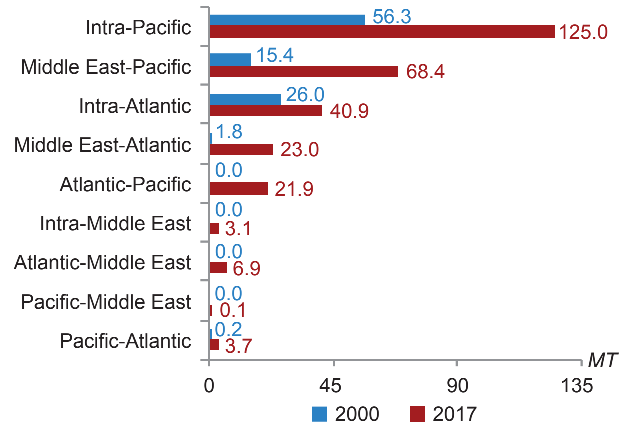
Note: CAGR = Compound Annual Growth Rate
Sources: IHS Markit, BP Statistical Review of World Energy

Figure 3.10: Inter-Basin Trade Flows 1964–2017



Sources: IHS Markit, IGU

Figure 3.11: Inter-Basin Trade, 2000 v. 2017



Sources: IHS Markit, IGU

The decrease in LNG imports was disproportionate to the decrease in UK gas demand, highlighting the flexibility of this very liquid market in substituting pipeline gas. Combined Belgian and Dutch LNG imports were relatively flat YOY despite slightly higher gas demand and lower Dutch domestic gas production, again reflecting the availability of pipeline imports from Norway and Russia.

Although LNG has posted a higher annual rate of growth over the past 15 years than either global production for indigenous consumption or international pipeline exports, much of the impressive growth was focused in the first decade, with pipeline trade displaying a similar growth rate to LNG over the past few years (see Figure 3.9). Between 2011 and 2016, the average growth rate of LNG trade slowed to just 0.9%, roughly on par with pipeline trade (1.0%), although both lagged behind indigenous production (1.7%). In 2016, LNG's share of global gas trade was flat, remaining around 9.8%, while pipeline's share increased again, rising to 20.8%. Pipeline trade into Europe was a key factor, with both Russian and Norwegian gas exports to Europe hitting a record during the year.

+ 6.0% p.a.
Average yearly growth rate of LNG demand since 2000

Despite a slowing rate of growth in recent years, LNG trade has continued to develop for reasons that vary by country and region. In Japan, South Korea, and Taiwan (JKT), LNG imports are driven by geographic remoteness and gas resource scarcity. Additionally, uncertainties regarding nuclear power continue to support LNG imports. Unlike some other importing regions, these countries either find themselves without prospects for increased domestic gas production, and cross-border pipeline connections have yet to make a major impact on regional gas dynamics.

In other markets, LNG is used to supplement domestic production, which is either maturing or insufficient to keep pace with domestic demand. In Europe, long-term decline continues for two traditional producers, the Netherlands and the United Kingdom. Furthermore, in a multitude of markets, there has been an inability of gas production to keep pace with demand growth; including in Kuwait, Thailand, and China.

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Table 3.2: LNG Trade Volumes Between Countries, 2017 (in MTPA)

	Algeria	Angola	Australia	Brunei	Egypt	Equatorial Guinea	Indonesia	Malaysia	Nigeria	Norway	Oman	Papua New Guinea	Peru	Qatar	Russia	Trinidad	United Arab Emirates	United States	Yemen	Re-exports Received	Re-exports Loaded	2017 Net Imports	2016 Net Imports	2015 Net Imports	2014 Net Imports	2013 Net Imports	2012 Net Imports
Egypt	0.42	0.14	-	-	-	0.07	-	-	0.95	0.20	-	-	-	4.08	-	0.06	-	0.20	-	0.07	-	6.19	7.32	3.02	-	-	-
Africa	0.42	0.14	-	-	-	0.07	-	-	0.95	0.20	-	-	-	4.08	-	0.06	-	0.20	-	0.07	-	6.19	7.32	3.02	-	-	-
China	0.06	0.28	17.84	0.13	0.06	0.14	3.08	4.13	0.36	0.06	0.25	1.96	0.07	8.19	0.46	0.13	-	1.50	-	0.79	-	39.49	26.78	19.83	19.81	18.60	14.77
India	0.19	1.05	1.78	-	0.19	0.87	0.13	0.26	3.20	0.12	0.53	-	-	11.12	-	0.18	0.39	0.34	-	0.46	(0.07)	20.72	19.17	14.67	14.48	12.92	13.99
Pakistan	-	-	-	-	-	0.25	-	-	0.49	-	-	-	-	4.24	-	0.06	-	0.06	-	-	-	5.11	2.68	1.11	-	-	-
Asia	0.25	1.33	19.62	0.13	0.24	1.26	3.22	4.39	4.05	0.18	0.78	1.96	0.07	23.55	0.46	0.37	0.39	1.90	-	1.25	(0.07)	65.32	48.64	35.61	34.29	31.52	28.76
Japan	0.07	0.14	25.93	3.94	0.13	0.34	6.79	14.71	1.52	-	2.82	3.94	0.32	11.00	6.96	0.12	4.61	0.99	-	0.27	(0.13)	84.48	83.34	85.58	88.69	87.79	87.26
Malaysia	-	-	0.58	0.86	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.43	1.13	1.57	1.60	1.62	-
Singapore	0.06	0.07	1.35	-	0.07	0.06	-	0.14	-	-	-	-	-	1.04	-	-	-	-	-	-	(0.51)	2.29	2.12	2.10	1.89	0.94	-
South Korea	0.13	0.28	7.08	1.57	-	0.14	3.63	3.76	1.10	0.07	4.21	0.06	0.34	12.01	1.93	0.18	-	2.16	-	0.18	(0.26)	38.56	33.71	33.36	37.81	40.86	36.78
Taiwan	0.07	-	1.07	0.45	-	-	2.15	3.11	0.54	-	0.12	1.74	0.06	5.27	1.65	0.23	0.06	0.18	-	0.14	-	16.84	15.04	14.63	13.59	12.83	12.78
Thailand	0.07	-	0.51	-	-	0.06	0.20	0.32	0.15	-	-	-	-	2.48	-	-	0.06	0.06	-	-	-	3.91	2.90	2.58	1.31	1.42	0.98
Asia-Pacific	0.40	0.49	36.51	6.82	0.20	0.61	12.76	22.04	3.31	0.07	7.15	5.74	0.72	31.80	10.54	0.53	4.74	3.39	-	0.59	(0.90)	147.51	138.24	139.82	144.88	145.46	137.80
Belgium	-	-	-	-	-	-	-	-	-	0.07	-	-	-	0.97	-	-	-	-	-	0.09	(0.06)	1.07	1.21	1.89	0.90	1.10	1.91
France	3.20	0.14	-	-	0.06	-	-	-	2.47	0.57	-	-	0.26	1.54	-	0.06	-	-	-	-	(0.75)	7.55	5.59	4.54	4.72	5.80	7.48
Greece	0.96	-	-	-	-	-	-	-	-	0.04	-	-	-	0.12	-	-	-	-	-	-	-	1.11	0.56	0.42	0.40	0.51	1.07
Italy	0.63	-	-	-	0.06	-	-	-	0.07	0.13	-	-	-	4.78	-	0.23	-	0.14	-	-	-	6.04	4.54	4.21	3.35	4.25	5.23
Lithuania	-	-	-	-	-	-	-	-	0.07	0.66	-	-	-	-	-	0.06	-	0.14	-	-	-	0.92	1.02	0.33	0.11	-	-
Malta	-	-	-	-	-	0.06	-	-	-	-	-	-	-	-	-	0.18	-	0.01	-	0.01	-	0.26	-	-	-	-	-
Netherlands	0.04	-	-	-	-	-	-	-	0.08	0.44	-	-	-	0.56	0.07	-	-	0.06	-	-	(0.50)	0.75	0.36	0.63	0.47	0.32	0.61
Poland	-	-	-	-	-	-	-	-	-	0.06	-	-	-	1.13	-	-	-	0.07	-	-	-	1.26	0.79	0.08	-	-	-
Portugal	0.21	0.07	-	-	-	-	-	-	1.58	-	-	-	-	0.44	-	-	-	0.42	-	0.06	-	2.78	1.28	1.16	0.98	1.32	1.66
Spain	1.77	0.19	-	-	0.07	-	-	-	3.31	0.67	-	-	2.64	2.56	-	0.40	-	0.56	-	0.08	(0.06)	12.19	9.88	8.91	8.20	9.36	14.22
Turkey	3.45	-	-	-	-	0.20	-	-	1.51	0.67	-	-	-	1.00	-	0.31	-	0.57	-	0.13	-	7.84	5.55	5.55	5.32	4.24	5.74
United Kingdom	0.17	-	-	-	-	-	-	-	0.07	0.06	-	-	0.06	4.32	0.07	0.17	-	0.07	-	0.05	(0.15)	4.90	7.37	9.79	8.47	6.84	10.45
Europe	10.44	0.41	-	-	0.20	0.27	-	-	9.14	3.37	-	-	2.96	17.42	0.15	1.40	-	2.03	-	0.42	(1.52)	46.67	38.15	37.51	32.92	33.74	48.37
Argentina	0.06	-	-	-	-	0.45	-	-	0.38	-	-	-	0.04	1.32	-	0.55	-	0.32	-	0.04	-	3.16	3.58	4.19	4.68	4.93	3.82
Brazil	-	0.29	-	-	-	-	-	-	0.40	-	-	-	-	0.22	-	0.32	-	0.34	-	0.07	(0.15)	1.48	1.13	5.22	5.71	4.44	2.52
Chile	-	-	-	-	-	0.06	-	-	-	-	-	-	-	0.03	-	2.77	-	0.51	-	-	-	3.37	3.28	3.01	2.78	2.86	3.03
Colombia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.03	-	-	-	-	-	0.03	0.06	-	-	-	-
Dominican Republic	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.88	-	0.18	-	-	(0.05)	1.01	0.78	0.95	0.92	1.09	0.96
Jamaica	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.17	-	-	-	-	-	0.17	0.06	-	-	-	-
Puerto Rico	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.96	-	-	-	-	-	0.96	1.24	1.19	1.24	1.20	0.97
Latin America	0.06	0.29	-	-	-	0.51	-	-	0.78	-	-	-	0.04	1.57	-	5.69	-	1.35	-	0.11	(0.21)	10.18	10.12	14.56	15.33	14.51	11.30
Israel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.46	-	-	-	-	-	0.46	0.28	0.13	0.12	1.56	2.11
Jordan	0.29	0.21	-	-	-	0.56	-	-	0.97	0.13	0.06	-	-	0.16	-	0.25	0.06	0.59	-	0.13	-	3.43	2.99	1.81	-	-	-
Kuwait	0.30	0.21	-	-	0.13	0.07	-	-	0.55	-	0.32	-	-	2.23	-	0.06	-	0.40	-	0.07	-	4.32	3.25	2.90	2.73	1.08	1.24
United Arab Emirates	0.20	0.64	0.07	-	-	0.14	0.06	-	0.34	0.06	0.13	-	-	0.19	-	0.06	-	0.27	-	0.06	-	2.23	2.93	2.03	1.39	0.41	-
Middle East	0.79	1.06	0.07	-	0.13	0.76	0.06	-	1.86	0.20	0.51	-	-	2.58	-	0.84	0.06	1.26	-	0.27	-	10.44	9.45	6.88	4.24	3.06	3.35
Canada	-	-	-	-	-	0.07	-	-	-	0.06	-	-	-	-	-	0.18	-	-	-	-	-	0.32	0.24	0.47	0.42	0.75	1.28
Mexico	-	-	-	-	-	0.06	0.19	-	1.10	-	-	-	0.36	-	-	0.31	-	2.92	-	-	-	4.94	4.14	5.13	6.87	5.97	3.55
United States	-	-	-	-	-	-	-	-	0.13	-	-	-	-	-	-	1.43	-	-	-	-	-	1.57	1.68	1.82	1.17	1.83	3.26
North America	-	-	-	-	-	0.13	0.19	-	1.23	0.06	-	-	0.36	-	-	1.93	-	2.92	-	-	-	6.83	6.06	7.43	8.47	8.54	8.09
2017 Exports	12.36	3.72	56.19	6.95	0.77	3.61	16.23	26.43	21.32	4.08	8.43	7.71	4.15	80.99	11.14	10.81	5.19	13.06	-	2.70	(2.70)	293.15					
2016 Exports	11.52	0.78	44.34	6.28	0.51	3.45	16.59	24.97	18.57	4.32	8.14	7.36	4.04	77.24	10.84	10.57	5.58	2.88	-	4.46	(4.46)		257.97				
2015 Exports	12.14	-	29.39	6.61	-	3.84	16.12	25.03	20.36	4.23	7.78	7.00	3.68	77.75	10.92	12.53	5.60	0.33	1.53	4.57	(4.57)			244.84			
2014 Exports	12.58	0.34	23.25	6.18	0.33	3.72	15.88	24.90	19.37	3.68	7.86	3.49	4.33	76.57	10.57	14.38	5.78	0.25	6.68	6.23	(6.23)				240.13		
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

Indonesia, Malaysia, India, France, and the UAE conducted domestic LNG trade in 2012-2017. These volumes are not included above as they do not reflect international trade between countries. Sources: IHS Markit, IGU

LNG continues to be used to increase gas supply security even in markets with ample pipeline connections. European importers such as France, Italy, and Turkey use LNG to diversify their import mix and to maintain access to gas in the case of inadequate pipeline flows. Countries with high renewables penetration in their power mixes are also considering gas, often delivered as LNG, as a source of reliable backup power generation to complement renewables. This is particularly the case in Brazil and Colombia, the latter of which was a new importer in 2016.

During the past decade, the fortunes of domestic gas production in several countries have, and will continue to affect their outlooks as importers. The most pronounced shift was the shale revolution in the US, which allowed the country to begin exporting LNG from the Lower 48, instead of becoming a net importer as had previously been projected. US production in turn influenced the LNG import needs of neighbouring Canada and Mexico as well. For other importers, such as Argentina, the possibility of expanding unconventional gas production is likely to change the dynamic of LNG imports in the future. The development of conventional gas resources is likely to play a key factor in LNG imports, potentially even eliminating the need for them, as could be the case in Egypt.

3.4. LNG Interregional Trade

The largest global LNG trade flow route continues to be intra-Pacific trade (see Figure 3.10), a trend that is unlikely to change in the near term given high demand growth in China, Southeast Asia, and South Asia and increasing supply from Australia. Trade between the Middle East and Pacific was the second-highest by volume, due to Qatar's role in supplying Japan, South Korea, and China. With better supply availability in the Pacific Basin, additional Atlantic Basin cargoes were free to remain within that basin. This fact, along with a recovery in European LNG demand, drove an increase of 12.8 MT in intra-Atlantic trade, as it remained the third largest trade route by volume.

Pacific Basin LNG has continued to stay within its own basin, with Pacific-Middle East and Pacific-Atlantic flows totalling just 3.8 MT in 2017, compared with 125.0 MT of Intra-Pacific trade. Moreover, the Pacific Basin attracted more LNG from the Atlantic Basin, largely the result of increased LNG production in the United States. Flows into the Middle East remain relatively small, with other Middle East and Atlantic Basin sources providing around 74% of those countries' imports.

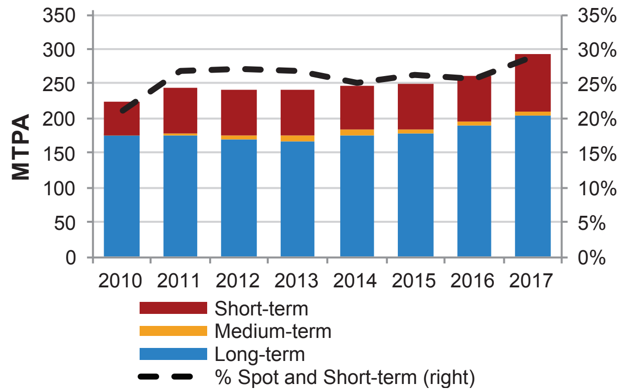
3.5. Spot-, Medium-, and Long-Term Trade[5]

Over the past decade, LNG trade has evolved from being traditionally delivered under long-term, fixed destination contracts as a growing number of cargoes have been sold under shorter contracts or on the spot market.

88.3 MT
Non long-term trade in 2017;
30% of total gross trade

This "non long-term" LNG trade[6] has been made possible by the emergence of portfolio players and traders, as well as more destination flexibility in contracts. The growth of non long-term trade

Figure 3.12: Short-, Medium-, and Long-Term Trade, 2010–2017



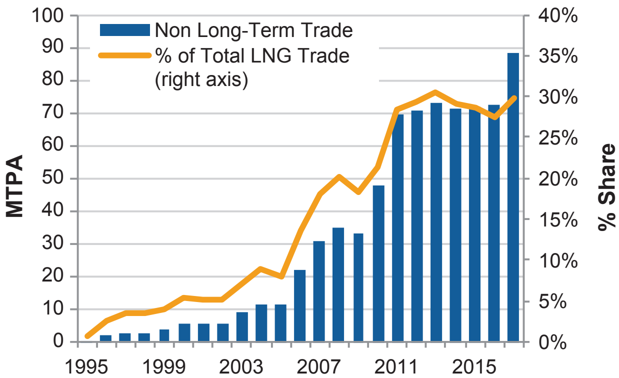
Sources: IHS Markit, IGU

accelerated in 2011 owing to shocks like those that resulted from the Fukushima crisis and the growth of shale gas in the United States, but stagnated through 2016 as new LNG supply came mostly from long-term contracted projects. However, the volume of LNG traded without a long-term contract increased significantly in 2017 (+21% YOY), owing partially to ramp-up at new flexibly-contracted liquefaction projects in the Atlantic Basin. Non long-term trade now accounts for nearly 30% of the LNG market – nearly double its share from a decade ago. Over the past decade, this segment of the market has developed as a result of several key factors:

- The growth in LNG contracts with destination flexibility, which has facilitated diversions to higher priced markets.
- The increase in the number of exporters and importers, which has amplified the complexity of the industry and introduced new permutations and linkages between buyers and sellers. In 2017, 29 countries (including re-exporters) exported spot volumes to 33 end-markets. This compares to 6 spot exporters and 8 spot importers in 2000.
- The growth of companies with diverse marketing portfolios taking on an aggregator role, allowing long-term offtake contracts to satisfy a variety of short- and long-term buyer commitments.
- 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 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 from 2010 to 2014, which made arbitrage an important and lucrative monetisation strategy.
- The faster development timeline and lower initial capital costs of FSRUs compared to onshore regasification, which allow new countries to enter the LNG market.
- The large growth in the LNG fleet, especially vessels ordered without a long-term charter, which has allowed for low-cost inter-basin deliveries.

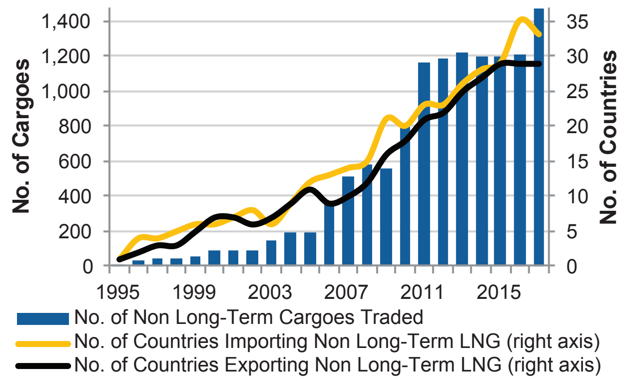
[5] As defined in Section 8.
[6] "Non long-term" trade refers to all volumes traded under contracts of less than 5 years duration (spot/short-term + medium-term trade). To truly capture the size of the market, volumes are considered non long-term if at any point they were traded under anything other than a long-term contract (e.g., volumes procured from the spot market but delivered under a long-term portfolio contract would be considered spot).

Figure 3.13: Non Long-Term Volumes, 1995–2017



Sources: IHS Markit, IGU

Figure 3.14: Non Long-Term Cargo Market Development, 1995–2017



Sources: IHS Markit, IGU

The vast majority of all volumes traded without a long-term contract are short-term trade – defined here as all volumes traded either on the spot market or under agreements of less than two years. In 2017, short-term trade reached 84.2 MT, or 28.7% of total gross traded LNG (including re-exports). This marks an all-time high for both the volume and share of short-term trade, and represents a 25% increase over 2016. Compared to new projects that started up in the Pacific Basin in 2016, which were largely contracted under long-term deals directly with end-users, new projects in the Atlantic Basin – including Sabine Pass LNG and Angola LNG – have signed a variety of short- and long-term deals, many with aggregator and trader companies, supporting the growth of short-term trade.

Volumes traded under medium-term contracts (between 2 and <5 years) remain a comparatively small portion of all non long-term trade. Medium-term deliveries declined for the third year in a row in 2017, falling from 4.7 MT in 2016 to 4.0 MT in 2017, as several contracts were filled increasingly with short-term volumes. Medium-term contracts offer countries with uncertain future LNG needs more security of supply for their minimum requirements than would be provided by short-term imports; and they have been favoured by buyers hesitant to sign long-term contracts because of the availability of uncontracted and flexible supply.

The total volume of all non long-term LNG trade reached 88.3 MT in 2017, an increase of 16 MT relative to the previous year. Non long-term trade accounted for 30% of total gross LNG trade – a 2% increase in share from 2016, and just 0.6 percentage points lower than the peak share that non long-term trade reached in 2013, when Japan was turning heavily to the spot market to satisfy its post-Fukushima needs. Given that the build-up of new long-term contracted capacity from the Pacific Basin will soon come to an end as the final Australian trains come online, while several large, flexibly-contracted projects in the United States have yet to begin exports, the share of non long-term LNG is likely to continue to increase in the near-term.

The largest growth in non long-term supply in 2017 came from the United States, where 69% of exports were traded on the non long-term market, while the remaining 31% were taken by the long-term offtakers to fulfill long-term market positions or delivered to their home markets. Ramp-up at Sabine Pass LNG – whose early trains are underpinned by flexible-destination contracts with aggregators – supported the growth of flexible deliveries, as US cargoes were sent to twenty-five different markets during the year. Non long-term supply from Angola LNG also grew, as the project signed several short-term deals with trader companies for its returning production growth of 2.9 MT. New capacity also combined with the expiration of older contracts to increase short-term trade, as in Malaysia, where short-term deliveries grew by 5.6 MT YOY.

Many of the countries with declines in non long-term supply also had a decline in total exports (or re-exports, in the case of many European countries), though the biggest decline came from Qatar. Non long-term deliveries from Qatar fell by 2.1 MT, as the startup of Asian contracts at new Australian projects led Qatari deliveries to pivot back to contracted positions in the Atlantic Basin, where several new contracts in Europe began in 2017.

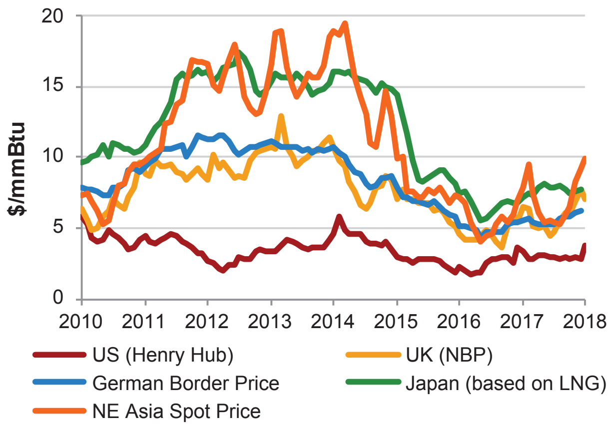
Mirroring the larger trend in total LNG trade, the market with the most non long-term growth in 2017 was China. While the country continued to receive a large number of cargoes under new long-term contracts, proactive efforts to meet anti-pollution measures by the end of the year led many Chinese buyers to search for additional short-term volumes, leading China's non long-term imports to grow by 4.7 MT. South Korea also relied on the spot market to supply much of its nuclear outage-related growth, with non long-term imports rising by 39% in 2017.

In a reversal of its position in 2016 (when it had the largest growth), Egypt had the largest non long-term decline in 2017, falling by 1.3 MT. Given that the market has relied on short- and medium-term contracts to fill its temporary LNG demand spike, Egypt's spot imports will continue to decline as new domestic gas production eliminates the need for LNG. Several of the other largest contractions in non long-term imports were the result of generally lower LNG demand, as in the United Arab Emirates and Argentina. Although India's total LNG imports grew by 1.5 MT YOY, the continued ramp-up of new long-term contracts led its short-term imports to fall by 5%.

3.6. LNG Pricing Overview

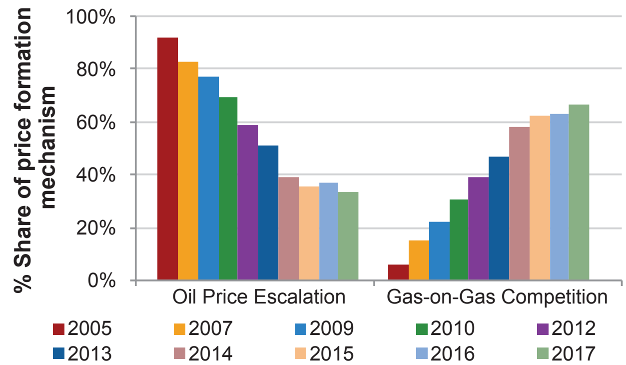
Trends in LNG-related prices followed many of the same patterns as in 2016, and were influenced by several of the same drivers of volatility, particularly in spot- or hub-based prices. Cold winter weather in Asia and Europe at both the beginning and end of the year influenced a run-up in spot prices on both continents, but increasingly plentiful supply in the summer led prices to dip significantly. Between February

Figure 3.15: Monthly Average Regional Gas Prices, 2010–January 2018



Sources: IHS Markit, Cedigaz, US DOE

Figure 3.16: European Import Price Formation, 2005 to 2017



Note: Oil Price Escalation = prices linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. Gas-on-Gas Competition = prices determined by the interplay of supply and demand – gas-on-gas competition – that are traded at physical or notional hubs.
Sources: IGU Wholesale Gas Price Survey – 2018 Edition

and August 2017, landed northeast Asian LNG spot prices fell by $4.21/MMBtu, only to rise by slightly more than that again by the end of the year, reaching an average $9.88/MMBtu in January 2018 – their highest point in three years. While this resurgence is notable, spot prices are likely to once again face downward pressure in the coming years as new liquefaction capacity is added, particularly during traditional seasonal lulls in demand in the spring and summer months.

The high prices at the end of 2017 have shown that seasonal tightness in the global LNG market is still very possible, particularly in the winter. For the second year in a row, Asian spot prices rose into the fourth quarter of the year, diverging from European prices and even rising above oil parity. As a response to the increased arbitrage, US LNG continued to flow to Asia. The delivered costs of US LNG provides an increasingly important reference point for global markets, given the flexibility of its destination-free supply as well as the liquidity and pricing transparency of the US market.

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 make use of gas 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, supplemented by a smaller share of spot imports.

Trends in oil prices are crucial indicators for the LNG market. Falling oil prices between late 2014 and mid-2016 led to a drop in traditionally oil-linked prices in Europe and Asia, but a recovery beginning in late-2016 has caused a turnaround. From an average of over $100/bbl in the first eight months of 2014, Brent crude prices fell rapidly to an average low of $44/bbl in 2016, but have since rebounded to an average $54/bbl in 2017. 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, only dropping to $9.77/MMBtu in 2015 and further to $6.59/MMBtu in 2016. The recovery in oil prices has begun to manifest itself in 2017 Japanese prices, with the average import price growing to $7.60/MMBtu.

Since the start of the decade, Asian buyers have increasingly sought to diversify the pricing structures of their LNG portfolios, shifting away from the traditional fixed-destination, long-term, oil-linked LNG contract. The sustained growth of shale gas production in North America has seen Henry Hub trade at a discount to other major gas benchmarks in the Pacific Basin and Europe, prompting Japanese, South Korean, Indian, and Indonesian companies, among others, to sign several offtake agreements based on Henry Hub linkage. However, as oil prices have declined, buyer contracting activity from the US has also waned.

There was significant oscillation in Northeast Asian spot LNG prices in 2017. After starting the year at $9.49/MMBtu in February, prices fell steadily in the first half of the year as the effects of cold winter demand waned, landing at a low of $5.28/MMBtu in August 2017. Notably, this price dip was not as pronounced as the previous year's low of $4.03/MMBtu reached in May 2016, as strong Chinese and South Korean off-season demand in 2017 supported slightly higher prices. Prices rose again as the 2017–2018 winter ushered in more cold weather, with spot prices reaching a three-year high in January 2018 at $9.88/MMBtu.

Since 2009, European gas contracts have increasingly been signed or renegotiated to include hub gas price indexation (particularly in the Northwest), dropping the historically dominant links to crude and fuel oil. Due to European Union energy policies and market dynamics, major gas suppliers have since increased the share of hub pricing in the formulation of pipeline export prices for certain contracts.

Like contracted Japanese LNG prices, the German border gas price – a proxy for contracted European gas import prices – has followed the fall and rise in oil prices throughout the last three years, with a slight lag owing to delayed contract linkages. German prices began to reflect the fall in oil prices in 2015, averaging $6.80/MMBtu for the year and falling to $4.93/MMBtu during 2016. They have since recovered to an average $5.62/MMBtu in 2017, though increased indexation to hub prices has begun to contribute to lower border prices.

Spot prices in Europe have shown similar patterns of variability as those in Asia, though with more muted peaks. From mid-2014 to mid-2016, low oil prices pulled prices at European gas hubs down, coupled with weak power demand and weather fundamentals. By end-2016, spot prices had risen along with global trends, also influenced by the Rough storage outage in the UK, hitting $6.54/MMBtu by January 2017. The influence of additional supply led NBP to weaken to a low of $4.46/MMBtu by June, but tightness in the LNG market created by Asian spot buying, along with a colder than average December, led NBP to climb back to $7.76/MMBtu in December 2017. If LNG imports into the European continent increase substantially in the short run, it will put downward pressure on the UK NBP in the coming years, though continued seasonal variation can be expected.

Since the 2014 drop in oil prices, LNG prices around the world have moved closer to convergence, though upward movements in 2017 have widened differentials slightly. Between Asia and Europe, the differential between spot prices became slightly negative once again during the summer as it had in 2016, with northeast Asia spot prices at an average $0.18/MMBtu discount to NBP in August and September. By January, however, the differential had risen to $2.91/MMBtu.

After the differential between NBP and Henry Hub dropped to a low of $0.71/MMBtu in September 2016, it widened considerably during the winters of 2016–17 and 2017–18, reaching $4.96/MMBtu by December.

Gas price movements in North America are driven more by overall market fundamentals than by changes in the oil price. Compared to prices in other regions, Henry Hub prices were remarkably consistent through 2017, ranging only $0.50/MMBtu during the year. Annual prices averaged $2.96/MMBtu, an increase of $0.48/MMBtu over 2016. Downward price pressure at Henry Hub will come from removing infrastructure constraints in the Marcellus and Utica shales, opening supply to the market. In addition, end-market fuel competition with coal and renewables in the power sector will provide an upside limit.

Lower oil prices may have decreased the spread between oil-linked and US LNG contracts in the near-term, but the lower starting point of US prices and abundant resource mean that US LNG contracts may offer buyers reduced price volatility over the next few years.

Looking Ahead

Will demand uncertainty in the biggest LNG import markets continue? The onset of oversupplied conditions has been delayed by a cold winter in Asia and continuing uncertainty in the power markets of some of the biggest LNG importers, including Japan and South Korea. The pace and extent of nuclear restarts in Japan continue to be hard to predict, and another court injunction against the operation of a restarted reactor in late 2017 highlights the ongoing uncertainty in the market. However, the unusually high levels of nuclear maintenance in South Korea that supported increased imports in 2017 should be resolved in 2018, which could lead more LNG to flow to Northwest Europe.

How much will new domestic gas production influence LNG imports? Of the five markets to see a YOY contraction in LNG imports in 2017, two – Egypt and Argentina – were the direct result of new or improved domestic gas production. Egypt is particularly notable, as it was one of the largest growth markets in 2016. Egypt's government has expressed a desire to end LNG imports entirely by the end of 2018 or even earlier. Whether it can become self-sufficient depends on the further success of its fast-track development of the giant Zohr field, reaching plateau production nearly a year ahead of schedule in early 2019. While this is ambitious, the country has recently exceeded both schedule and output expectations at the Nooros, Atoll, and West Nile Delta fields; and if it reaches another bold target at Zohr, LNG imports in the market could drop significantly in 2018. In Argentina, the government renewed a program in Q1 2017 aimed to improve output from tight and shale gas resources by increasing wellhead prices. If this continues to lead to higher domestic production (as it did in 2017), LNG could get increasingly displaced in Argentina's near-term gas mix.

Gorgon – Courtesy of Chevron

4. Liquefaction Plants

Significant liquefaction capacity growth began in 2016 and has continued through 2017 and early 2018. As of March 2018, global nominal[1] liquefaction capacity totalled 369.4 MTPA, an increase of 32.2 MTPA from the end of 2016[2]. In an important milestone, the first exports from a floating LNG (FLNG) project commenced in 2017, and several more FLNG projects are scheduled to start up in 2018. Capacity under construction totalled 92 MTPA as of March 2018. Most of the current liquefaction buildout, led by Australia and the United States, is expected to be completed by 2020.

Approximately 875 MTPA of proposed capacity is targeting a subsequent phase of growth starting in the 2020s. This has created a highly competitive environment for new liquefaction capacity given supply/demand trends. Liquefaction investment has been muted over the past two years owing to low commodity prices and associated budgetary constraints, demand uncertainty, and anticipation of an LNG surplus. Developers of new projects are competing not only amongst each other but also with multiple existing projects considering potentially low-cost expansions and backfill opportunities. Qatar, for instance, plans to increase capacity from 77 to 100 MTPA by the mid-2020s. To secure customers, project sponsors are focused on reducing costs. Several long-term LNG contracts associated with new liquefaction capacity have been signed so far in 2018, but the extent to which they translate into final investment decisions this year remains to be seen.

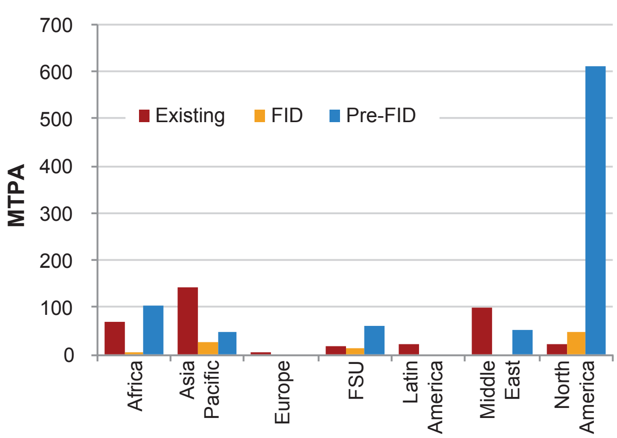
4.1. Overview

369.4 MTPA
Global nominal liquefaction capacity, March 2018

Nominal liquefaction capacity grew by 7% in 2017 and totalled 359.5 MTPA at the end of the year. Additional trains at several projects commenced commercial operations during 2017, adding 22.3 MTPA of nominal capacity. Growth came primarily from Australia and the US, as Australia Pacific LNG T2 (4.5 MTPA) and Gorgon LNG T3 (5.2 MTPA) in Australia as well as Sabine Pass LNG T3-4 (9 MTPA) in the US began operations. A ninth train at Malaysia LNG (3.6 MTPA) also entered the commercial operations phase. Capacity had increased to 369.4 MTPA as of March 2018 following the start of commercial operations at Wheatstone LNG (4.45 MTPA) in Australia and Yamal LNG (5.5 MTPA) in Russia (see Figure 4.1).

The significant liquefaction capacity expansion that started in 2016-2017 will continue in 2018 as more trains that were sanctioned several years ago come online. Wheatstone LNG T1 in Australia (4.45 MTPA) and Yamal LNG T1 in Russia (5.5 MTPA) shipped their first cargoes in 2017 and are assumed to have begun commercial operations in March 2018. Out of 92 MTPA of under-construction capacity, project sponsors expect more than one-third (33.3 MTPA) to come online later this year in Australia, Cameroon, Indonesia, Malaysia, Russia, and the US. This includes PFLNG Satu in Malaysia (1.2 MTPA), which exported its first cargoes in 2017. A total of 43.2 MTPA of new project capacity is expected in 2018.

Figure 4.1: Nominal Liquefaction Capacity by Status and Region, March 2018



Note: "FID" does not include capacity stated to be under construction in Iran. For the purposes of this report, it is included under "pre-FID" capacity.
Sources: IHS Markit, Company Announcements

Australia and the US have been the primary drivers of this phase of capacity growth and account for more than 70% of under-construction capacity. The pace of liquefaction investment continued to slow in 2017, with only one project – Coral South FLNG in Mozambique (3.4 MTPA) – reaching a final investment decision (FID) and beginning construction.

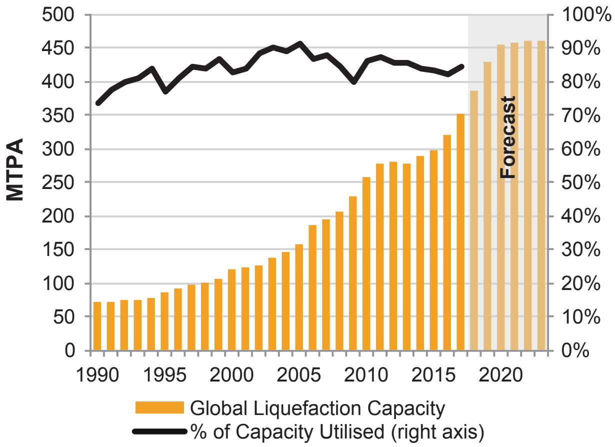
92 MTPA
Global liquefaction capacity under construction, March 2018

There is a large amount of proposed capacity (875.5 MTPA as of March 2018), much of which is aspiring to come online in the 2020s, when sponsors anticipate new supply will be required. Proposals are spread across the globe, but the US and Canada account for more than two-thirds (591 MTPA) of pre-FID capacity. Major new liquefaction capacity is also planned for Sub-Saharan Africa, Russia, Qatar, and Papua New Guinea. The development of many proposals has proceeded relatively slowly. Approximately 44% of proposed capacity is estimated to have entered at least the pre-front end engineering and design (pre-FEED) phase.

Projects planning to reach an FID in the near term are competing for customers willing to sign foundational contracts ahead of the large near-term buildup in supply, leading to a general slowdown in contracting activity over the last several years. Demand uncertainty, capital budget constraints, and a desire for shorter-term contracts are challenges facing project sponsors, many of which are emphasising their cost structures and location-specific advantages in an attempt to move forward.

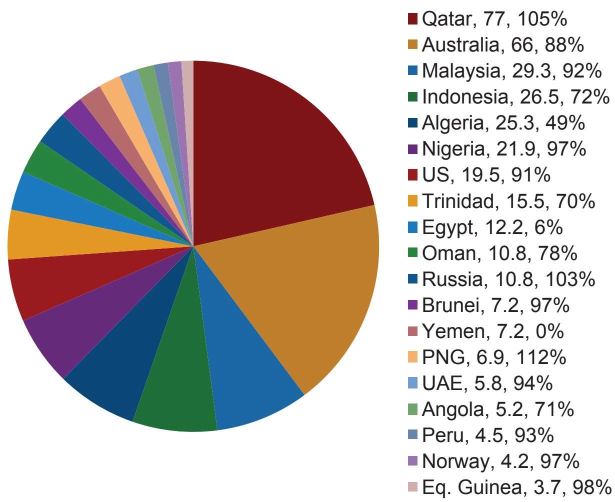
[1] Nominal liquefaction capacity refers to projects' nameplate capacities and is not prorated based on project start dates.
[2] Some individual capacity numbers have been restated over the past year owing to improved data availability. This may cause global capacity totals to differ compared to the IGU World LNG Report - 2017 Edition.

Figure 4.2: Global Liquefaction Capacity Build-Out, 1990–2023



Sources: IHS Markit, Company Announcements

Figure 4.3: Nominal Liquefaction Capacity and Utilisation by Country, 2017[3]



Sources: IHS Markit, IGU

4.2. Global Liquefaction Capacity and Utilisation

In 2017, global liquefaction capacity utilisation was 84%. This represented an increase from 82% in 2016 and reversed several years of declines (see Figure 4.2).

Most existing projects were highly utilised. Brunei, Equatorial Guinea, Nigeria, Norway, Papua New Guinea, Qatar, Russia, and the UAE operated at or near nameplate capacity levels, and utilisation increased at several recently commissioned or restarted projects as exports ramped up.

Exports from Gorgon LNG in Australia and Sabine Pass LNG in the US were the largest incremental supply sources globally as new trains started operations and initial trains had their first full year of exports. Angola LNG returned to operations in 2016 after several years of extended repairs; the project achieved greater production consistency in 2017 and secured several short-term sales contracts for its output on a forward basis.

Utilisation also improved at several projects facing feedstock availability challenges. In Algeria, lower pipeline exports to southern Europe during the summer enabled more gas to be exported as LNG, while in Trinidad several upstream projects began operations during 2017. However, Bontang LNG in Indonesia continues to face feedstock challenges, with LNG exports falling during the year. There were also reductions in utilisation across projects in Australia. Coalbed methane (CBM)-based LNG projects continue to face gas supply challenges, and there has been political pressure to supply more gas to the domestic market owing to high prices.

Several existing projects did not export cargoes in 2017. In Egypt, SEGAS LNG has not exported a cargo since 2012, and Egyptian LNG only exported a few due to feedstock constraints. Production at Yemen LNG was halted in 2015, and the project remained offline through March 2018 amid an ongoing civil war. Kenai LNG in Alaska did not export cargoes in 2016 or 2017 due to feedstock constraints and market conditions. The project was placed in preservation mode in fall 2017 and in January 2018 was acquired by the owner of a nearby refinery.

4.3. Liquefaction Capacity by Country

Existing

There were 19 countries with liquefaction capacity[4] as of March 2018 (see Figure 4.3). The newest country to become an LNG exporter is Papua New Guinea, which commenced exports from PNG LNG in 2014, though the startup of exports from Sabine Pass LNG in 2016 marked the first LNG produced in the continental United States.

Liquefaction capacity is concentrated in Qatar, Australia, Malaysia, Indonesia, Algeria, and Nigeria, each of which has at least 20 MTPA of capacity. Together, these six countries comprised more than two-thirds of the world's nominal liquefaction capacity in 2017. Qatar remained the world's largest source of liquefaction capacity with 77 MTPA, or more than one-fifth of the world total, followed by Australia with 66 MTPA as additional trains came online.

+28% by 2023
Expected growth in global nominal liquefaction capacity

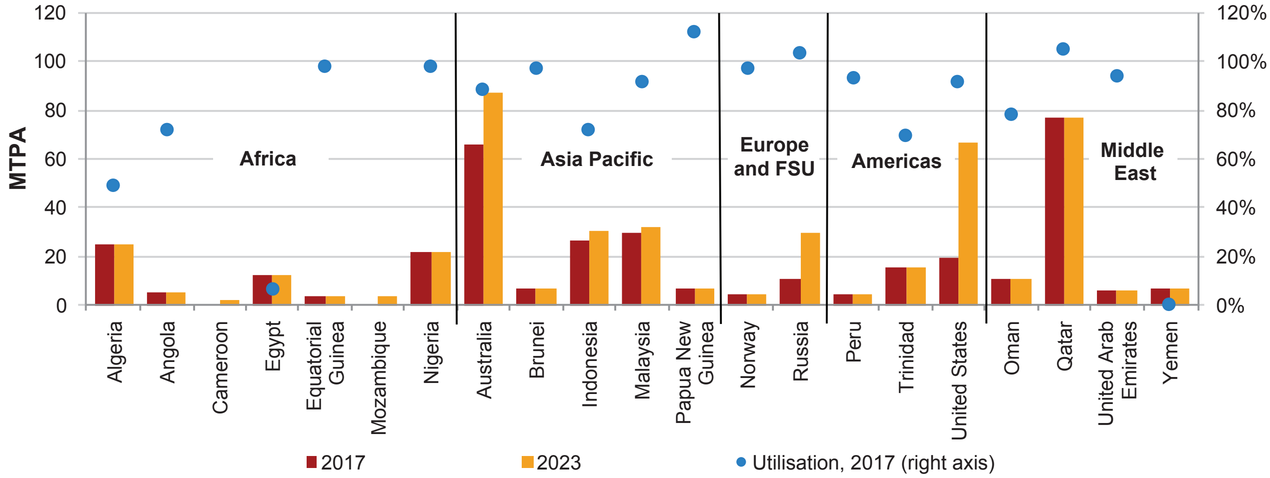
Under Construction

92 MTPA of liquefaction capacity was under construction as of March 2018, including several projects – PFLNG Satu, Cove Point LNG, and Kribi FLNG (in Cameroon) – that have shipped or are soon expected to ship commissioning cargoes and begin commercial operations in early 2018. More than half (48.6 MTPA) of under-construction capacity is now in the US, while Australia's share (17 MTPA) has fallen as the country brings more trains online. As its remaining under-construction trains – Wheatstone LNG T2 (4.45 MTPA), Ichthys LNG T1-2 (8.9 MTPA), and Prelude FLNG (3.6 MTPA) – are expected to come online this year, Australia is expected to surpass Qatar as the largest source of liquefaction capacity. There is additional under-construction capacity in Russia (13.7 MTPA), Indonesia (4.3 MTPA), Mozambique (3.4 MTPA), Malaysia (2.7 MTPA), and Cameroon (2.4 MTPA).

[3] Utilisation is calculated based on prorated capacity.

[4] Includes Yemen, which did not export cargoes in 2016-2017. Although the US has exported from Kenai LNG in Alaska, the continental US began exporting in 2016 (not including re-exports). Projects in the continental US are utilising a different resource base.

Figure 4.4: Nominal Liquefaction Capacity by Country in 2017 and 2023



Note: Liquefaction capacity only includes existing and under-construction projects expected online by 2023. Sources: IHS Markit, IGU, Company Announcements

With six projects totalling 48.6 MTPA under construction on the Gulf and East coasts, the US will be the largest source of incremental liquefaction capacity through 2023 (see Figure 4.4). Apart from Corpus Christi LNG, sanctioned US LNG projects are brownfield developments associated with existing regasification terminals. As of March 2018, four trains were operational at Sabine Pass LNG, which in 2016 became the first project to export LNG (not including re-exports) from the continental US. Cove Point LNG also exported its first cargo during the month. Project sponsors anticipate adding 6.8 MTPA of capacity in 2018 at Cove Point LNG and Elba Island LNG Phase 1, with the remaining sanctioned trains (41.8 MTPA) expected online in 2019 and 2020.

Yamal LNG in Russia began exporting commissioning cargoes in late 2017, with tankers delivering volumes to Northwest Europe for transhipment to other markets. Novatek is assumed to have begun commercial operations in Q1 2018 and anticipates the project will be fully online in 2019.

Proposed

With pre-FID liquefaction capacity totalling approximately 875.5 MTPA as of March 2018, there is a variety of supply options globally. However, uncertainty regarding LNG demand and the extent of the near-term supply buildup, along with the large number of proposals, has made it challenging for many projects to secure offtakers.

More than two-thirds of proposed capacity is located in the US (336 MTPA) and Canada (255 MTPA). In the US, most projects are located on the Gulf Coast and will source gas from a variety of supply basins, while the approximately 20 MTPA Alaska LNG project is intended to commercialise stranded North Slope gas. The project, which would require an approximately 800-mile long pipeline, signed a non-binding Joint Development Agreement with Chinese counterparties in 2017 and is aiming to reach an FID next year.

In Canada, most projects are located in British Columbia on the West Coast and will source feedstock from the Western Canadian Sedimentary Basin (WCSB). Development of Canadian LNG has yet to materialise. High capital cost estimates and the need for lengthy greenfield pipelines to connect upstream resources to remote project sites, along with market conditions, were factors in the cancellation of several projects in 2017. In Eastern Canada, pipeline capacity will need to be expanded and reversed. As momentum at some West Coast projects has slowed, several East Coast projects are also proposing to source gas from Western Canadian producers.

Following Yamal LNG, a key component of Russia's ambitious LNG expansion plans is to commercialise stranded Arctic gas based on indigenously produced components, with a goal of reducing costs. Such an approach may also mitigate the impact of potential future sanctions. Russia is proposing 60.1 MTPA of new liquefaction capacity across the country. Yamal LNG operator Novatek has proposed a fourth, smaller train at Yamal LNG, which it expects to bring online in 2019. Additionally, Arctic LNG-2 (19.8 MTPA) will be located nearby to Yamal LNG and plans to utilise three gravity-based structures, which Novatek hopes will provide cost savings. Other proposals include a third 5.4 MTPA train at the existing Sakhalin-2 project on the Pacific coast, and the 10 MTPA Baltic LNG project on the Baltic Sea, which are projected to come online in the 2020s.

The FID of Coral South FLNG (3.4 MTPA) in Mozambique in 2017 was the first in a series of projects aiming to commercialise large gas discoveries offshore East Africa. Proposed liquefaction capacity totalled 50 MTPA in Mozambique and 20 MTPA in Tanzania as of March 2018. Project sponsors plan to bring most of these proposals online in the 2020s. The Mozambique LNG (Area 1) project (12 MTPA) received government approval in March 2018 and is aiming to reach an FID once marketing and financing are completed. In West Africa, Nigeria LNG has proposed two expansion trains totalling 7.2 MTPA, while the Fortuna FLNG project in Equatorial Guinea is targeting an FID this year. Newer gas finds offshore Mauritania and Senegal have spurred several liquefaction proposals, including a cross-border FLNG development, Greater Tortue FLNG (4.6 MTPA across two FLNG units).

There are also a number of proposals to backfill existing liquefaction plants with new feedstock sources and/or expand capacity, which are an additional source of competition for new trains. In some cases these proposals have replaced standalone liquefaction projects, such as the Browse FLNG project in Australia, the feedstock for which is now proposed to supply North West Shelf LNG. Potentially lower costs may enable existing projects to offer more flexible contract terms to customers. The largest expansion is in Qatar as the country seeks to maintain its leading LNG supply position. In 2017, Qatar announced it would lift a moratorium on new production at the North Field and plans to increase liquefaction capacity from 77 to 100 MTPA by the mid-2020s. This would be accomplished through three new megatrains, with FIDs scheduled in 2019 or 2020. First LNG is expected in 2023. While there has been progress at a number of developments, challenges remain, including political risk (e.g., supply of Venezuelan or cross-border feedstock to Atlantic LNG in Trinidad), the need for lengthy pipelines (e.g., supply of Browse or Scarborough feedstock to projects in Australia), and the ability to conclude commercial agreements among upstream and liquefaction partners.

Decommissioned

The last formal decommissioning was Arun LNG in Indonesia in late 2014, which transitioned to a regasification terminal in early 2015. Only a few trains are likely to come offline in the near term. With declining feedstock availability, Kenai LNG in Alaska has not exported cargoes since 2015. The plant was placed into preservation mode in fall 2017 and sold to refiner Andeavor in January 2018, which intends to integrate the plant with its nearby refinery. It is therefore uncertain whether LNG exports will resume. Additional decommissioning may occur as trains at Arzew LNG in Algeria, Bontang LNG in Indonesia, and ADGAS in the United Arab Emirates age, feedstock production declines, and domestic gas demand grows.

In some instances, improved upstream production is expected to support continued LNG exports. In Egypt, plateauing domestic gas production and growing domestic gas demand has led the country to become a net LNG importer. SEGAS LNG has been idled since 2012, and Egyptian LNG resumed sporadic exports in 2016 after being idled in 2014. Several large upstream projects, including West Nile Delta, Zohr, and Atoll began production in 2017 and early 2018. Egypt intends to direct most production to the domestic market to enable it to return to gas self-sufficiency and cease LNG imports by the end of 2018. The potential to monetise gas from Cyprus and/or Israel via Egypt could facilitate a return to exports on a larger scale. In Oman, the start of production at the Khazzan tight gas field in 2017 may prolong exports from Oman LNG. Discussions have also continued regarding a potential gas supply agreement with Iran, which may backfill a portion of the plant, though the pipeline would need to be rerouted to bypass the UAE's Exclusive Economic Zone. Oman LNG was previously expected to stop exports in 2025.

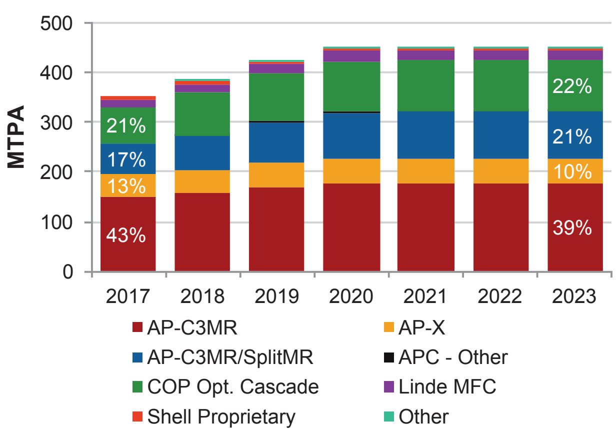
4.4. Liquefaction Processes

Air Products liquefaction processes accounted for 73% of global liquefaction capacity in 2017 (see Figure 4.5). Of this, the AP-C3MR™ remained the most widely used process at 43%, followed by the AP-C3MR/SplitMR® (17%) and AP-X® (13%) processes. Air Products processes are also being used in more than two-thirds of under-construction capacity. Cameron LNG in the US and Yamal LNG in Russia have selected the AP-C3MR™ design, while Cove Point LNG and Freeport LNG in the US, Tangguh LNG T3 in Indonesia, and Ichthys LNG in Australia will use the AP-C3MR/SplitMR® process. The AP-X® process has only been used in Qatar. As Qatar pursues its liquefaction capacity expansion plans, it is unclear whether the process will be used in the new megatrains.

Air Products technology has been incorporated into most sanctioned FLNG projects to date. Air Products provided the cryogenic heat exchanger for Prelude FLNG. The AP-N™ process was used for PFLNG Satu and PFLNG Dua, and the AP-DMR™ process was selected for Coral South FLNG. At Kribi FLNG in Cameroon, however, the Black & Veatch PRICO® process was selected.

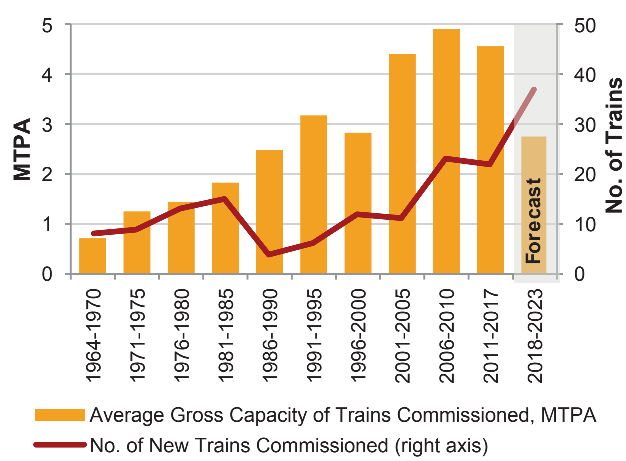
With Australia and the US accounting for most new trains and under-construction capacity, the market share of the ConocoPhillips Optimized Cascade® process is increasing given its suitability to dry gas. The two countries account for nearly 70% of the technology's deployment in existing and

Figure 4.5: Liquefaction Capacity by Type of Process, 2017–2023



Source: IHS Markit

Figure 4.6: Number of Trains Commissioned vs. Average Train Capacity, 1964–2023



Sources: IHS Markit, Company Announcements

under-construction projects, and all three of the CBM projects in Eastern Australia utilise the process. Optimized Cascade® accounted for more than 60% of capacity that came online in 2017. By 2023, the process is expected to be used in 22% of global capacity, based on currently sanctioned projects.

An increasing number of liquefaction proposals are being developed with smaller trains and/or a modular design, with the intent of reducing costs through greater offsite construction (see Figure 4.6). Smaller trains also reduce the amount of volumes that need to be contracted prior to reaching an FID. A number of projects in North America plan to utilise processes geared towards smaller capacities, including IPSMR® (Chart Industries), OSMR® (LNG Limited), PRICO® (Black & Veatch), and the Movable Modular Liquefaction System (MMLS) [Shell]. In Russia, Novatek has developed the proprietary Arctic Cascade process, which it plans to use for a smaller 0.9 MTPA expansion train at Yamal LNG.

4.5. Floating Liquefaction

180.5 MTPA
Proposed FLNG capacity, March 2018[5]

In a significant milestone for the LNG industry, the first FLNG project – PFLNG Satu in Malaysia (1.2 MTPA) – began exports in 2017. Additional sanctioned FLNG capacity in Australia, Cameroon, Malaysia, and Mozambique totaling 10.9 MTPA is anticipated to start up between 2018 and 2022.

As of March 2018, 180.5 MTPA of FLNG capacity has been proposed across 24 projects. Nearly 80% of this capacity is located in Canada (74.4 MTPA) and the US (69 MTPA), with other proposals located in Australia, Republic of the Congo, Djibouti, Equatorial Guinea, Indonesia, Iran, Mauritania, Mozambique, Papua New Guinea, Russia, and Senegal (see Figure 4.7).

FLNG projects located offshore, which can utilise either purpose-built or converted vessels, enable the commercialisation of stranded gas resources, while near- or at-shore barge solutions have reduced onshore infrastructure and are generally planned to be supplied from onshore resources.

FLNG projects tend to be smaller in capacity than their onshore counterparts, which may allow buyers with smaller offtake needs to underpin a project, though a few larger-scale FLNG projects have been proposed.

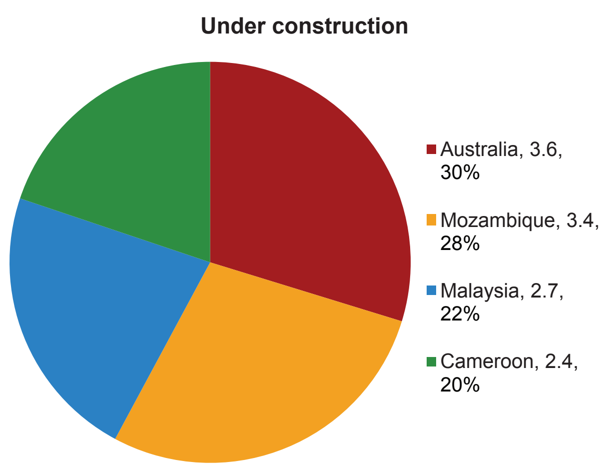
FLNG projects seek to optimise costs through a greater proportion of offsite construction, and some reportedly have lower cost estimates than land-based. Greater certainty around costs will be established as more projects come online and develop a track record of performance. Like any liquefaction project, especially those based on new development concepts, there exists the possibility of design and cost escalation.

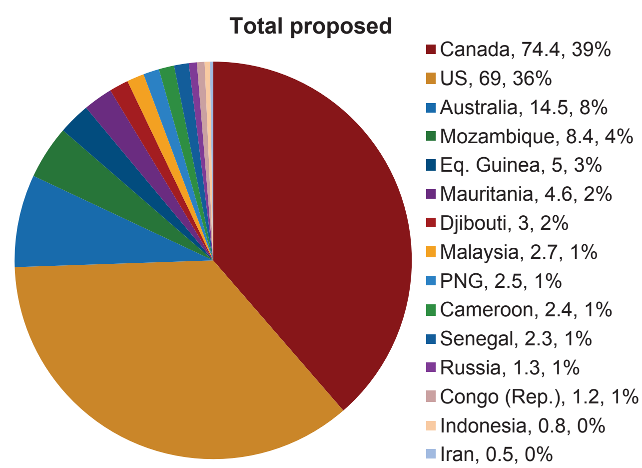
Including PFLNG Satu, four of the five under-construction FLNG projects are using purpose-built vessels. Prelude FLNG was towed to its site offshore Australia in mid-2017 to begin the hook-up and commissioning process. The project is expected online in 2018. Construction at PFLNG Dua was placed on hold in 2016, with the project currently scheduled for a start-up in 2020. Coral South FLNG in Mozambique reached an FID in June 2017, the only project to be sanctioned last year. Operator Eni expects the project online in 2022.

The first FLNG conversion scheme to reach an FID was Kribi FLNG in 2015. The vessel arrived on site in Cameroon in November 2017; it is currently undergoing commissioning activities. An LNG tanker arrived in late February, and first exports are expected in April. Fortuna FLNG in Equatorial Guinea, also a conversion project, is planning to reach an FID in 2018 once financing is completed. In 2017, Gunvor was selected to offtake 2.2 MTPA from the project for ten years.

Approximately 40 Tcf of gas resources have been discovered between Mauritania and Senegal over the past several years, which has led multiple FLNG and potentially onshore projects to be proposed. Greater Tortue FLNG plans to commercialise the 15 Tcf Ahmeyim/Guembeul offshore field that straddles both countries via two 2.3 MTPA FLNG units, with the first announced to start up in 2021. Greater Tortue FLNG is currently considering an FLNG conversion scheme, but it is also possible that the project could use purpose-built vessels. Further FLNG vessels or an onshore project could be used to commercialise additional resources. Alignment between Mauritania and

Figure 4.7: Under Construction and Total Proposed FLNG Capacity by Country in MTPA and Share of Total, March 2018

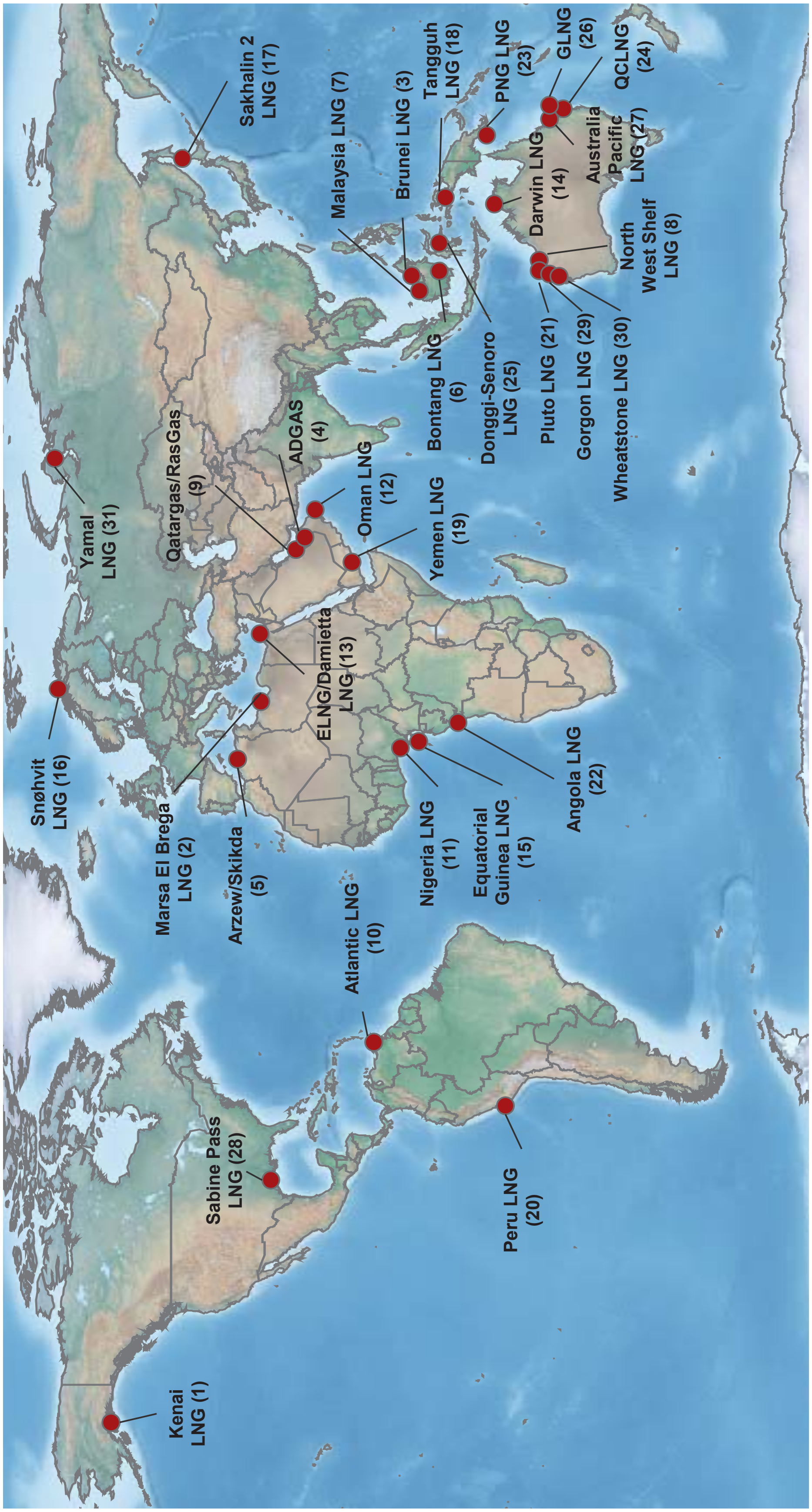




Notes: "Total proposed" capacity is inclusive of under-construction capacity. Source: IHS Markit

[5] This number is included in the 875.5 MTPA of total proposed global liquefaction capacity quoted in Section 4.1. It excludes the 12.1 MTPA of FLNG capacity currently under construction..

Figure 4.8: Global Liquefaction Plants, March 2018



Source: IHS Markit

2016–2017 Liquefaction in Review

Capacity Additions	New LNG Exporters	US Build-out Continues	Floating Liquefaction
+22.3 MTPA Year-over-year growth of global nominal liquefaction capacity in 2017 **+10 MTPA** New nominal capacity added in Q1 2018	**0** Number of new LNG exporters in 2017	**18 MTPA** Continental US capacity online as of March 2018	**12.1 MTPA** FLNG capacity under construction as of March 2018
Nominal liquefaction capacity increased from 337.2 MTPA in 2016 to 359.5 MTPA in 2017 92 MTPA was under construction as of March 2018 875.5MTPA of new liquefaction projects have been proposed as of March 2018, primarily in North America. Qatar has proposed a major capacity expansion	The last country to join the list of LNG exporters was PNG in 2014 A number of new exporters could emerge in the coming years with proposals in emerging regions such as Canada and Sub-Saharan Africa; at least two of these new markets (Cameroon and Mozambique) have under-construction capacity	Previously expected to be one of the largest LNG importers, 48.6 MTPA of liquefaction capacity was under construction in the US as of March 2018 336 MTPA of US capacity was proposed as of March 2018, with many seeking to be part of a “second wave” of US LNG in the 2020s	The first exports from an FLNG project, PFLNG Satu, commenced in 2017 Five FLNG projects have reached an FID, with Coral South FLNG the only LNG project to be sanctioned in 2017 180.5 MTPA of floating liquefaction capacity has been proposed as of March 2018

Senegal is necessary for the project to proceed, and to that end a unitisation agreement was signed in February 2018. While the cross-border nature of the project adds complexity, there is partial precedent with Darwin LNG in Australia, which sources feedstock from the Joint Petroleum Development Area shared between Australia and Timor-Leste, though the liquefaction facility is located entirely within Australia.

Several barge-based projects are under consideration. In Canada, the Kwispaa FLNG project plans to utilise an at-shore development scheme, with operations proposed to commence in 2024. As of January 2018, Exmar was continuing to seek employment for two FLNG barges previously associated with the Caribbean FLNG project offshore Colombia (originally slated to be the first operational FLNG project) and the Douglas Channel FLNG project in Canada. Both projects were scrapped in 2016. Iran had been discussed as a possible destination for the Caribbean FLNG barge, but the Iran FLNG project had been placed on hold as of early 2018.

4.6. Project Capital Expenditures (CAPEX)[6]

Liquefaction costs vary across projects but have, on average, risen significantly over the last decade. Several projects have seen cost increases of 30–50% over estimates at FID. With numerous projects reaching FID in a similar timeframe, demand for engineering, procurement and construction (EPC) services led to elevated input and labour costs. Construction delays have also impacted costs. Australia has been particularly affected owing in part to exchange rate shifts, the availability of skilled labour, and project definition at the time of FID.

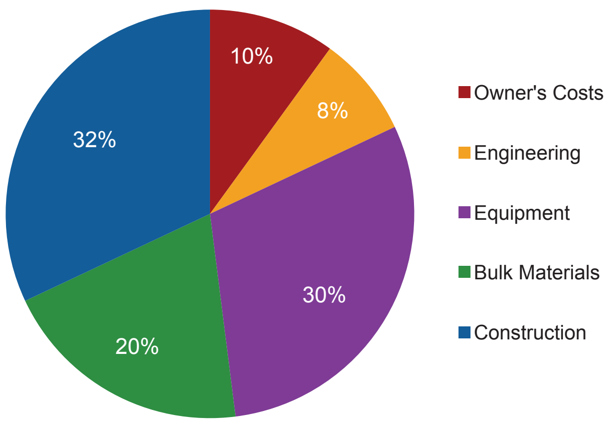
Factors in determining liquefaction costs include a project’s location, capacity, liquefaction process and choice of compressor driver, storage, skilled labour availability, and regulatory and permitting requirements. Bulk materials including steel and cement are large components of costs across projects, while gas processing needs will vary based on the upstream resource. The dry gas most US projects will source, for example, will limit the need for gas treatment infrastructure, which typically includes acid gas, natural gas liquids (NGL), and mercury removal in addition to dehydration. See Figures 4.8 and 4.9 for cost breakdowns by construction component and expense category.

Average liquefaction unit costs grew to $1,005/tonne in 2009–2017 versus $404/tonne in 2000–2008. The vast majority of the increase came from greenfield projects, which rose from $527/tonne to $1,501/tonne over the same period. At brownfield projects, which benefit from existing infrastructure, liquefaction unit costs averaged $458/tonne in 2009–2017 versus $321/tonne in 2000–2008. Additional clarity with respect to FLNG costs is likely as construction progresses and commercial operations begin at several projects in 2018. Those based on vessel conversions – such as Kribi FLNG in the Atlantic Basin – have typically quoted lower costs relative to purpose-built FLNG and in some cases onshore greenfield proposals (see Figure 4.10).

Projects in the Pacific Basin have had the highest amount of cost increases. Liquefaction unit costs averaged $1,458/tonne in 2009–2017, more than quadrupling from the 2000-2008 period.

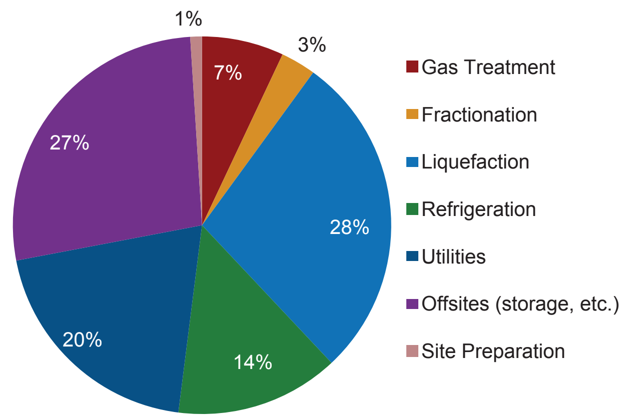
[6] CAPEX figures reflect the complete cost of building the liquefaction facilities, including site preparation, gas processing, liquefaction, LNG storage, and other related infrastructure costs. Upstream and financing costs are excluded.

Figure 4.8: Average Cost Breakdown of Liquefaction Project by Construction Component[7]



Source: Oxford Institute for Energy Studies

Figure 4.9: Average Cost Breakdown of Liquefaction Project by Expense Category



Source: Oxford Institute for Energy Studies

Atlantic Basin projects experienced somewhat smaller but still notable growth in liquefaction costs, averaging $1,011/tonne in 2009–2017 versus $480/tonne in 2000–2008. Lower-cost brownfield expansions in Qatar enabled average liquefaction costs in the Middle East to remain low during 2009–2017 at $385/tonne, up slightly from $299/tonne in the 2000–2008 period (see Figure 4.11).

In a highly competitive market, there has been considerable impetus for project sponsors to reduce costs to reach FID during a period of significant capacity buildup. Technological advancements have enhanced well productivity to reduce upstream costs, while there has been downward pressure on liquefaction EPC costs and increased optimisation efforts. US projects have generally signed lump-sum EPC contracts, which mitigate some of the risk to the sponsor of cost overruns, as opposed to the cost-plus contracts used for some projects elsewhere.

Achieving lower costs will help project sponsors meet the needs of an increasingly diverse set of buyers. As some customers seek alternative pricing structures and/or shorter contract terms, lower-cost projects – both new trains and expansions or backfills of existing projects – may have more flexibility in marketing and financing. Conversely, more complex projects, such as those requiring lengthy pipeline infrastructure or difficult upstream development, may find it more difficult to be competitive.

4.7. Risks to Project Development

There are a variety of commercial, political, regulatory, and macroeconomic risks faced by liquefaction projects both before and following an FID. In some cases, these risks are similar to those of other large infrastructure projects and can slow the pace of project development. Key risks for liquefaction projects include project economics, politics and geopolitics, environmental regulation, partner priorities and ability to execute, business cycles, feedstock availability, domestic gas needs, fuel competition, and marketing and contracting.

Expectations of a well-supplied market in the near term, greater demand uncertainty, and lower oil and gas prices have reduced the number of FIDs and long-term foundational contracts that have been signed over the past two years. A number of projects were delayed or cancelled in 2016 and 2017 owing to project economics and partner alignment challenges in the current market environment. Given the large number of projects aiming to reach an FID in 2018, further culling of projects is expected.

Project Economics

Many project sponsors are seeking to reduce costs to bolster their projects' competitiveness. The extent to which they are successful will likely have a significant impact on which projects are sanctioned in the near term. Fiscal and regulatory certainty, which has been a challenge in some emerging liquefaction regions, can also impact project costs.

LNG Canada, for example, has rebid EPC work on a competitive basis. The government of British Columbia, where LNG Canada and all other Western Canadian proposals are located, also announced a series of fiscal measures in March 2018 intended to improve projects' competitiveness. Other projects, such as the now state-owned Alaska LNG project in the US, seek to benefit from tax-exempt status and lower financing costs. To expedite marketing and financing, some sponsors have incorporated options for a phased approach or reduced scope into their development plans.

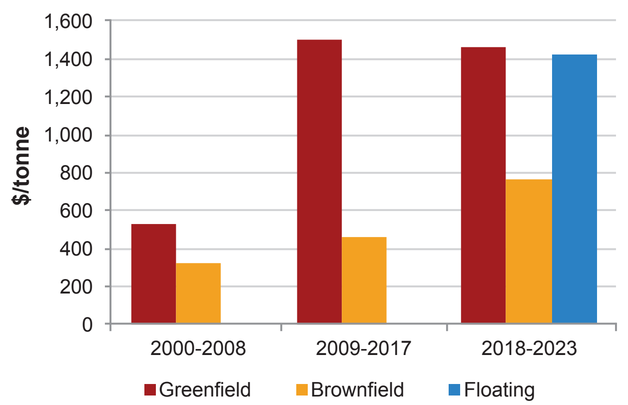
Politics, Geopolitics, and Environmental Regulation

There are a variety of political, geopolitical, and regulatory uncertainties across liquefaction regions that have the potential to impede the pace of project development.

Projects in operation, including Yemen LNG and Nigeria LNG, have been impacted by security issues. Yemen LNG declared force majeure in 2015 and remains offline owing to an ongoing civil war. Nigeria LNG has declared force majeure on numerous occasions due to regional violence and attacks on infrastructure, though output improved in 2017.

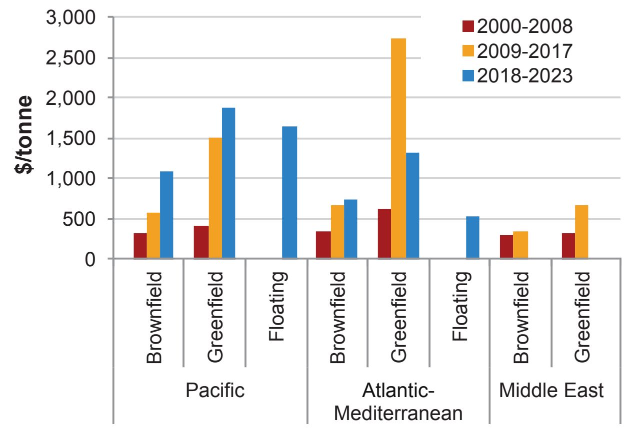
[7] According to the Oxford Institute for Energy Studies paper, "LNG Plant Cost Escalation", equipment costs include the cryogenic heat exchangers, compressors and drivers, power plant, and storage tanks. Bulk materials are assumed to refer to steel and other raw materials. Owner's costs include all technical and commercial components of project management prior to the commencement of operations, including costs associated with contractors/consultants for pre-FEED and FEED, environmental impact studies, and contract preparation prior to FID, as well as working with financiers and government and regulatory authorities.

Figure 4.10: Average Liquefaction Unit Costs in $/tonne (real 2016) by Project Type, 2000–2023



Sources: IHS Markit, Company Announcements

Figure 4.11: Average Liquefaction Unit Costs in $/tonne (real 2016) by Basin and Project Type, 2000–2023



Sources: IHS Markit, Company Announcements

Sanctions remain a challenge to LNG project development in Russia and Iran. US and EU sanctions against Russia's energy, defense, and financial sectors have broadened since being imposed in 2014, providing greater uncertainty around future project development in the country, though Yamal LNG was ultimately able to secure financing and has begun exports.

Regarding Iran, there is concern that the sanctions lifted in 2016 could be reimposed should the US decide to do so. This uncertainty could complicate TOTAL's plans to develop Phase 11 of the South Pars field. Even if the agreement remains in force, Iran's LNG ambitions face numerous challenges as US companies still cannot invest in the country. Iran is unable to use US-sourced liquefaction technology, and many secondary sanctions against non-US financial institutions remain in place. Restrictions on US dollar transactions may complicate financing efforts.

Extensive regulatory requirements, particularly in developed supplier countries, can be time-consuming and costly. In many cases the process, while rigorous, is nonetheless predictable. In some circumstances, however, such as with the now-cancelled Pacific Northwest LNG project in Canada, the review process can be protracted due to local opposition. Other countries, such as Mauritania, Senegal, and Tanzania are still developing their gas and LNG regulatory frameworks, which will in part drive the pace of project development.

Partner Priorities, Ability to Execute, and Business Cycles

Partner alignment is critical to reaching an FID, while divergent priorities and views on market fundamentals can result in project delays or cancellations. For companies with multiple projects, investment decisions will be made within the context of their broader portfolios. The size of the investment may also impact project participants' decisions to proceed.

Market and macroeconomic conditions have been important factors in the reduction in foundational contracting activity and FIDs over the past two years. Several projects have referenced weaker market conditions when announcing they would no longer proceed.

For their part, buyers have been more reluctant to commit to long-term contracts owing to uncertainty around their demand requirements as well as oil and gas prices. For instance, the trajectory of nuclear power plant restarts in Japan could significantly impact the country's LNG requirements, and some emerging markets have proposed ambitious LNG import or gas-fired power generation targets that may not be fully achieved. Some buyers wish to procure more LNG on a spot or shorter-term basis as a means of dealing with this unpredictability or otherwise diversifying their portfolios; others may be seeking lower prices before committing to a long-term contract during what may be a period of oversupply.

Potential customers and financiers must also be confident in the technical, operational, financial, and logistical capabilities of project sponsors and their partners to ensure that a project reaches FID and performs as expected. This has become increasingly important as a number of proposed projects, most notably in North America, are being developed by companies with limited or no direct liquefaction experience.

Feedstock Availability, Domestic Gas Needs, and Fuel Competition

Gas supply challenges and/or growing domestic demand have impacted production at projects in Algeria, Australia, Egypt, Indonesia, Oman, and Trinidad. For some projects, they also pose a challenge for future production as fields mature.

CBM-based projects in Eastern Australia faced significant pressure in 2017 to supply more gas locally in response to high domestic gas prices. Certain drilling restrictions and capital spending reductions have hindered domestic production growth, while significant volumes have been contracted for export as LNG. The Australian government in 2017 enacted a temporary mechanism to ensure that domestic demand was fulfilled, with the possibility of export controls being imposed in the event of a shortfall. To avoid such restrictions, the East Coast LNG producers and the Australian government reached an agreement in October 2017 to ensure sufficient domestic gas supply in 2018 and 2019.

Progress on new upstream developments has accelerated over the past two years, which if developed could extend the life of some existing liquefaction plants by either supplying them directly or being used to fulfill domestic demand. For example, the Browse and Scarborough fields are being proposed to backfill North West Shelf and Pluto LNG in Australia. Exports from Oman LNG may be extended as a result of new production from the Khazzan field that began in 2017. While Egypt intends to direct most new production to the domestic market in order to return to gas self-sufficiency, the successful commercialisation of Cypriot or Israeli gas via Egypt could support a return to exports on a larger scale.

In end-markets, the competitiveness of LNG versus pipeline gas (if applicable) and alternate fuels remains an important factor in liquefaction investment decisions.

Marketing and Contracting

The long-term contracting environment remained challenged in 2017. With expectations that the significant LNG supply buildup in the near term may potentially result in lower prices, most buyers have been reluctant to sign long-term foundational contracts to underpin new liquefaction capacity. Some, such as those with uncertain demand requirements, have instead increased reliance on spot, short, or medium-term contracts. However, there is recognition that new liquefaction capacity, and therefore long-term contracts, will be needed to prevent a significant market tightening in the next decade. Indeed, several long-term contracts associated with new trains have been signed so far in 2018.

There is significant competition for customers. New liquefaction proposals are competing with existing projects seeking to maintain production via potentially lower-cost backfill opportunities or additional trains. In this environment, there has been downward pressure on contract pricing terms, including slopes for oil-indexed contracts and capacity fees at some US projects, in addition to shorter lengths and proposals for alternative commercial structures. Several buyers have been able to renegotiate existing long-term contracts at lower prices, though they have typically come with larger volume requirements or longer terms.

Some emerging LNG buyers continue to secure volumes via fixed-destination agreements, while other LNG customers, including traditional buyers in Asia, are seeking greater destination flexibility to manage their portfolios. Japanese buyers are unlikely to sign new contracts with destination clauses as recommended by a Japan Fair Trade Commission report issued in 2017.

Companies that have traditionally served as foundational buyers, such as aggregators or certain utilities, have portfolios that may require or benefit from full destination flexibility. Commodity traders are also increasing their presence in the LNG market and in 2017 signed long-term foundational offtake contracts for the first time. These types of companies are important intermediaries between project sponsors and higher risk markets that may not have sufficient credit ratings to support a liquefaction project FID.

While most LNG projects will likely require long-term contracts to move forward, certain types of projects may not, depending on project scope (e.g., new train versus existing train), project costs, financing plans, risk tolerance, and return expectations.

4.8. Update on New Liquefaction Plays

Several regions around the world have proposed large amounts of new liquefaction capacity based on significant gas resources. Progress was achieved on both the commercial and regulatory

Table 4.1: Liquefaction Project Development Risks

Risk Factors	Impact on LNG Project Development
Project Economics	Long-term sales contracts that allow for a sufficient return typically underpin the financing of LNG projects. High project costs or changing market prices can have a large impact on when or if a project is sanctioned, and cost overruns post-FID can impact project returns.
Politics & Geopolitics	Permitting may be time consuming. National or local governments may not be supportive of exports and could levy additional taxes on LNG projects or establish stringent local content requirements. Political instability or sanctions could inhibit project development or operations.
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 an FID may be difficult.
Ability to Execute	Partners must have the technical, operational, financial, and logistical capabilities to fully execute a project. Certain complex projects may present additional technical hurdles that could impact project feasibility.
Business Cycle	Larger economic trends (e.g., declining oil prices, economic 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 pipeline gas or 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. In some cases, it may also limit the life of existing projects.
Marketing/Contracting	Project developers generally need to secure long-term LNG buyers for a large portion of project capacity before sanctioning a project. Evolving or uncertain market dynamics may make this task more difficult.

Wheatstone – Courtesy of Chevron

fronts in 2017 and early 2018 despite an investment hiatus. Projects are examining ways to improve their competitiveness, though political and geopolitical risks remain in some regions, which can extend development timelines.

United States

As of March 2018, four trains totalling 18 MTPA were operational in the US, all at Sabine Pass LNG. The first two trains started up in 2016, while the latter two began commercial operations in 2017. Six projects totalling 48.6 MTPA remained in the construction phase. Cove Point LNG will be the next facility to start up; the facility exported its first cargo in March 2018, with commercial service expected to start by April. Exports from Elba Island LNG are announced to begin in mid-2018. Larger capacity additions are likely in 2019, due in part to construction delays that have pushed back some projects previously expected online this year.

With all sanctioned US liquefaction capacity expected to be online by 2020, developers are focusing on the next wave of US LNG supply; there was 336 MTPA of proposed US capacity as of March 2018, and many projects intend to come online in the early to mid-2020s when some companies foresee a tighter market.

Challenging LNG market conditions and competition amongst US LNG projects and global counterparts have made it more difficult to sign binding offtake agreements, and numerous projects have pushed back their anticipated start dates. Additionally, current US LNG customers are seeking to place some of their contracted volumes via recontracting as well as time or destination swaps to reduce shipping costs.

Only one US project – Calcasieu Pass LNG – signed a binding long-term contract in 2017, with Italy's Edison. Shell, the project's first customer, signed an SPA for 1 MTPA in 2016 and agreed in February 2018 to purchase an additional 1 MTPA. Two binding contracts between Cheniere and China's CNPC were also signed in early 2018. In conjunction with a contract signed with Trafigura in early 2018, the deals are expected to support an FID at Corpus Christi LNG T3. The CNPC agreements stem from a memorandum of understanding (MOU) signed last November and are the first long-term deals signed between a US LNG developer and Chinese companies.

With the exception of Cheniere's Sabine Pass and Corpus Christi projects, the current slate of sanctioned US project developers act as infrastructure providers under a tolling model. A number of sponsors of new US projects are taking on additional roles across the LNG value chain. More proposed projects plan to manage feedstock procurement for potential customers under an LNG sales and purchase agreement (SPA) contracting model. In an attempt to reduce feed gas costs, some companies have acquired or are proposing to acquire upstream assets or otherwise secure favorable basis differentials. Some projects are also willing to offer delivered ex-ship (DES) sales, which would require them to charter a shipping fleet, to tap more markets. In some cases, this also involves additional downstream investment, such as in regasification terminals and gas-fired power plants.

A wide variety of contracting structures and business models is also being proposed. There is greater willingness to offer more types of indexation and various contract lengths. In addition, Driftwood LNG developer Tellurian has proposed an equity LNG business model under which customers would invest up front and receive LNG at cost.

Outside the continental US, the approximately 20 MTPA Alaska LNG made progress in 2017 after the State of Alaska, via Alaska Gasline Development Corporation (AGDC), assumed control of the project in late 2016. In November 2017, AGDC and the State of Alaska signed a non-binding Joint Development Agreement with Sinopec, CIC Capital, and the Bank of China, which allocates 75% of the capacity to China in exchange for it financing 75% of the plant cost. AGDC will market the remaining capacity and has signed several non-binding MOUs with counterparties in Asia.

The US regulatory process remains time-consuming and expensive, but it is unlikely to be a major obstacle for most projects.[8] Twelve projects[9] have received environmental approval from the Federal Energy Regulatory Commission (FERC). Jordan Cove LNG was the first LNG export project denied FERC approval, but the project restarted the process in 2017.

Canada

The Western Canada Sedimentary Basin (WCSB) is one of the most prolific gas basins in the world with over 1,000 Tcf of reserves estimated. It is advantaged relative to the US Gulf of Mexico by low-cost AECO supply and much shorter shipping distances to Asian markets. However, the greenfield nature and location of the developments, which require the need for lengthy pipeline infrastructure to transport gas from the WCSB to the British Columbia coast, have contributed to higher cost estimates for Canadian projects relative to proposals on the US Gulf of Mexico coast. As a result, some projects in Canada have been unable to secure customers. Reduced capital budgets, the availability of potentially more cost-effective sources of supply, and uncertain demand in some partners' home markets have slowed project momentum since 2015.

LNG development in Canada remained challenged in 2017 and early 2018. Over the past two years, a series of projects has been cancelled or re-paced. The most notable cancellation in 2017 was the 12 MTPA Pacific Northwest LNG project, one of the country's highest-profile proposals at the time of cancellation. Other proposed projects including Aurora LNG, Douglas Channel FLNG, Grassy Point LNG, Malahat FLNG, Prince Rupert LNG, Tilbury LNG, and Triton FLNG were also cancelled or delayed in 2016 and 2017.

Sponsors of remaining projects are seeking ways to increase their competitiveness. LNG Canada, which postponed an FID in 2016, shortlisted two bidders for a lump-sum EPC contract in February 2018. LNG Canada has publicly shared plans to award the contract and decide whether to proceed with an FID later in 2018. The Kitimat LNG project has focused on cost reductions in plant design along with advocating for a clear, stable, and competitive fiscal framework with the government. The smaller Woodfibre LNG project completed a parallel FEED process in 2017 and also expects to finalise an EPC contract in 2018.

Taxes and tariffs could impact the competitiveness of Canadian LNG. In 2017, the Canada Border Services Agency announced anti-dumping duties on certain fabricated industrial steel components, which could be applied to portions of LNG projects. Moreover, while the British Columbia government provided clarity on taxation in 2014 and 2015 via a new LNG export-specific tax and royalty regime, project sponsors continue to advocate for more competitive government arrangements at the provincial and federal levels. In March 2018, the British Columbia government introduced a new gas development framework, which included a series of fiscal measures, intended to improve the competitiveness of LNG projects in the province.

The environmental review process in Canada has generally taken approximately two years to complete, though in some cases, such as the now-cancelled Pacific Northwest LNG, the process was significantly longer.[10] Impacted First Nations, including those with traditional territories along associated pipeline routes, must also be accommodated and provide consent. First Nations and other local opposition emerged as a significant hurdle for Pacific Northwest LNG. Project proponents have made efforts to work collaboratively with affected First Nations. For example, Kitimat LNG has several First Nations partnerships that are unique in the Canadian energy industry, including benefit agreements with the Haisla Nation for the LNG plant and an agreement with all 16 First Nations along the proposed Pacific Trail Pipeline route through the First Nations Limited Partnership (FNLP). Woodfibre LNG and FortisBC participated in a parallel First Nations environmental process and agreed to legally binding commitments. Additionally, the Kwispaa at-shore FLNG project is being co-developed with First Nations.

Several projects totalling 47.5 MTPA have been proposed in Eastern Canada. They plan to source feed gas from the US and offshore Canada in the Atlantic. As liquefaction development has slowed in Western Canada, some sponsors have also discussed sourcing feed gas from the WCSB. Most projects in Eastern Canada depend on pipeline reversal and capacity expansions and appear to be targeting the Atlantic Basin for their marketing efforts. Goldboro LNG has an SPA with Uniper and a loan guarantee from the German government.

East Africa

East Africa's LNG supply ambitions gained momentum in 2017, when Coral South FLNG in Mozambique became the first project in the region to reach an FID. Owned by Eni, ExxonMobil, KOGAS, CNPC, Galp Energia, and Mozambique's national oil company Empresa Nacional de Hidrocarbonetos (ENH), the project has contracted its entire 3.4 MTPA capacity to BP and is expected online in 2022.

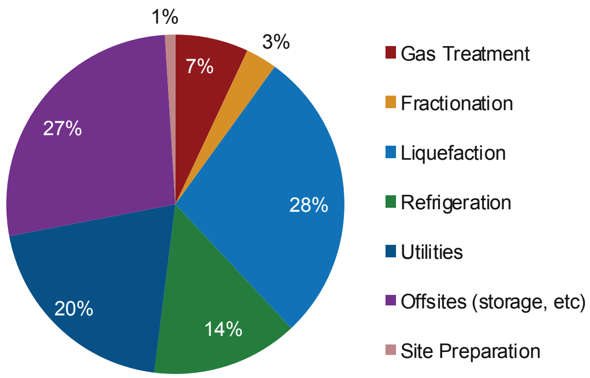
Apart from Coral South FLNG, several other floating and onshore projects totalling 70 MTPA have been proposed following large offshore dry discoveries in Mozambique and Tanzania. The development plan for a 12 MTPA onshore proposal by the Mozambique Area 1 partners – Anadarko, Mitsui, ONGC Videsh, Oil India, Bharat Petroleum, PTT, and ENH – received government approval in March 2018. The foundational legal and contractual framework has also been approved, and the site preparation and resettlement processes commenced in Q4 2017. LNG is being marketed jointly by

[8] Two major sets of regulatory approvals are needed to move forward: environmental/construction approval, primarily from the Federal Energy Regulatory Commission (FERC) or United States Maritime Administration (MARAD) in the case of offshore FLNG facilities outside of state waters, and export approval from the Department of Energy (DOE). DOE approval has two phases. Approval to export to countries with which the US holds a free trade agreement (FTA) is issued essentially automatically. For non-FTA approved countries, a permit will be issued only after the project receives full FERC approval.

[9] Sabine Pass LNG T5-6 and Cameron T4-5 are counted separately from their initial phases. The onshore portion of Delfin FLNG is also included.

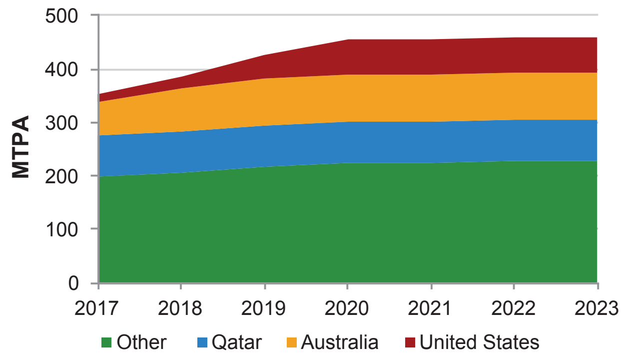
[10] The Canadian Environmental Assessment Agency (CEAA) is the lead agency for environmental reviews, though in some cases a provincial environmental assessment can substitute for a federal environmental assessment. In 2016, the federal government announced its intention to incorporate direct and upstream greenhouse gas emissions into the environmental review process. Projects must also receive export approval from the National Energy Board (NEB). Several projects have received 40-year export licences following legislation that extended the maximum licence term from 25 to 40 years. For projects planning to use US gas, approval from the US DOE and an import license from the NEB are also required.

Figure 4.12: Average Cost Breakdown of Liquefaction Project by Expense Category



Source: Oxford Institute for Energy Studies

Figure 4.13: Post-FID Liquefaction Capacity Build-Out, 2017–2023



Note: This build-out only includes existing and under-construction projects.
Sources: IHS Markit, Company Announcements

the Area 1 partners, and operator Anadarko has stated that 8.5 MTPA of contracted offtake is necessary for an FID. As of March 2018, the partners had contracted or agreed to key terms for 5.1 MTPA. Mozambique's ongoing debt crisis is a potential obstacle. However, an agreement was reached to fund the equity share of ENH. Repayments will be made with profits from future LNG sales.

In December 2017, ExxonMobil finalised the acquisition of a 25% stake in Area 4; the company will operate future onshore liquefaction projects utilising standalone Area 4 gas resources. Discussions regarding potential coordination or infrastructure sharing between the Area 1 and 4 partners are ongoing. The Area 1 and 4 partners had agreed on unitisation terms in 2015. Under the agreement, they will each develop 12 Tcf separately but in coordination, following which additional resources will be developed under a 50:50 joint venture.

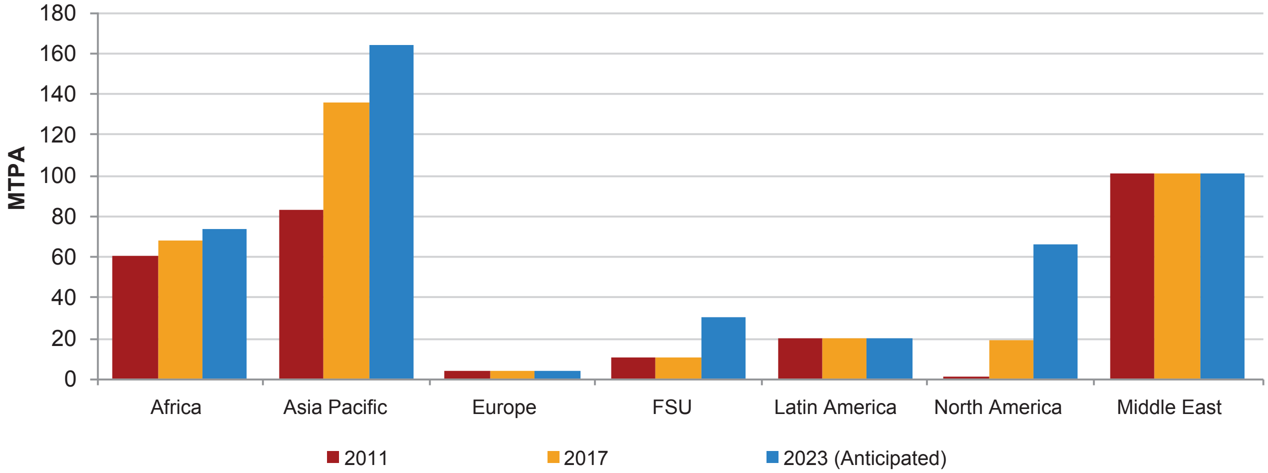
LNG development in Tanzania is at a more preliminary stage. Significant regulatory challenges remain. Oil and gas policy and regulatory reforms began in 2015, but they must be implemented prior to an FID. A new gas policy has also been approved, but a formal law regarding the country's Gas Master Plan must still be passed. Furthermore, legislation passed in 2017 indicates an increasingly nationalistic approach to development of the mining and hydrocarbon sectors, which may complicate LNG project development.

West Africa
Following Kribi FLNG in Cameroon, which is expected to commence exports in April 2018, development continues to progress at several, primarily floating, liquefaction proposals in West Africa.

Fortuna FLNG in Equatorial Guinea is planning to reach an FID in 2018 once financing is completed. The project has faced delays in securing financing from Chinese banks and is now pursuing alternative options, which have moved to an advanced stage. In August 2017, Gunvor was selected as the offtaker and will purchase 2.2 MTPA for ten years. The agreement enables the project partners to market up to 1.1 MTPA under certain conditions.

Prelude FLNG – Courtesy of Shell

Figure 4.14: Liquefaction Capacity by Region in 2011, 2017, and 2023



Note: Liquefaction capacity only includes existing and under-construction projects. Sources: IHS Markit, Company Announcements

Several liquefaction projects have been proposed to commercialise approximately 40 Tcf of gas resources in Mauritania and Senegal. Development of the first project, Greater Tortue FLNG, continues at an accelerated pace. In 2016, BP made a large equity investment and now has a majority stake in the upstream and liquefaction assets. Both governments have demonstrated their alignment and commitment to the project, as evidenced by the signing of a unitisation agreement in February 2018. Following the announcement, an FID is expected by the end of 2018 with first gas commencing in 2021. Additional resources could be monetised via FLNG or an onshore scheme. Several resources located only in Senegal are also potential targets for LNG development.

In Nigeria, a two-train expansion at the existing Nigeria LNG complex is under consideration. The development concept was revised in 2016 from a single 8.4 MTPA train to two smaller trains with capacities of 3.2 and 4 MTPA. The 10 MTPA Brass LNG project continues to undergo a planning review by partners Nigerian National Petroleum Corporation (NNPC), TOTAL, and Eni. The Petroleum Industry Governance Bill (PIGB), which would restructure the oil and gas sector including NNPC, is expected to be made law shortly. It is likely that the other components of the Petroleum Industry Bill (PIB), which address additional elements of the hydrocarbon legal and fiscal framework, would also need to be passed before additional investments are made.

Russia

The 16.5 MTPA Yamal LNG project in the Russian Arctic exported its first cargoes on schedule in 2017. The second and third trains remain under construction and are expected online in 2018 and 2019, respectively. Yamal LNG was able to resolve financing challenges stemming from US and EU sanctions on Russia in 2016, but sanctions against the Yuzhno-Kirinskoye field has challenged development of a third train at Sakhalin-2 LNG. The field is a key feedstock source for the train, and limited progress has been made on alternative gas supply options.

The impact of existing or possible future sanctions on other proposed projects is unclear. Russia plans to develop an indigenous LNG industry in tandem with its large-scale development plans. Arctic LNG-2 intends to utilise a greater proportion of equipment and technology manufactured in Russia, a primary goal of which is to lower costs. If successful, it may also reduce the impact of potential future sanctions. Novatek's proprietary Arctic Cascade process could be deployed in a small 0.9 MTPA expansion at Yamal LNG, to be financed by the project shareholders.

Table 4.2: Nominal Liquefaction Capacity by Region in 2011, 2017, and 2023

Region	2011	2017	2023 (Anticipated)	% Growth 2011–2017 (Actual)	% Growth 2017–2023 (Anticipated)
Africa	60.3	68.3	74.1	13%	8%
Asia Pacific	82.8	135.9	164.3	64%	21%
Europe	4.2	4.2	4.2	0%	0%
Former Soviet Union	10.8	10.8	30.0	0%	177%
Latin America	20.0	20.0	20.0	0%	0%
North America	1.5	19.5	66.6	1200%	241%
Middle East	100.8	100.8	100.8	0%	0%
Total Capacity	**280.3**	**359.5**	**459.9**	**28%**	**28%**

Note: Liquefaction capacity only includes existing and under-construction projects. Sources: IHS Markit, Company Announcements

Australia and Papua New Guinea
Australia's current liquefaction capacity buildout is expected to finish later in 2018 as Prelude FLNG, Ichthys LNG, and Wheatstone LNG come online. Expansion trains have been proposed on both coasts. Amidst an increasingly competitive market and the need to ensure sufficient gas supply is available to the East Coast domestic market, the focus has shifted to backfilling existing trains or smaller capacity expansions on the West Coast.

The Barossa field is the primary choice to supply Darwin LNG as the Bayu-Undan field begins to mature in the early 2020s. Woodside plans to monetise the Scarborough development through a 0.7-3.3 MTPA expansion of the existing 4.9 MTPA Pluto LNG facility. In February 2018, Woodside announced it would increase its stake in Scarborough, providing greater partner alignment across the project. An FID is expected in 2020, with production starting in 2025. The Browse development is proposed to backfill North West Shelf LNG, with an FID slated for 2021. To enable synergies, an interconnector between Pluto and North West Shelf LNG is under study. While utilising existing infrastructure will lower costs, both concepts would require the construction of lengthy pipelines.

Separately, Timor-Leste and Australia signed a permanent maritime boundary agreement in March 2018, resolving a boundary dispute that had been an impediment for development of the cross-border Greater Sunrise fields. The agreement, however, did not specify a definitive gas commercialisation plan, indicating development of the field is likely a longer-term opportunity.

An expansion in Papua New Guinea gained momentum in 2017 and early 2018 following additional progress on partner alignment. In 2017, ExxonMobil – operator of the existing PNG LNG project finalised the acquisition of InterOil, which had a stake in the greenfield Papua LNG project led by TOTAL. In February 2018, a broad agreement was reached between partners in both projects to pursue three trains totalling 8 MTPA. Two trains will be allocated to Papua LNG, and one train will be allocated to PNG LNG. A decision on FEED is expected in the second half of 2018.

Eastern Mediterranean
With new production from the Zohr, Atoll, and West Nile Delta fields in Egypt largely expected to serve the domestic market, the emergence of the East Mediterranean region as a large-scale LNG supplier is likely to depend on successful monetisation of the Leviathan and Aphrodite developments as well as any major future discoveries.

The first phase of the Leviathan development in Israel reached an FID in February 2017. Sales from this phase will be directed to the Israeli and Jordanian markets. Should a dispute over the 2012 halt of Egyptian exports to Israel be resolved, substantial volumes will also reach private Egyptian customers. Additionally, contract talks aiming to monetise gas from Cyprus and Israel via Egyptian liquefaction plants are reportedly making progress. These proposals face numerous political and commercial challenges, especially given their cross-border nature.

Looking Ahead

Will liquefaction investment activity remain muted in 2018? Only 9.7 MTPA of liquefaction capacity has been sanctioned since the beginning of 2016. Many projects are seeking to reach an FID in 2018 and 2019 to come online in the 2020s when some market participants expect material new LNG supply will be needed. However, most proposals remain uncontracted and are competing for buyers willing to commit to long-term contracts in a relatively low-priced environment. Additionally, the potential for relatively lower-cost expansions and backfill opportunities, in addition to expiring contracts at legacy projects, may reduce the amount of capacity required from new projects in the near term. With downward pressure on costs and contract pricing and higher oil prices, it is possible that FIDs could rebound this year, particularly if suppliers show a willingness to invest without contracts. Several long-term contracts associated with new trains have been signed so far in 2018.

Is a significant LNG surplus still expected? Many, but not all, market participants continue to expect a near-term LNG surplus to emerge over the next several years, with the market rebalancing in the early to mid-2020s. The timing and scale of a potential surplus is subject to numerous supply and demand sensitivities. Construction delays and slow ramp-ups at some projects reduced supply in 2016 and 2017. The extent to which new projects coming online adhere to their announced schedules will be a key factor to a potential oversupply, along with the extent of any potential upside or downside demand shifts. The amount of capacity sanctioned over the next several years will in part determine the timing of an expected market rebalancing in the 2020s.

Will floating LNG be adopted on a wider scale in the coming years? In 2017, PFLNG Satu in Malaysia became the first FLNG project to begin exports and had shipped an estimated four cargoes as of March 2018. Three FLNG projects, including the first based on a vessel conversion, are expected to come online this year. The market will be watching how they ramp up to assess the initial performance of the various development concepts and the overall longer-term potential of FLNG. Kribi FLNG in Cameroon has begun LNG production and plans to start exports in April 2018. Several FLNG projects are planned to utilize a similar conversion design, and so its performance could be a particularly important factor in the amount of future capacity based on smaller-scale FLNG conversions. Greater visibility into the cost competitiveness of FLNG, including the potential impact of construction delays, is likely as more capacity comes online.

KC LNG Tech. KC-1 - Courtesy of Kogas

5. LNG Carriers

Over the past decade, the LNG shipping sector has been affected by significant changes in the broader LNG market. The cyclical nature of the sector has seen charter rates fall from historic highs in 2012, after the Fukushima disaster in Japan caused a spike in the need for spot deliveries, to historic lows experienced in the summer of 2017. The buildup in new shipping tonnage experienced since 2013 has had lingering dampening effects on charter rates, even while new deliveries more evenly matched additions in LNG supply in 2017. For the first nine months of the year, average rates remained low at around $23,500/day for conventional steam carriers and $37,000/day for dual-fuel diesel electric/tri-fuel diesel electric (DFDE/TFDE) carriers.

Notably, toward the end of 2017, there was a significant uptick in charter rates owing to peaking Asian demand, particularly in China; by December, average rates for conventional steam carriers reached $44,300/day, and those for DFDE/TFDE carriers reached $81,700/day. Charter rates may fall again in 2018 as the market enters the shoulder and summer months. The upcoming delivery of newbuilds should keep the LNG shipping market well-supplied, with a seasonal uptick in rates during winter months. However, expected deliveries begin to thin considerably after the next two or three years, and if more orders aren't placed to match significant additions in liquefaction capacity expected through 2021, the LNG shipping market could re-enter a period of tightness in the medium term.

5.1. Overview

By the end of 2017, the LNG fleet totalled 478 vessels, including those vessels actively trading, sitting idle available for work, and acting as floating storage and regasification units (FSRUs).[1] Of the total global LNG fleet, there are 27 FSRUs and three floating storage units. The overall global LNG fleet grew by 6.4% in 2017, as 27 carriers were added to the fleet (see Figure 5.1), including three FSRUs. The global LNG fleet growth was in line with the 22.3 MTPA in new liquefaction capacity that came online during the year. However, charter rates remained depressed for much of the year as the market was still working its way through the excess tonnage of newbuild deliveries from the previous years.

The shipping market continued to add new tonnage in 2017, continuing a pattern of growth established in early 2013. Up until 2017, this buildout of new tonnage consistently outweighed the incremental growth in globally traded LNG, which was reflected in the strong decline in charter rates.

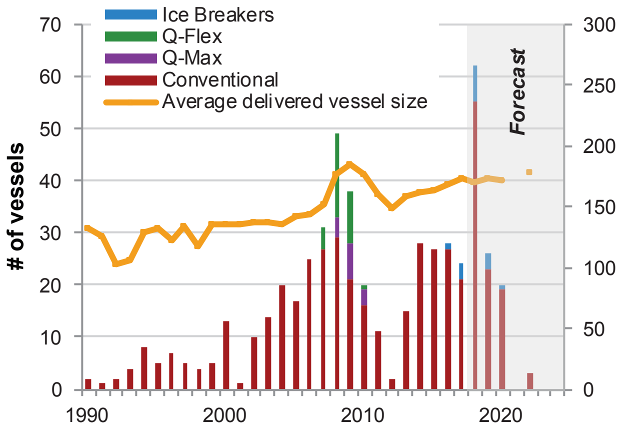
478 vessels
Number of LNG vessels (including chartered FSRUs) at end-2017

Carrier storage capacity has increased over the years, supported by a push to build ever-larger vessels in the early 2010s, reflected in the buildout of the Qatari Q-Max and Q-Flex fleet. However, the newbuild deliveries and newbuild orders seen during 2017 indicate that the market is settling on a carrier size of between 170,000 cubic metres (cm) and 180,000 cm, which coincides with the size limits for the new Panama Canal expansion. The average LNG storage capacity for a newbuild delivered during 2017 was a little above 173,000 cm.

Eduard Toll – Courtesy of Teekay

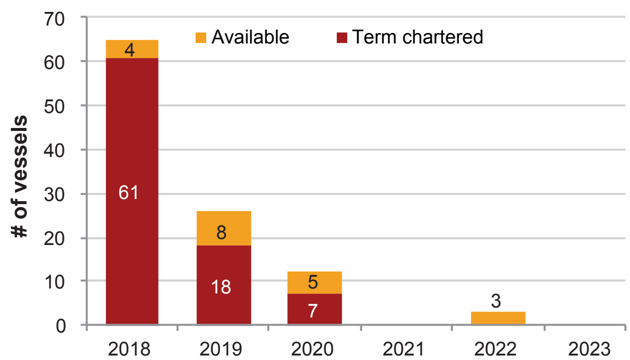
[1] For the purposes of this report, only LNG vessels with a capacity greater than 60,000 cm are considered part of the global fleet and included in this analysis. All vessels below 60,000 cm are considered small-scale.

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



Note: The graph above excludes FSRUs and floating storage units.
Source: IHS Markit

Figure 5.2: Estimated Future Conventional Vessel Deliveries, 2018–2023



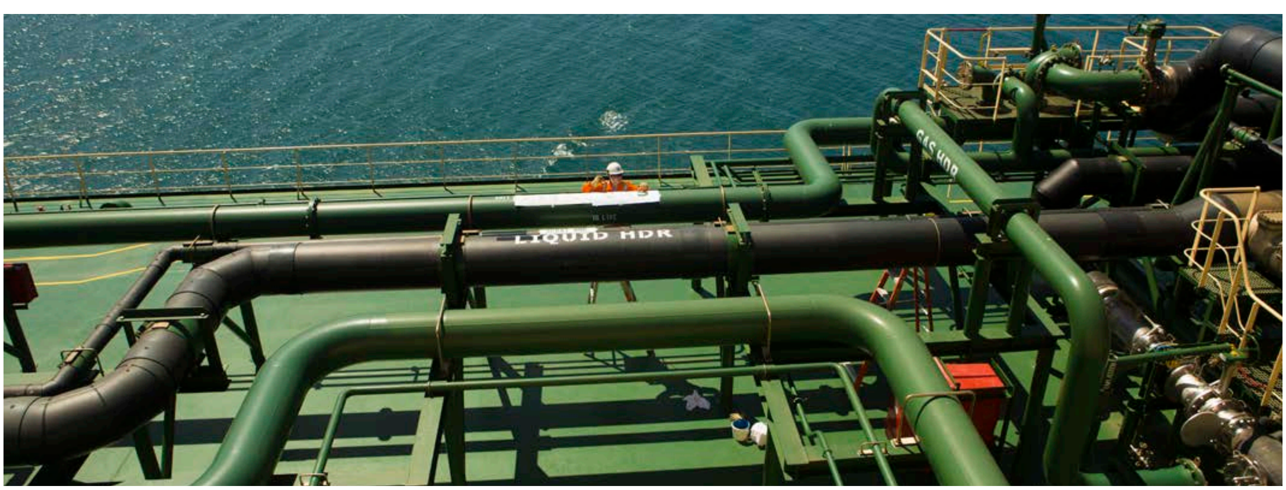
Note: Available = currently open for charter. Source: IHS Markit

The order book at the end of 2017 contained 106 carriers expected to be delivered through 2022, 18 of which were ordered during the year; a 157% increase from 2016. This increase in newbuild orders is a result of both LNG offtakers ordering ships for new liquefaction capacity and speculative orders by shipowners. There has been a slowdown in project final investment decisions (FIDs) being reached, which in the past would have hindered the growth of the LNG fleet. However, with the growing participation of short-term traders and the increasing unpopularity of destination clauses in LNG contracts, LNG trade is becoming more dynamic and will require more tonnage to service deliveries. At the end of 2017, around 81% of the orderbook was tied to a specific project or charterer, leaving 20 carriers available for the spot market or to be chartered out on term business (see Figure 5.2).

In 2018, a further 65 carriers (including 5 FSRUs) are expected to be delivered from the shipyards, while an additional 43.3 MTPA of new liquefaction capacity is expected to come online. In the short run, the shipping market is anticipated to return to being mismatched with the liquefaction buildout, delivering more tonnage than the market needs. However, looking out post-2018, the orderbook is expected to experience a significant decline in deliveries for each year between 2019 and 2022, while an additional 58.7 MTPA of new liquefaction capacity is expected online during the same period. When the retirement or conversion of older steam carriers is taken into consideration, the market could experience tightening after 2020 if new vessels are not ordered.

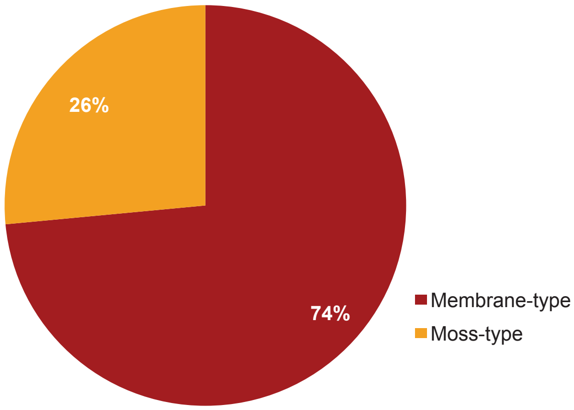
The Panama Canal played a significant role in 2017, with exports from Sabine Pass LNG in the US ramping up as the project brought an additional two trains online during the year, bringing total liquefaction capacity in the US Gulf of Mexico to 18 MTPA as of end-2017. Transit through the canal allows offtakers from the project to access Asian markets in only 22 days, as opposed to 35 days via the Suez Canal or Cape of Good Hope. There were 95 laden voyages transiting through the Panama Canal with Sabine Pass volumes. Compared to 2016, increased arbitrage between basins supported by higher prices in Asia led a higher percentage of voyages to go to Asia; of the 95 voyages, 65 sailed to Asian markets and 30 were delivered to Latin American markets. Initial constraints associated with the new Panama Canal expansion limited LNG transits to one per day, but the Panama Canal Authority is considering increasing LNG transits to two per day. Cheniere Energy became the largest LNG user of the canal with over 60 transits made in 2017.

Floating LNG became a reality in 2017, with the PFLNG Satu unit sending out its first cargo in April 2017. The unit is slowly



Courtesy of Chevron

Figure 5.3: Existing Fleet by Containment Type, end-2017



Source: IHS Markit

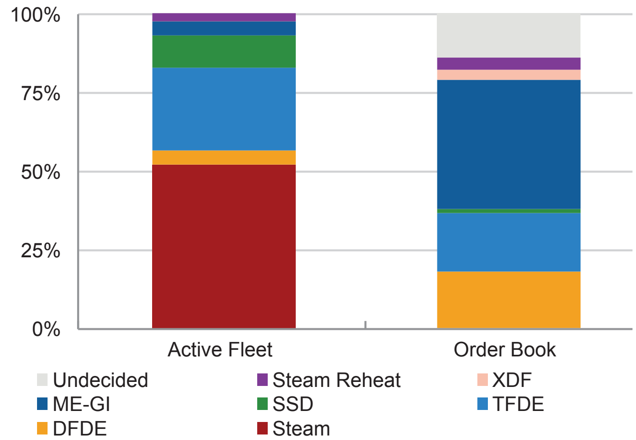
ramping up production, with four cargoes delivered throughout the year. The Prelude FLNG unit was delivered from the shipyard at the end of July 2017 and arrived at the Prelude field (475 km off the coast of Western Australia) in September 2017. The first cargo is expected in Q4 of 2018. The converted FLNG unit Hilli Episeyo was delivered in October 2017, and arrived on site in Cameroon for the Kribi FLNG project in November 2017; LNG production began in March with first exports expected in April.

5.2. Vessel Characteristics

Containment Systems. Two different designs were initially developed for LNG containment on vessels: the Moss Rosenberg design and the membrane-tank system using thin, flexible membranes supported only by the insulated hull structure. The Moss Rosenberg design started in 1971 and is well known by its independent spherical tanks that often have the top half exposed on LNG carriers. The most common membrane-tank systems have been designed by Gaztransport and Technigaz (GTT)[3] . Several GTT systems have been already implemented on board of LNG carriers for many years now and other designs from different companies have been recently developed. GTT recently developed new solutions to reduce boil-off rates to around 0.08%. Among these new systems, the Mark III Flex + and Mark V could possibly be implemented in the future on some newbuilds. A new version of the membrane containment design, KC-1, has been developed by KOGAS; it is installed on two vessels ordered by SK Shipping. At the end of 2017, 74% of the active fleet had a GTT Membrane-type containment system (see Figure 5.3), which also continues to lead the orderbook as the preferred containment option for 91% of vessels on order.

Both tank systems rely on expensive insulation to keep the LNG cold during the voyage and minimize evaporation. Nevertheless, an amount equivalent up to roughly 0.15% of the cargo evaporates per day. However, the rate of the boil off gas (BOG) is ultimately determined by the insulation of the LNG carrier, which in turn varies according to the containment system. Newer vessels are designed with lower BOG rates, with the best-in-class purporting rates as low as 0.08%.

Figure 5.4: Existing and On Order LNG Fleet by Propulsion Type, end-2016



Source: IHS Markit

Propulsion Systems. To keep the tank pressure close to atmospheric conditions per design conditions for Moss and membrane systems, BOG has to be taken out from the tanks, and has generally been used for fuelling the ships' steam-turbine propulsion systems which are reliable, but not optimal. Since the early 2000s, however, these systems specific to LNG carriers have undergone major innovations and enhancements, particularly to reduce fuel costs during an LNG voyage.

With a rise in bunker costs during the 2000s, the issue of fuel cost became ever more critical. Attempting to reconcile the objective of low fuel consumption with the necessity of consuming the BOG, innovative systems have taken a variety of approaches, depending on the specific transport concept, such as the carrying capacity, vessel speed, the duration of its potential voyages, and other voyage-specific factors. Any comparison of alternative concepts of LNG carrier propulsion and auxiliary energy generation must consider the overall complexity of LNG transport. Today, LNG carrier operators can choose between the following systems:

Steam Turbines. Steam turbines are the traditional propulsion system of LNG carriers. Usually two boilers generate sufficient steam for the main propulsion turbines and auxiliary engines. The boilers can also be partially or fully fuelled with heavy fuel oil (HFO). One important advantage of the steam turbine system is the fact that no gas combustion unit is necessary; all BOG is used in the boilers. Maintenance and other operating costs are considerably lower with steam propulsion systems when compared to other systems due to the simple design with BOG from the LNG.

On the other hand, low thermal efficiency and the resulting higher cargo transport costs are clear disadvantages. Large LNG carriers require more power than existing steam turbine designs can deliver. Moreover, manning the vessels with engineers that are qualified to operate steam-turbine systems is getting more difficult as this technology loses market share and fewer seamen pursue this qualification.

[3] GTT was formed in 1994 out of the merger between Gaztransport and Technigaz. Both companies had previous experience in designing and developing LNG carrier technologies.

Dual-Fuel Diesel Electric/Tri-Fuel Diesel Electric (DFDE/TFDE). After almost forty years of the LNG fleet consisting entirely of steam turbine propulsion systems, GDF SUEZ (now ENGIE) ordered the first LNG carriers to be powered by DFDE propulsion 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. DFDE propulsion systems are equipped with an electric propulsion system powered by dual-fuel, medium-speed diesel engines. In gas mode, these dual-fuel engines run on low-pressure natural gas with a small amount of diesel used as a liquid spark. The engine operators can switch to traditional marine diesel at any time.

These propulsion systems must be equipped to handle excess BOG. In contrast to steam propulsions, a Gas Combustion Unit (GCU) is necessary as it offers an appropriate means to burn the BOG when necessary. In addition, a GCU is needed to dispose of residual gas from the cargo tanks prior to inspection. The additional equipment needed for the BOG increases the amount of maintenance needed for the engines.

Shortly after the adoption of DFDE systems, TFDE vessels – those able to burn heavy fuel oil, diesel oil, and gas – offered a further improvement to operating flexibility with the ability to optimize efficiency at various speeds. While the existing fleet is still dominated by the legacy steam propulsion system, almost 26% of active vessels are equipped with TFDE propulsion systems. Additionally, the orderbook consists of 19% of vessels planned with TFDE systems (see Figure 5.4).

Slow-Speed Diesel (SSD) with a BOG Re-liquefaction Plant. Another propulsion system was introduced to the LNG shipping industry in the mid-2000s, primarily developed in tandem with the Qatari megatrain projects. Instead of using BOG to generate propulsion and/or electric energy, vessels are propelled by conventional low-speed diesel engines consuming HFO or marine diesel oil (MDO) generator sets.

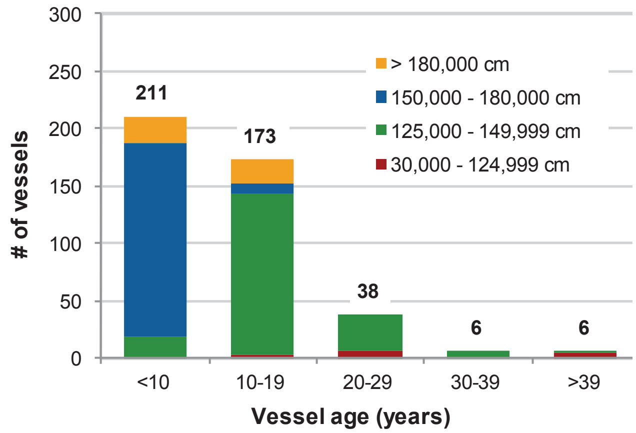
The BOG is instead entirely re-liquefied and fed back into the cargo tanks. An additional GCU allows BOG to be burned when necessary. This system permits LNG to be transported without any loss of cargo, which can be advantageous especially if HFO or MDO is comparatively cheaper than burning BOG for propulsion fuel.

Table 5.1: Propulsion Type and Associated Characteristics

Propulsion Type	LNG Fuel Consumption (tonnes/day)	Average Vessel Capacity	Typical Age
Steam	175	<150,000	>10
DFDE/TFDE	130	150,000-180,000	<15
ME-GI	110	150,000-180,000	<5
XDF	108	150,000-180,000	<1
Steam Re-heat	140	150,000-180,000	Not Active

Note: LNG fuel consumption figures in the table above are at designed service speeds. Source: IHS Markit

Figure 5.5: Active Global LNG Fleet by Capacity and Age, end-2017



Source: IHS Markit

During ballast voyages, the cargo tank temperature is maintained by spraying re-liquefied LNG back into the cargo tanks. This helps reduce the initial increase of BOG on laden voyages. The entirety of the Q-Class fleet is equipped with this propulsion type.

M-type, Electronically Controlled, Gas Injection (ME-GI). Around 42% of vessels in the orderbook are designated to adopt the newest innovation in LNG carrier engine design from MAN B&W: the ME-GI engine, which utilises high-pressure slow-speed gas-injection engines. Unlike the Q-Class that cannot accept BOG in the engine, ME-GI engines optimise the capability of slow speed engines by running directly off BOG – or fuel oil if necessary – instead of only re-liquefying the gas. 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. The ME-GI propulsion system now accounts for almost as many vessels in the order book as TFDE/DFDE carriers. This more fuel-efficient propulsion system seems to be gaining traction amongst ship owners as the bulk of the most recent newbuild orders have been placed for vessels with the ME-GI propulsion system. Currently there are 18 carriers in the global LNG fleet utilising this propulsion system, eight of which were delivered in 2017. The share of carriers utilising the ME-GI system is expected to more than double in 2018, as another 29 carriers utilizing it are expected to be delivered during the year.

Winterthur Gas & Diesel (WinGD) Low-Pressure Two-Stroke Engine. Wärtsilä introduced its low-speed, two-stroke, dual-fuel engine in 2014, and since 2015 the system has been marketed by WinGD (originally a JV between Wärtsilä and China State Shipbuilding Corporation (CSSC), though Wärtsilä has since transferred its stake to CSSC). This alternative to DFDE propulsion systems is estimated to offer capital expenditure reductions of 15–20% via a simpler and lower cost LNG and gas handling system. Significant gains are reportedly achieved by eliminating the high pressure gas compression system. In addition, the nitrogen oxides (NOX) abatement systems may not be required.

2016–2017 LNG Trade in Review

Global LNG Fleet **+24** Conventional carriers added to the global fleet in 2017	Propulsion systems **31%** Active vessels with DFDE/TFDE propulsion systems	Charter Market Steam $26,700 TFDE /DFDE $44,500 Spot charter rate per day in 2016	Orderbook Growth **+14** Conventional carriers ordered in 2017
The active fleet expanded to 434 conventional carriers in 2017 The average ship capacity of newbuilds in 2017 was 173,300 cm, a slight increase compared to 2016 Three FSRUs were also completed in 2017, two of which were already tied to import projects	In 2015, over 72% of the fleet was steam-based; by 2017, this had fallen to 63% The orderbook has a variety of vessels with new propulsion systems, including ME-GI and XDF, which together account for 44% of the vessels on order	Since 2014, 120 vessels have entered the market, outpacing incremental growth in LNG supply and pushing charter rates almost to operating costs Rates spiked at the end of 2017 owing to high Asian LNG demand, with TFDE/DFDE rates hitting an average $81,700/day in December	Only 6 vessels were ordered in 2016 as liquefaction project FIDs slowed, but additions to the orderbook more than doubled in 2017 Four FSRUs were also ordered in 2017 A third of the orders placed in 2017 were in the last month of the year, four of which were speculative

Others. In order to improve the performance of a traditional steam-turbine propulsion system, the Steam Reheat engine design was developed. The design is based on a reheat cycle, where the steam used in the turbine is reheated to improve its efficiency. This improvement in the steam adaptation maintained the benefits of the simple steam-turbine while improving overall engine efficiency.

Vessel Size. LNG vessels can vary significantly in size. While additions in the early 2010s demonstrated a bias toward vessels with ever larger capacities, recent deliveries have settled around a range of 170,000–180,000 cm, though this is still larger than historical averages. 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-2017, 46% of active LNG carriers had a capacity within this range, making it the most common vessel size in the existing fleet (see Figure 5.5), but this share is steadily decreasing. Conventional carrier newbuilds delivered during 2017 had an average size of 173,300 cm, and none of the 24 vessels had a capacity lower than 150,200 cm.

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. The Q-Class (45 vessels in total) accounted for 10% of the active fleet and 14% of total LNG transportation capacity at the end of 2017.

With the Panama Canal accommodating carriers of up to 180,000 cm under the vessel class known as the New Panamax[4], it will be difficult to justify a newbuild any larger than what is allowed through the Neopanamax locks. As a carrier's marketability is contingent on its flexibility to trade in different markets, not being able to pass through the Panama Canal would most likely exclude such a carrier from the US LNG trade. As of end-2017, 90% of the global LNG fleet meets new Panama Canal carrier size requirements, with the entirety of the orderbook also meeting the requirements.

Vessel Age. At the end of 2017, 45% of the active fleet was under 10 years of age, a reflection of the newbuild order boom that accompanied liquefaction capacity growth in the mid-2000s, and again in the early 2010s. Generally, shipowners

Fedor Litke – Courtesy of Dynagas

[4] The New Panamax is defined by length, breadth, and draught. The maximum capacity which still fits these dimensions has thus far come to about 180,000m^3, but there is no specific limitation on capacity.

primarily consider safety and operating economics when considering whether to retire a vessel after it reaches the age of 35, although some vessels have operated for approximately 40 years. Around 3% of active LNG carriers were over 30 years of age in 2017; these carriers will continue to be pushed out of the market as the younger, larger, and more efficient vessels continue to be added to the existing fleet.

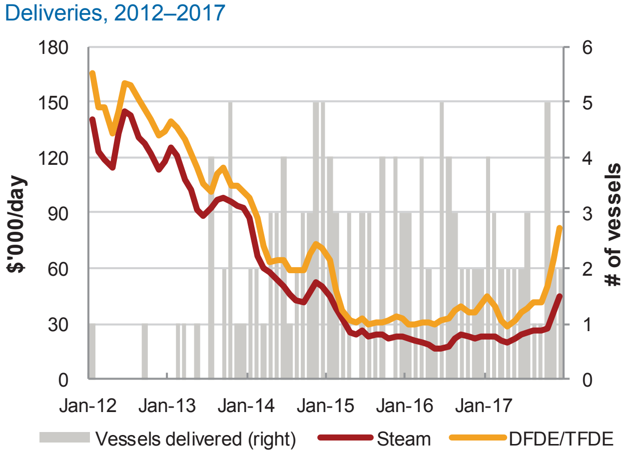
Typically, as a shipowner considers options for older vessels – either conversion or scrappage – the LNG carrier is laid-up. However, the vessel can re-enter the market. At the end of 2017, 19 vessels (primarily Moss-type steam carriers, all with a capacity of under 150,000 cm) were laid-up. Over 88% of these vessels were over 30 years old, and all were older than 10. While several carriers re-entered the market in 2017, a nearly equal number of carriers were laid-up, keeping the number relatively constant compared to the previous year.

As the newbuilds are delivered from the shipyards, shipowners can consider conversion opportunities to lengthen the operational ability of a vessel if it is no longer able to compete in the charter market. In 2016, two vessels were retired from the fleet by selling the carrier for scrap. Unlike 2015, where four vessels were flagged for conversion to either become an FLNG or floating storage unit, there were no carriers nominated for any conversions in 2017. One problem that potential conversion candidates are running into is size, as most modern FLNG, FSRU, or floating storage unit projects are looking for at least 150,000 cm of storage capacity. Most conversion candidates are well below this capacity level.

5.3. Charter Market

Overall spot charter rates for most of 2017 remained low at around $23,500/day for conventional steam carriers and $37,000/day for DFDE/TFDE carriers. The delta between charter rates for older steam turbine carriers and newer DFDE/TFDE carriers has remained as charterers overwhelmingly prefer the larger and more fuel-efficient carriers, while charter rates for ships utilizing ME-GI and XDF systems are even higher than those for DFDE/TFDE carriers owing to the increased efficiency of the newer technologies. Notably, toward the end of the year, there was a significant uptick in charter rates; those for conventional steam carriers reached an average $44,300/day, and rates for DFDE/TFDE carriers

Figure 5.6: Average LNG Spot Charter Rates versus Vessel Deliveries, 2012–2017



Source: IHS Markit

reached an average $81,700/day. Strong winter demand in Asia resulted in an increase in cross-basin trade, putting strain on carrier availability. China's environmental mandate to switch from coal to gas left it with a gas shortage toward the end of the year, and Chinese LNG buyers increased spot purchases accordingly. As a result of this and other factors, northeast Asian spot LNG prices rose, prompting Atlantic Basin volumes to flow to the Pacific Basin. These longer-haul voyages kept the Atlantic Basin carrier market very tight during the 2017-18 winter, with multiple weeks going by with no carrier availability in the region. The uptick in rates at the end of the year led charter rates averaged over the entire year to increase YOY in 2017, with the average annual rate reaching $26,700/day for steam carriers and $44,000/day for DFDE/TFDE carriers (representing a 30% and 32% increase over annual 2016 rates, respectively).

Still, for the greater part of 2017 (the first nine months), spot charter rates for conventional steam carriers and for DFDE/TFDE carriers were at historic lows. Several factors kept spot market rates at this level:

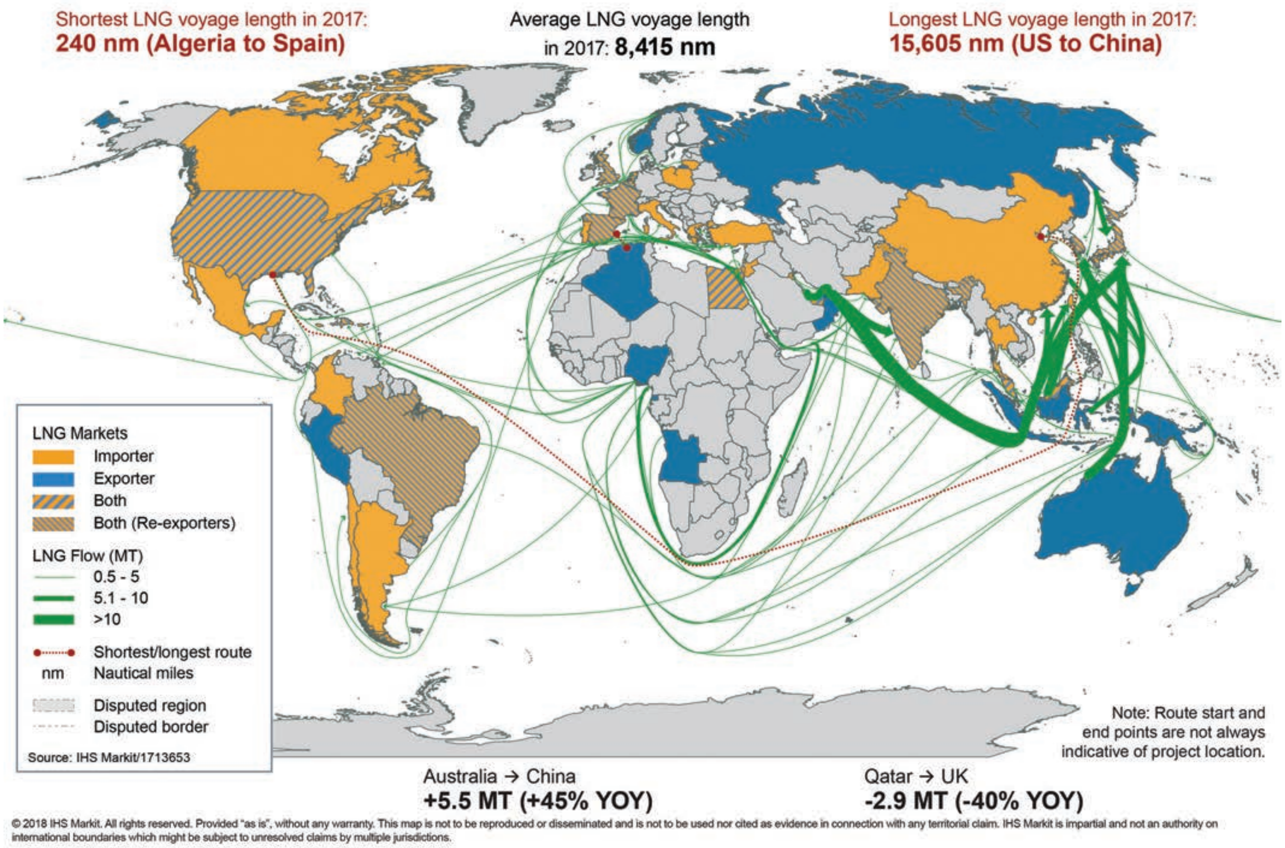
- The global trade has become more regionalized as the arbitrage between markets east and west of the Suez Canal was tight for most of the shoulder and summer months. Spot LNG price differentials between Northeast Asia and NBP were below $1.00/MMBtu for most of 2017, well below roundtrip shipping economics.
- The 2017 addition of 27 new vessels into the global fleet kept up with the 22.3 MTPA of new liquefaction capacity that came online during 2017. This lines up with the industry assumption that one carrier is needed for each 1 MTPA of liquefaction capacity using an average route length; however, around 60% of the new liquefaction capacity was located in the Pacific Basin and will service Northeast Asian markets, resulting in relatively short voyages.

The more dramatic increase in spot charter rates in the last quarter of the year had day-rates reaching levels not seen in over three years, with a distinct basin differential. DFDE/TFDE carrier day-rates in the Atlantic Basin reached an average $85,000/day by the end of 2017, and an average $80,000/day in the Pacific Basin; this represents a 200% increase from the lows hit earlier in the year.

LNG traders have continued to play a critical role in balancing excess tonnage. The number of spot fixtures continues to grow with both traders and portfolio players trying to secure vessels for single voyages. Traders, still reluctant to take a long-term position on shipping, continue to use the spot carrier market to meet their shipping requirements. As the market becomes more liquid, short-term fixtures will be more prevalent. Aggregators are also tapping into the carrier market to fill the gaps in their carrier fleets as they move LNG from the Atlantic to the Pacific Basin. There were close to 370 spot fixtures during 2017 – a 36% YOY increase – with the bulk of fixtures for DFDE/TFDE carriers. This is further evidence of the market's preference for the newer, larger, and more fuel efficient TFDE/DFDE, ME-GI, and XDF carriers.

With trading margins contracting as LNG prices face downward pressure, charterers are trying to cut costs where they can.

Figure 5.7: Major LNG Shipping Routes, 2017



Source: IHS Markit.

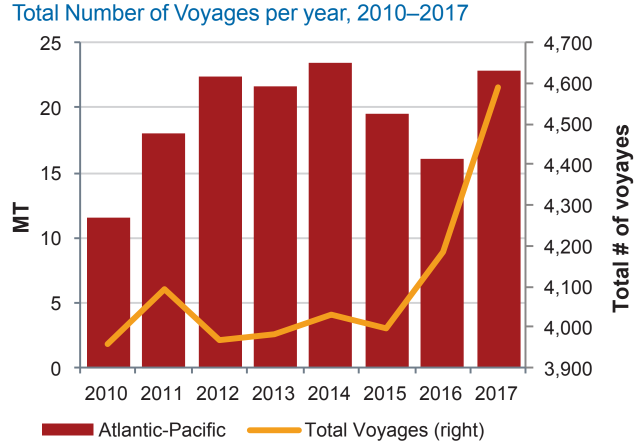
DFDE/TFDE carriers offer superior boil-off rates and consume around 30% less fuel oil than a steam carrier consumes at 18 knots. DFDE/TFDE carriers, even with higher spot charter rates, still offer overall larger savings when boil-off and fuel consumption are taken into consideration. The newer XDF and ME-GI LNG carriers are also being offered in the spot carrier market, which have even greater fuel and boil-off efficiencies. As these newer carriers capture most of the spot trade, older steam carriers are left to sit idle with longer periods of time between cargoes, causing the storage tanks and associated cryogenic equipment to become warm. This requires the vessel to take in cool-down volumes to return to service, which adds time and expense.

Looking forward to 2018, a pullback in cross-basin trade following the winter demand season should result in increased available tonnage in the carrier market, placing downward pressure on charter rates. Global LNG trade is set to continue its regionalisation, as new liquefaction capacity comes online in both the Atlantic and Pacific Basin. These new volumes will keep prices in both basins at parity, reducing the need for cross-basin trade. Ship owners may potentially start looking with more interest at converting some of their existing carriers into FSRUs or floating storage units. The retirement or conversion of older tonnage could provide some relief to this oversupplied market; however, it will take multiple years to work through excess tonnage in a meaningful way.

5.4. Fleet Voyages and Vessel Utilisation

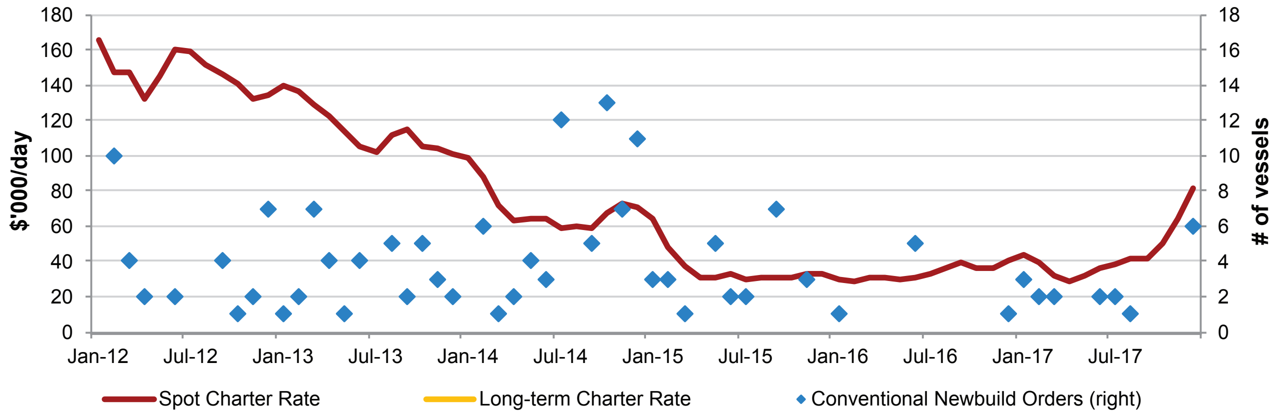
As new liquefaction capacity continued to come online in 2017, the total number of voyages completed during the year continued to increase, with both Asian and European markets helping to absorb new supply. A total of 4,591 voyages were completed during 2017, a 10% increase when compared to 2016 (see Figure 5.8). Trade was traditionally conducted on a regional basis along fixed routes serving long-term point-to-point contracts, though the rapid expansion in LNG trade

Figure 5.8: Atlantic-Pacific Trade versus Total Number of Voyages per year, 2010–2017



Source: IHS Markit

Figure 5.9: Estimated Long-term and Spot Charter Rates versus Newbuild Orders, 2012–2017[5]



Source: IHS Markit

over the past decade has been accompanied by an increasing diversification of trade routes. However, with new liquefaction capacity coming online in the US Gulf Coast, and the Panama Canal expansion fully operational, inter-basin trade was on the rise in 2017, increasing 35% YOY.

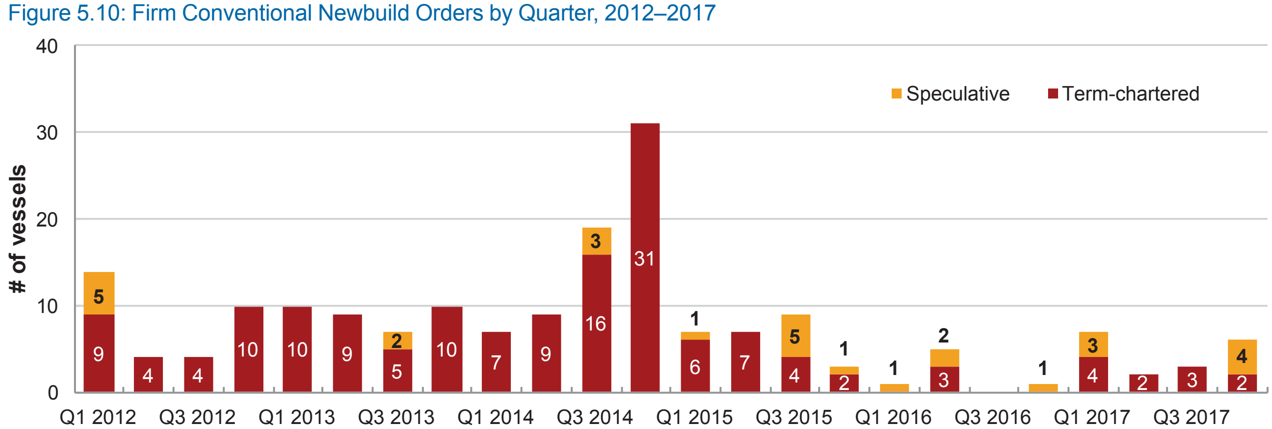
4,591 Voyages
Number of voyages of LNG trade voyages in 2017

With the Panama Canal expansion finally completed, the voyage distance from the US Gulf Coast to Japan has now been reduced to 9,500 nautical miles (nm), compared to 14,400 nm when the Suez Canal is used. However, congestion at the canal has caused cargoes with more flexible discharge windows to take the longer route via the Suez Canal or the Cape of Good Hope. This includes the longest voyage undertaken in 2017, from the US to China around the Cape of Good Hope – a distance of 15,605 nm. It is expected that the Panama Canal Authority will increase slots for LNG carriers as they get more operational experience with these types of carriers. The shortest voyage was a more traditional route from Algeria to Spain, though this occurred only four times during the year. The most common voyage in 2017 was from Australia to Japan, with 290 voyages completed during the year.

In 2017, the amount of LNG delivered on a per carrier basis, including idle carriers, reached 0.62 MT. This compares to the 0.73 MT delivered per carrier in 2011, before the carrier buildout cycle began. Although 2017 deliveries were more evenly matched with the buildout in new liquefaction capacity, the holdover from outmatched deliveries in the previous several years has maintained increased carrier availability. 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. Strong Atlantic to Pacific trade continued in the following three years as traders capitalised on the arbitrage opportunity between basins. The extended voyage distance between the Atlantic and Pacific put a strain on the global LNG fleet, which caused charter rates to skyrocket and led ship owners to put in orders on a speculative basis. With the expected slowdown in new deliveries, average carrier utilization should increase over the next few years.

Carrier availability has remained high since 2014, as the build-up in LNG liquefaction capacity lagged the influx of newbuilds to the market. This continued influx of new tonnage resulted in spot charter rates hitting historic lows during 2017. The seasonality of the LNG trade usually results in a slight increase in day rates during the peak heating season in the winter and cooling season in the summer, with day rates

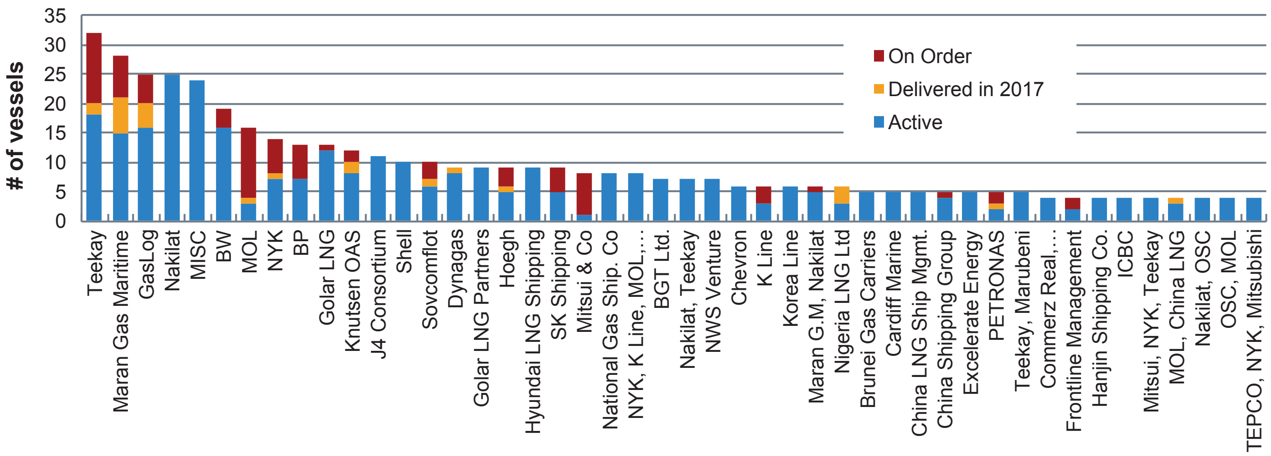
Figure 5.10: Firm Conventional Newbuild Orders by Quarter, 2012–2017



Sources: IHS Markit, Shipyard Reports

[5] Long-term charter rates refer to anything chartered under a contract of five years or above. Spot charter rates refer to anything chartered under a contract of six months or less.

Figure 5.11: LNG Fleet by Respective Company Interests, end-2017



Source: IHS Markit

undergoing a correction during the shoulder months of the LNG demand cycle. However, during the 2017-2018 winter, demand for spot tonnage was exacerbated by China's appetite for spot LNG volumes. Spot LNG prices rose on the back of Chinese winter demand, which resulted in an uptick in cross-basin trade. Tepid Atlantic Basin LNG demand allowed for LNG volumes to be sold into the Asian markets, but the long voyage to the Pacific put a strain on the spot carrier market, resulting in a 200% increase from their lows earlier in the year. A market correction was underway by early 2018, with spot charter rates falling off their winter highs.

5.5. Fleet and Newbuild Orders

At the end of 2017, 106 vessels were on order. Around 81% of vessels in the orderbook were associated with charters that extend beyond a year, while 20 vessels were ordered on a speculative basis (see Figure 5.10).

In 2017, newbuild vessel orders increased by 157% YOY to 18, four of which were for FSRUs. With the perception of a looming supply glut, many liquefaction projects have postponed taking FID, delaying any decision on potential newbuilds. Also, with an order book heavy with speculatively ordered tonnage, many potential project offtakers could easily cover their shipping requirements with these carriers. However, looking past 2018 newbuild deliveries, the order book starts to thin out quite a bit. With the propensity to favour the more fuel-efficient DFDE/TFDE, ME-GI, and XDF carriers over steam turbine carriers, and with the first generation of LNG carriers starting to look like potential scrap or conversion candidates, the carrier market could tighten up in the medium term, post-2022. The idea of a potentially tighter mid-term shipping market seems to have taken hold toward the end of the year, as 6 of the 18 newbuild orders occurred in December 2017, four of which were on a speculative basis. Further, an additional nine carriers were ordered in the first quarter of 2018.

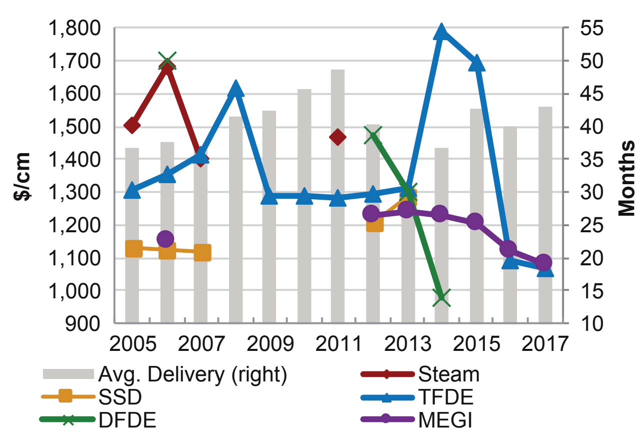
Many independent shipping companies made moves to dramatically grow their fleet sizes in the aftermath of the Fukushima nuclear crisis. While Golar ordered newbuilds primarily on a speculative basis, others such as Maran Gas Maritime and GasLog LNG chiefly placed orders based on term charter agreements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

Out of the 86 vessels on charter in the order book, 19% are tied to companies that would traditionally be considered an LNG producer (e.g., PETRONAS, Yamal LNG, etc.; see Figure 5.11), though these lines are blurring as more producer companies are branching into LNG buying and trading. Traditional LNG buyers make up 23% of the new-build orders as the companies gear up for their Australian and US offtake. The remaining charters comprise companies with multiple market strategies, including traders and aggregators.

5.6. Vessel Costs and Delivery Schedule

Throughout the 2000s, average LNG carrier costs per cubic metre remained within a narrow range. The rapid growth in demand for innovative vessels starting in 2014, particularly vessels with TFDE propulsion, pushed average vessel costs to rise from $1,300/cm in 2005 to $1,770/cm in 2014 (see Figure 5.12). This was mainly driven by the Yamal LNG icebreaker vessels, which are more expensive than a typical carrier. However, in 2017, the costs for TFDE and ME-GI vessels dropped back to $1,072/cm and $1,082/cm, respectively. Korean shipyards, which have been suffering from the overall downturn in shipping, have been quite aggressive with their pricing, in turn forcing Japanese and Chinese shipyards to also offer competitive bids for newbuilds.

Figure 5.12: Average Delivery and Cost per Cubic Meter in Ordered Year by LNG Carrier Type, 2005–2017



Source: IHS Markit

With few exceptions, 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 carriers delivered between 2006 and 2010 experienced an average time of 50 months between order and delivery, but improved to 37 months post-2010. Also, if a shipowner orders a sister ship, the delivery time can be cut down substantially to less than 24 months, since those orders involve minimal design changes.

The Yamal LNG project will require 15 ice-breaker LNG carriers that have already been ordered, with 5 already delivered in 2016 and 2017. These ships have the capacity to transport LNG in summer via the North Sea Route (NSR) and in winter by the western route to European terminals, including Zeebrugge and Dunkirk. These ice-breaking carriers each cost approximately $320 million. As of December 2017, the first of these vessels loaded at the Yamal LNG project.

5.7. Near-Term Shipping Developments

Emissions Reduction

By 2020, International Maritime Organization (IMO) regulations to reduce sulphur emissions to 0.5% for global marine fuels will go into effect. There are three main methods to comply with the cap, which come with trade-offs between up-front capital costs and fuel costs. The simplest method to meet this emissions cap is to use a cleaner liquid fuel. Although this requires few changes to widely understood ship propulsion technology, the compliant fuels are expected to be considerably more expensive. A second compliance option is to install scrubbers that will remove the sulphur from the exhaust gases, since the standard is an emissions standard, and not a fuels standard. The scrubber installation requires some capital expense, but then shippers can continue to burn cheaper high-sulphur fuels.

The third option is to power the ship with much cleaner LNG. In most cases this is the most capitally-expensive option, requiring significant retooling if not complete replacement of the ships' engines, which will typically make it a more feasible option for newbuild rather than existing vessels. The lower volumetric energy density of the fuel also leads to lower utilisation of the shipping volume. However, using LNG also comes with the benefits of having what is expected to be a lower cost fuel, with significantly lower NOx and CO_2 emissions depending on the technology applied.

LNG bunkering infrastructure is already being developed along major trade routes, in ports like Zeebrugge, Rotterdam, and Singapore. These LNG bunkering ports are serviced with small-scale LNG bunker ships, such as the 5,000 cm ENGIE Zeebrugge. With LNG supply growth, producers will welcome any incremental demand from new sources. In a positive move for the expansion of LNG bunkering, the French shipping group CMA CGM ordered nine large-scale LNG-powered containerships in 2017, which will be the world's largest once built.

Emerging markets utilizing vessels for creative import solutions

Jamaica imported its first LNG cargoes in 2016 through new LNG regasification infrastructure delivering to the converted Bogue power plant. The process involves a series of ship-to-ship transfers from conventional LNG carriers to a floating storage unit stationed offshore, then to a lightering vessel set to deliver smaller volumes to an onshore regasification receiving centre. This process is similar to the one first established at Chile's Mejillones terminal, which used a floating storage unit in combination with onshore regasification capacity to allow imports to begin before terminal's onshore storage tank was completed. Jamaica's path to LNG imports highlights a potential trend in the LNG industry – that of smaller, immature markets joining the global LNG space by utilising idle existing infrastructure to develop small-scale projects relatively quickly. Similarly, Malta became an LNG importer in January 2017 by also utilising an older carrier as a floating storage unit and then sending volumes onshore to a small-scale regasification terminal.

Looking Ahead

Will the recovery in the LNG shipping market be sustained? The spot shipping market had an active 2017, and towards the end of the year spot charter rates increased to levels not seen in over three years. This is partly due to a seasonal uplift caused by strong winter demand in Asia. A pullback in cross-basin trade following the winter demand season should result in increased available tonnage in the carrier market, which has already been reflected in late Q1 2018 charter rates. However, over the next three years, an additional 93 MTPA of new liquefaction capacity will come online, while the shipping orderbook has stagnated during the past two years. Over 100 ships on order are nearing delivery in the next few years, but most of them are already dedicated to projects, leaving few shipping options for traders. LNG trade has never been perfectly optimal owing to the complex contractual relationships and company portfolios that dictate marketing strategies (as illustrated by laden carriers passing each other as they cross the Suez); if this continues along with the scrapping of older tonnage, the shipping market could grow tighter.

How will preferences for carrier propulsion systems evolve? Conventional steam carriers continue to be overshadowed by DFDE/TFDE carriers, the latter of which have been overwhelmingly preferred by LNG players in the last few years. With slim trading margins due to low commodity prices, traders are looking to save on whatever components of the trade they can control, and shipping is a prime prospect for rationalization. The gap between charter rates for the more fuel efficient DFDE/TFDE carriers and steam carriers has continued to grow in 2017. The preference for the newer DFDE/TFDE carriers has left many older steam carriers sitting idle for quite some time, resulting in expired Ship Inspection Report Programme (SIRE) documents and warm tanks; this makes them less marketable for spot trades and widens the gap between the two carrier types. The resulting increase in steam tonnage availability has many ship owners looking for alternative uses for their carriers, such as floating storage unit, FSRU, and FLNG conversions.

6. LNG Receiving Terminals

Global LNG regasification capacity continued a trajectory of growth in 2017, topping 851 MTPA as of March 2018. Following a similar trend as the year prior, growth in global receiving terminal capacity was exclusively based in existing markets in 2017. China, Egypt[1], France, Malaysia, Pakistan, South Korea, and Turkey all had terminals reach commercial operations during 2017. The Dunkirk terminal in France (9.5 MTPA), which began commercial operations in January 2017, is the largest terminal to come online in five years. In addition, Thailand and Singapore each completed expansion projects at existing regasification terminals. Although its terminal is considered small-scale, Malta began LNG imports in 2017 utilising a floating storage unit, becoming the only new country to join the LNG market during the year.[2] As a whole in 2017, a mix of onshore, offshore, and expansions to existing terminals combined to add 45 MTPA of regasification capacity to the global market.[3]

In combination with the growth of liquefaction capacity, the LNG market is also experiencing growth in regasification capacity, both in new and existing LNG importing markets. Potentially lower global LNG prices over the next few years could unlock previously unattainable pockets of demand around the world. In the near term, well over half of the anticipated growth in regasification capacity is expected in existing Asian LNG importing countries, namely China and India. Existing importers Japan and Taiwan are also projected to add further receiving capacity in the next two years. Although only very limited amounts of LNG receiving capacity in new importing countries have been added since 2015, a swath of new markets have announced proposals to join the LNG market within the next few years. Bahrain, Bangladesh, Côte D'Ivoire, Ghana, Myanmar, the Philippines, Panama, and Russia (Kaliningrad) all have proposals for regasification capacity announced to come online in the near term. Further out, Australia, Croatia, Germany, Hong Kong (China), Ireland, Lebanon, Morocco, South Africa, Sudan, and Vietnam have all announced receiving terminal projects to come online by the end of 2022. However, many of these markets face significant challenges in financing and implementing these proposals, and a number of the projects have been delayed multiple times. Nonetheless, the addition of new importers to the global LNG market is slated to continue and will be important for a market expecting growing supply.

6.1. Overview

In 2017, all of the new regasification capacity that came online was constructed in existing LNG markets. China, Egypt, Malaysia, and Pakistan all completed new terminals. Singapore and Thailand constructed regasification capacity expansions to existing plants during the year. In addition, France, South Korea, and Turkey all completed terminals that reached commercial operations in January 2017. China's 2.9 MTPA Tianjin (Sinopec) terminal began imports in February 2018, followed by Japan's 1.5 MTPA Soma terminal in March 2018. In sum, these additions brought total LNG regasification capacity in the global market to 851 MTPA across 35 countries (see Figure 6.1).

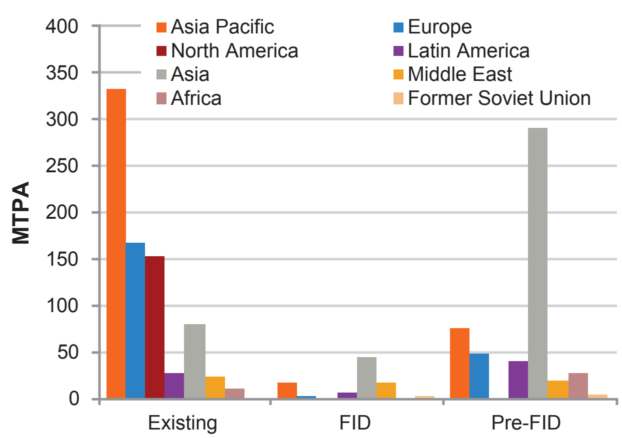
851 MTPA
Global LNG receiving capacity, March 2018

The Asia and Asia Pacific regions[4] contain the highest volume of regasification capacity in the global market. The two regions are anticipated to continue their high rates of capacity expansion moving forward, in both growth markets as well as established LNG importers. Despite having high levels of existing regasification capacity, North America has not experienced capacity growth in recent years, outside of small-scale projects in the Caribbean region. The introduction of FSRUs have allowed several new countries to access the global LNG market over the last decade, especially in the Middle East, Asia, and Latin America. FSRUs are expected to continue to play an important role in bringing LNG imports to new countries quickly, provided there is sufficient pipeline and offloading infrastructure in place. However, onshore regasification terminals offer the stability of a permanent, larger-scale solution when desired and time is available.

6.2. Receiving Terminal Capacity and Utilisation Globally

In 2017, 45 MTPA of new regasification capacity was constructed, an increase of 60% over 2016 additions. This growth rate is higher than that of the previous year, when new capacity additions were only 47% higher than 2015. Notably,

Figure 6.1: LNG Receiving Capacity by Status and Region, as of March 2018



Sources: IHS Markit, Company Announcements

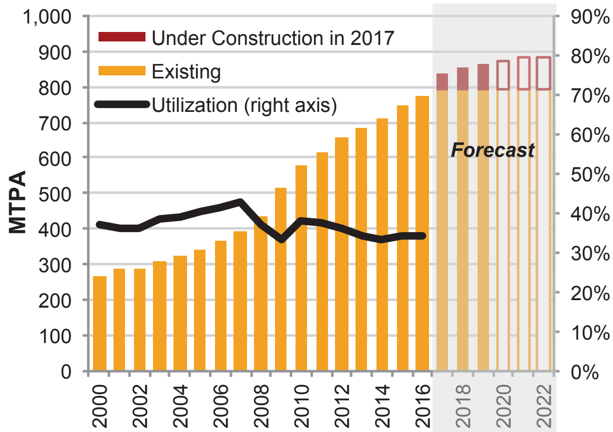
[1] To commission its new terminal location at the port of Sumed, Egypt moved one of the FSRUs it had previously docked at a terminal at the port of Ain Sokhna. Thus, the country did not add new regasification capacity.

[2] All counts and totals within this section only include countries with large-scale LNG regasification capacity (1 MTPA and above). This includes countries that only regasify domestically-produced LNG, which may cause totals to differ from those reported in Chapter 3: LNG Trade. Refer to Chapter 11: References for a description of the categorization of small-scale versus large-scale LNG.

[3] Some individual capacity numbers have been restated over the past year owing to improved data availability. This may cause global capacity totals to differ compared to the IGU World LNG Report – 2017 Edition.

[4] Please refer to Chapter 11: References for an exact definition of each region.

Figure 6.2: Global Receiving Terminal Capacity, 2000–2023



Note: The above forecast only includes projects sanctioned as of March 2018. Owing to short construction timelines for regasification terminals, additional projects that have not yet been sanctioned may still come online in the forecast period, as indicated by the outlined bars. Although several FSRU contracts will expire over this period, this forecast assumes that the capacity will remain in the global market. Sources: IHS Markit, IGU, Company Announcements

new regasification capacity in 2017 was only constructed at existing markets, marking the first time in ten years without a new regasification market[5]. Still, the number of countries with import infrastructure has expanded significantly in recent years, more than tripling over the past 15 years. Increasingly flexible supply has supported LNG trade growth, and in recent years, FSRUs played a larger role in allowing new markets to access LNG supply at a faster rate. LNG trade growth has also benefited from lower global LNG prices, driving demand in countries such as India, as well as measures for reduction in air pollution, as observed in China. A large portion of the next group of LNG importers anticipated to join the global LNG market are from emerging, higher credit risk regions. However, some new countries from established importing regions, including Europe, continue to commence their first imports.

Over the course of 2017, seven new regasification terminals reached commercial operations (see Figure 6.3). Four of the new terminals were completed in the Asia or Asia Pacific regions, including in China (Yuedong), Pakistan (PGPC Port Qasim), Malaysia (RGT2 Pengerang), and South Korea (Boryeong). In Europe, France's Dunkirk terminal and Turkey's Etki terminal began commercial operations in January 2017. Egypt also moved an existing FSRU within the country to commence operations at the new Sumed BW regasification terminal. In total, 34.7 MTPA of regasification capacity was added in new terminals in 2017.

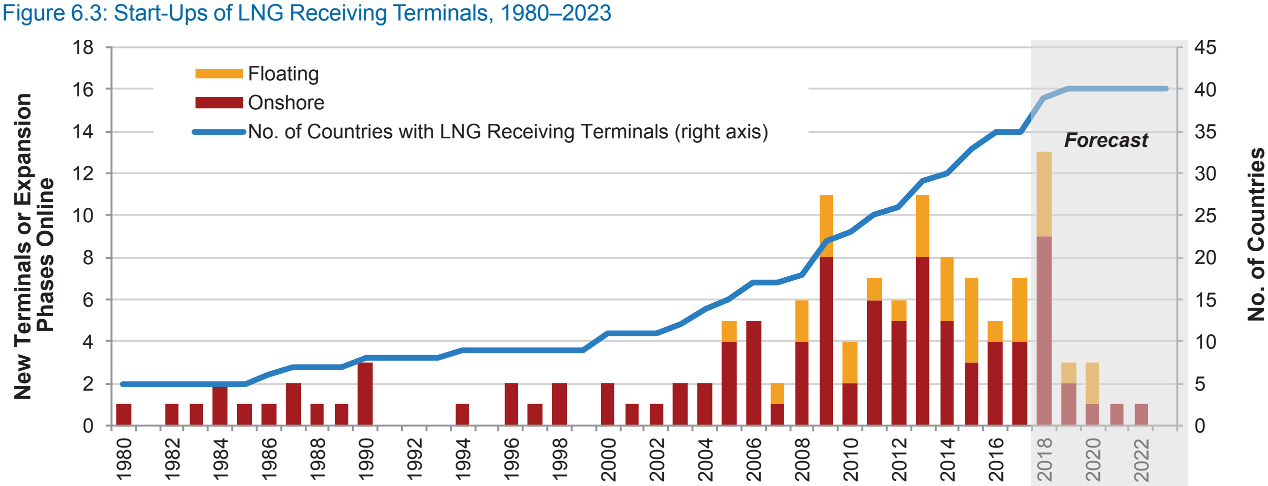
7 terminals
Number of new receiving terminals brought online in 2017

Beyond the new terminal projects, two expansion projects were completed at existing regasification terminals in 2017. Thailand's Map Ta Phut terminal added 5 MTPA of capacity, expanding the terminal's total regasification capacity to 10 MTPA. Singapore's regasification terminal also added 5 MTPA of capacity, increasing to a total of 11 MTPA of capacity (though the associated expansion of storage capacity was not expected to be complete until 2018). The 10 MTPA of expansion projects, in combination with the 34.7 MTPA of new terminals, brought total added regasification capacity in 2017 to 44.7 MTPA. Furthermore, China began imports at a 2.9 MTPA terminal in Tianjin in February 2018 and Japan completed a 1.5 MTPA terminal in March 2018.

As of March 2018, 87.7 MTPA of new regasification capacity was under construction, including twelve new onshore terminals, seven FSRUs, and eight expansion projects to existing receiving terminals. Although 81% of this total capacity will be in existing import markets, five under-construction projects are anticipated to add capacity for the first LNG imports in Bahrain, Bangladesh, Panama, the Philippines, and Russia (Kaliningrad). China has seven terminals under construction, along with four expansion projects, while India has four new terminal projects. Additional terminal construction and regasification capacity expansion projects are underway in Turkey, Greece, Belgium, Taiwan, Brazil, and Kuwait.

Beyond under-construction projects, two FSRU projects were in advanced stages.[6] The projects are to be located in Ghana

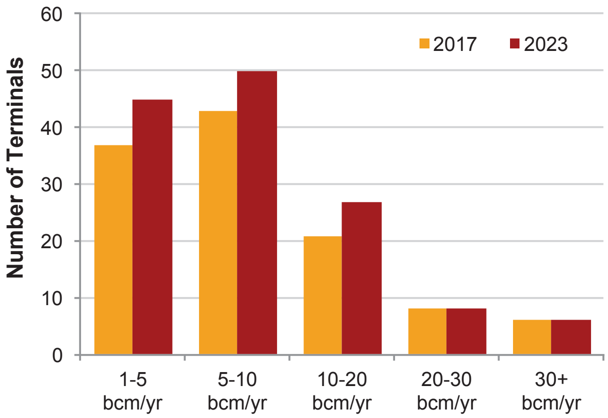
Figure 6.3: Start-Ups of LNG Receiving Terminals, 1980–2023



Sources: IHS Markit, Company Announcements

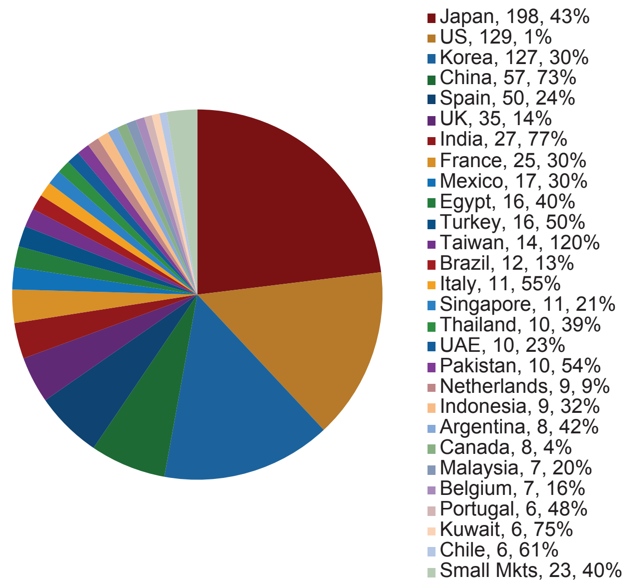
[5] Although Malta began LNG imports in 2017, its terminal is small-scale and thus not included in this chapter.
[6] Although these projects technically have binding agreements in place with FSRU providers, they are still considered as "Pre-FID" until on-site construction is confirmed.

Figure 6.4: Annual Send-out Capacity of LNG Terminals in 2017 and 2023



Sources: IHS Markit, Company Announcements

Figure 6.5: LNG Regasification Capacity by Country (MTPA) and Regasification Utilisation, March 2018



Note: "Smaller Markets" includes (in order of size): Jordan, Poland, Greece, Lithuania, Israel, Colombia, Dominican Republic, and Puerto Rico. Each of these markets had 4 MTPA or less of nominal capacity as of March 2018. Regasification utilisation figures are based on 2017 trade data. Sources: IHS Markit, IGU

and Chile, with a total combined capacity of 7.4 MTPA. The FSRU in Ghana is set to be the first regasification terminal in the country, announced to come online in late 2019.

87.7 MTPA
New receiving capacity under construction, as of March 2018

In 2017, the global LNG market experienced regasification utilisation levels at an average of 35%, which is approximately equivalent to utilisation levels recorded in 2016. If mothballed terminals[7] are excluded, this number would reach 38% in 2017. Onshore regasification terminals operated at 34% of capacity in 2017, compared to 47% of capacity for FSRUs throughout the year. Due to the requirement to meet peak seasonal demand and ensure security of supply, regasification terminal capacity far exceeds liquefaction capacity. Although 44.7 MTPA of regasification capacity was added in 2017, the average levels of global regasification utilisation remained essentially flat. However, if the U.S. is removed, global regasification utilisation reached 41% in 2017. The U.S. imported about 1.5 MT, largely underutilizing its regas capacity of 126 MTPA, as gas production from shale has expanded.

Average send-out capacity has followed a trajectory of decline over the last few years, largely because of small- to medium-sized terminals coming online in smaller markets, as well as the growing use of floating terminals, whose capacity is generally below 6 MTPA. Average regasification capacity for existing onshore terminals stood at 7.8 MTPA as of March 2018, compared to 4.2 MTPA for floating terminals. Global average send-out capacity has fallen from 12.2 billion cubic meters per year (bcm/yr; equivalent to 8.9 MTPA) in 2011 to 9.7 bcm/yr (7.0 MTPA) in 2017 (see Figure 6.4).

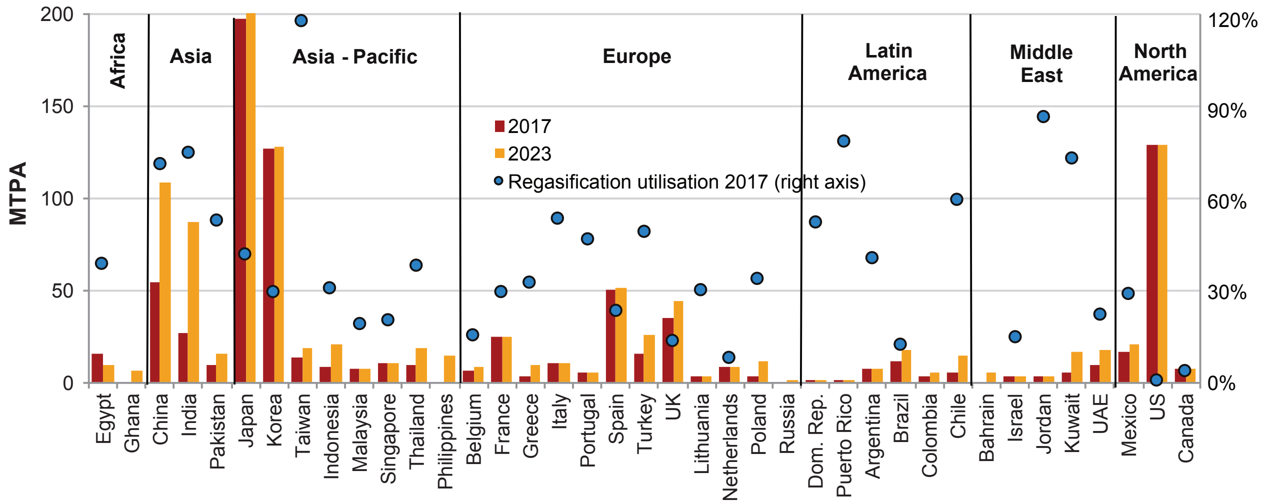
6.3. Receiving Terminal Capacity and Utilisation by Country

The world's biggest LNG importer, Japan, also contains the highest regasification capacity of any LNG importing country,

Huelva – Courtesy of Enagas

[7] Including El Musel, Cameron, Golden Pass, Gulf LNG, and Lake Charles.

Figure 6.6: Receiving Terminal Import Capacity and Regasification Utilisation Rate by Country in 2017 and 2023.



Sources: IHS Markit, IGU, Company Announcements

despite not adding any additional terminals in 2017 (see Figure 6.5). However, Japan completed the 1.5 MTPA Soma terminal in March 2018. The country's regasification capacity stood at 197 MTPA in 2017, equal to 15% of total global regasification capacity. At year end, Japan's regasification utilisation reached 43%, level with the same figure in 2016. The addition of the Soma terminal brought the country's total capacity to 198.5 MTPA in early 2018.

China became the second largest LNG import market in 2017, surpassing South Korea, and continues to be one of the fast-growing LNG markets for regasification capacity.

China added 2.6 MTPA of regasification capacity in 2017, following the addition of 12 MTPA in 2016. China's 2.9 MTPA Tianjin (Sinopec) terminal also began imports in February 2018. In addition, the country has 27.3 MTPA of regasification capacity under construction as of March 2018. In terms of total regasification capacity, China is the fourth largest market in the world, at 54 MTPA in 2017. Notably, this is up from only 6 MTPA in 2008. China's regasification utilisation rose significantly in 2017, reaching 73% (up from 56% in 2016) on the back of significantly higher imports as the country sought to reduce air pollution through coal-to-gas switching.

2016-2017 Receiving Terminals in Review

Receiving Capacity **+45 MTPA** Growth of global LNG receiving capacity	New LNG import terminals **+4** Number of new onshore regasification terminals	New LNG Offshore terminals **+3** Number of new offshore LNG terminals	Number of regasification markets **+0** Markets that added regasification capacity
Regasification capacity grew by 44.7 MTPA (+5%), from 802 MTPA in 2016 to 847 MTPA in 2017 Growth in capacity was led by the Asia and Asia Pacific regions in 2017 France's 9.5 MTPA Dunkirk terminal reached commercial operations in January 2017, the largest terminal to come online since South Korea's Samcheok terminal in 2014	New onshore terminals were added in China, France, Malaysia, and South Korea Two expansion projects at existing onshore terminals, in Thailand and Singapore, were also completed in 2017 China's Tianjin (Sinopec) terminal also received its first cargo in February 2018, and Japan's Soma terminal began commercial operations in March 2018	Three FSRUs began commercial operations in 2017, in Turkey (Etki), Egypt (Sumed BW), and Pakistan (PGPC Port Qasim) An additional FSRU arrived at the Dortyol terminal in Turkey, with operations expected to commence in early 2018 Malta's FSU began operations in 2017, although this is considered to be a small-scale project	The number of countries with regasification capacity remained steady at 35 in 2017, following the addition of Poland and Colombia in 2016. Malta began LNG imports in 2017, although the terminal is small-scale Russia (Kaliningrad), the Philippines, Ghana, Panama, Bangladesh, and Bahrain all have their first regasification projects in advanced development stages in 2018, set to come online over the next two years

South Korea, the world's third largest LNG importer in 2017, has 127 MTPA[8] of regasification capacity, behind only Japan and the US. The country added 3 MTPA of capacity after completing the Boryeong terminal in January 2017, but did not have any additional capacity under construction as of early 2018. South Korea experienced a regasification utilisation rate of 30% in 2017; although LNG demand has fallen from its peak in 2013 owing to increased nuclear and coal-fired power, nuclear outages in 2017 led regasification utilisation rates to climb relative to the previous year.

Taiwan remains one of the largest LNG importers, generally importing above its 14 MTPA of nameplate regasification capacity. Although no new terminals have been completed since 2009, Taiwan has announced several proposals to expand regasification capacity by up to 12 MTPA, including a 1 MTPA expansion project at the existing Taichung LNG terminal, expected in 2018. Taiwan's LNG demand has increased incrementally over the last few years as gas utilisation in the power sector rose.

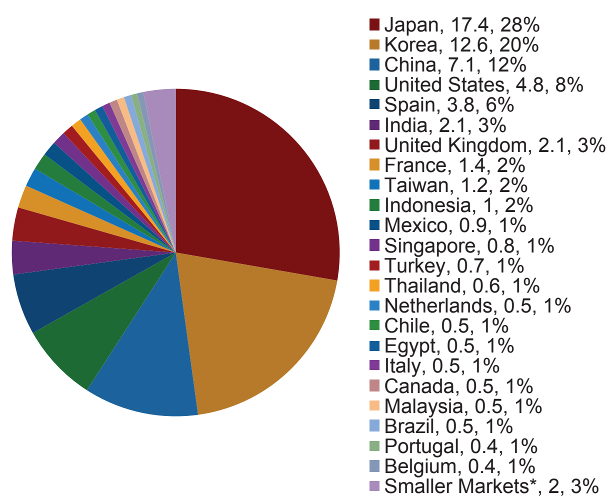
Anticipated to be a significant source of growth for the LNG market, India has 19 MTPA of regasification capacity under construction as of March 2018. The country's 27 MTPA of existing capacity is the seventh largest in the world. Furthermore, there are proposed projects representing 135 MTPA. Eastern India requires additional supply since domestic upstream projects have either under-performed or been delayed. Moreover, new gas-consuming sectors such as refineries, city gas consumption, and other industrial uses are actively being developed. Similar gas development and regasification activity is gaining traction in northeastern and southwestern India as well. Despite this, new pipeline connections will be needed to maximize gas penetration throughout the country. The lack of connectivity near the Kochi terminal in particular has limited throughput thus far and current expectations by the operator are that the pipeline will be completed by 2019 at the earliest.

Although Europe holds roughly 20% of total global regasification capacity, regasification utilisation rates have generally been low, averaging 27% in 2017 (up from 25% in 2016). This figure, however, varies widely by country, ranging from 9% in the Netherlands to 55% in Italy (see Figure 6.6). Competition from pipeline gas coupled with weaker gas demand in the power sector have led to lower regasification utilisation rates in recent years. Record pipeline imports from Russia and Norway have further squeezed LNG in many markets. Nonetheless, LNG imports into Europe increased in 2017 owing to unusually high power demand after a hot and dry summer, reduced hydropower output, and higher coal prices. Domestic gas production in Europe is also on the decline.

Only three new European regasification terminals have been completed in the past three years, in Poland, France, and Turkey. Given low regasification utilisation rates across Europe, significant increases to regasification capacity may not be required despite the anticipation of higher LNG imports into Europe moving forward. The 3.6 MTPA Swinoujscie terminal was introduced in Poland in 2016 to provide diversity of supply. In early 2017, the 9.5 MTPA Dunkirk terminal in France reached commercial operation, becoming the largest regasification terminal to come online in the global market since 2014. The terminal is in France's northeast, near the GATE, Zeebrugge, and Grain terminals, which together equate to 30 MTPA of regasification capacity in a roughly 130-km radius. The Etki FSRU in Turkey became Europe's first FSRU since the Klaipeda FSRU was completed in Lithuania in 2014, adding 5.3 MTPA of capacity in early 2017. Turkey also has an FSRU in place at the forthcoming Dortyol terminal, expected to begin operations in 2018. Russia's FSRU in the Kaliningrad exclave is anticipated online by end-2018, poised to be the country's first regasification terminal. In the medium term, Croatia could potentially become an LNG importer if progress is made on its Krk LNG terminal. Also on the Mediterranean Sea, Greece and Bulgaria are pushing to install an FSRU at Alexandroupolis, which has been aided by the progress on both the Trans-Adriatic Pipeline (TAP) and Interconnector Greece Bulgaria (IGB). In northwest Europe, both Ireland and the United Kingdom have regasification projects proposed by 2020. The 3 MTPA Innisfree terminal in Ireland would be the country's first. Germany has also proposed its first LNG terminal, a 3.6 MTPA project in Hamburg.

The U.S. contains the second highest level of regasification capacity in the world, only trailing Japan. However, the country's terminals remain minimally utilized, if at all; the country averaged 1% regasification utilisation in 2017. In fact, only three of the ten regasification terminals in the US received cargoes in 2017. The prospect of ample, price-competitive domestic gas production means that LNG imports are not expected to increase. Many terminal operators have focused on adding export liquefaction capacity to take advantage of the shale gas boom. Canada also had one of the lowest regasification utilisation levels in 2017 (4%), also due to the availability of domestic production. Taiwan (120%) registered the highest regasification utilisation in 2017 as the country has typically received higher volumes than its announced regasification capacity, often leading to utilisation levels over 100%. In recent years, Puerto Rico has also experienced regasification utilisation figures over 100%. However, the effects of Hurricane Maria reduced utilisation in Puerto Rico to 80% in 2017.

Figure 6.7: LNG Storage Tank Capacity by Country (mmcm) and % of Total, as of March 2018



Note: "Smaller Markets" includes (in order of size): United Arab Emirates, Argentina, Kuwait, Lithuania, Pakistan, Colombia, Jordan, Dominican Republic, Israel, Greece, and Puerto Rico. Each of these markets had less than 0.4 mmcm of capacity as of March 2018. Sources: IHS Markit, Company Announcements

[8] Historical South Korea regasification capacity figures have been restated this year owing to greater data availability.

6.4. Receiving Terminal LNG Storage Capacity

With an anticipation of growing global LNG supply, the strategic importance of natural gas storage is set to expand, especially in Asia and Europe as liquefaction projects in Australia and the US ramp up. Global LNG storage capacity grew to 62.7 million cubic meters (mmcm) through end-2017 following the addition of seven new regasification terminals and one expansion project over the year. The average storage capacity for existing terminals in the global market was 424 thousand cubic meters (mcm) as of early 2018 (see Figure 6.7).

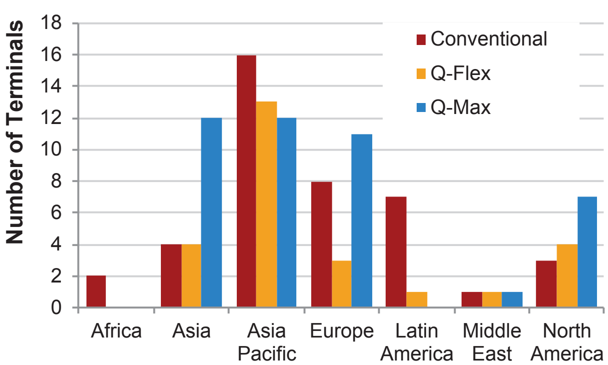
The twenty largest LNG storage terminals in the world range from 0.6 to 3.4 mmcm in size, and comprise over 40% of the global market's total existing storage capacity. Out of the twenty largest LNG storage terminals, nineteen are in the Asia and Asia Pacific regions, as terminal operators in the region placed a premium on large storage capacity to secure supply and enhance flexibility, particularly given Asia's seasonal demand cycles. Importers like China, Japan, India, and South Korea also often have little gas storage available outside of LNG terminals.

The terminal with the largest storage capacity is the Pyeongtaek terminal in South Korea, with capacity to store up to 3.36 mmcm. Capacity in South Korea continues to grow, with the Samcheok terminal's storage capacity increasing to 2.61 mmcm in mid-2017 following the completion of three additional storage tanks of 270,000 cm each – the world's largest capacity for a single storage tank. In addition, the completion of the Boryeong terminal in early 2017 added 0.6 mmcm. Outside of Asia, France's Dunkirk, completed in January 2017, contains 0.57 mmcm of storage.

Storage capacity is following two trends: growth in average storage capacity per terminal in existing markets, particularly onshore terminals in Asia, and decline in average storage capacity in new markets deploying FSRUs, which typically contain far less storage capacity than onshore systems. Onshore terminals generally contain between 200 and 600 mcm of storage capacity, whereas floating terminals typically utilize storage tanks between 125 and 170 mcm in size.

Storage capacity also has other important uses. In addition to storing LNG that is later regasified, storage capacity can also be utilised for transhipment and truck-loading capabilities.

Figure 6.8: Maximum Berthing Capacity of LNG Receiving Terminals by Region, 2017[9].



Sources: IHS Markit, Company Announcements

Although these processes generally require small volumes of LNG, they are expected to comprise a growing portion of LNG demand growth moving forward.

6.5. Receiving Terminal Berthing Capacity

Ship receiving capacities vary widely at different regasification terminals, depending on terminal size, location, and other factors. Much like recent trends in storage capacity figures, onshore facilities have increased their maximum ship berthing capacities to accommodate larger vessels, while new markets deploying FSRUs or small-scale regasification terminals generally have smaller ship berthing capacities. In general, smaller terminals only have the capacity to berth conventional ships, which are under 200,000 cm in capacity. As more established and higher-demand markets have expanded their ship berthing capacities in recent years, the utilisation of Q-Class carriers (those over 217,000 cm) has increased simultaneously.

The biggest LNG carrier vessels, Q-Max vessels, have capacities around 266,000 cm. As of early 2018, 42 out of 121 existing regasification terminals, located in 16 different countries, were known to have the berthing capacity to receive a Q-Max vessel (see Figure 6.8). Of the 42 terminals, 23 were in the Asia or Asia Pacific regions, while the Middle East only has one such terminal, and Latin America and Africa have zero. Q-Flex vessels have a capacity around 217,000 cm. A further 26 regasification terminals had berthing capacities to receive Q-Flex carriers, as well as conventional LNG vessels. Out of 35 total import markets, 20 were confirmed to have a minimum of one terminal with receiving capacity for Q-Class vessels. Notably, Taiwan, the world's fifth largest LNG importer in 2016, is only able to receive conventional vessels. Of the 52 terminals that are reported to be limited to receive conventional vessels, 20 are FSRUs. Some terminals can receive even smaller LNG ships as small-scale LNG facilities continue to develop worldwide; one example is the 0.4 MTPA Montego Bay terminal in Jamaica, which utilizes a 6,500 cm lightering vessel to make ship-to-ship transfers from a conventionally-sized FSU and then shuttle to a small-scale onshore regasification system. Many European terminals are adjusting to accommodate small-scale vessels and add LNG bunkering capabilities to comply with emissions targets and capture new commercial opportunities.

6.6. Receiving Terminals With Reloading and Transshipment Capabilities

Re-exporting LNG grew over recent years as markets with excess access to pipelines took advantage of arbitrage opportunities through LNG trade between basins, as well as specific logistical factors within certain markets. As in 2016, France re-exported the most cargoes in 2017, at 0.75 MTPA, utilising both the Montoir and Fos Cavaou terminals. In previous years, Spain historically produced the most re-exported volumes, but the country shipped just three cargoes over the last two years.

Historically, Europe has generated the greatest volume of re-exports, with France and the Netherlands leading the way in 2017. There are 14 terminals in Europe (out of 26 existing terminals) that are capable of re-exports. Lithuania began re-exports within the region in 2016, although these volumes are small-scale in nature. However, the share of non-European

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

re-exports in the global LNG market has risen in recent years, reaching a high of 40% of total re-exports in 2017, compared to only a few cargoes in previous years. Furthermore, Singapore produced the third most reloaded cargoes, reaching 0.5 MTPA in 2017.

Japan and the Dominican Republic both produced their first re-exports in 2017 via the Sodeshi and Andres terminals, respectively. This follows Singapore and India's first re-exports in 2015. The Andres terminal also added the capability to re-export small-scale volumes to terminals in the Caribbean region. As of March 2018, 26 terminals in 14 different countries have reloading capabilities. Other facilities, such as Cove Point in the US, have been authorized to re-export, but decided not to pursue this option as they have instead focused on adding liquefaction capacity. France's Dunkirk regasification terminal, which began commercial operations in January 2017, also has reloading capabilities, and generated its first re-export cargoes in early 2018.

Terminals with multiple jetties have the ability to complete transshipments and deliver bunkering services, such as the Montoir-de-Bretagne (France) terminal. Multiple terminals in Europe, such as GATE, Barcelona, and Cartagena have been offering this functionality for ships as small as 5,000 cm. Regarding bunkering operations, Cartagena registered the first pipe to jetty operation in Europe in 2017, a direct bunkering operation from a large-scale terminal. For more information on these activities, please refer to Chapter 9: Flexible LNG Facilities: Enhancing Functionality Across the LNG Value Chain.

In addition, the transportation sector is a small but growing portion of LNG demand. Multiple receiving facilities have developed truck loading capabilities, such as Singapore's LNG terminal, which added both truck-to-ship bunkering and LNG truck loading in 2017, in addition to its established conventional bunkering capabilities. In addition, small-scale consumption has increased, reaching isolated demand pockets outside of the primary pipeline infrastructure. For more information on this topic, see the 2015 edition of the IGU World LNG Report.

6.7. Comparison of Floating and Onshore Regasification

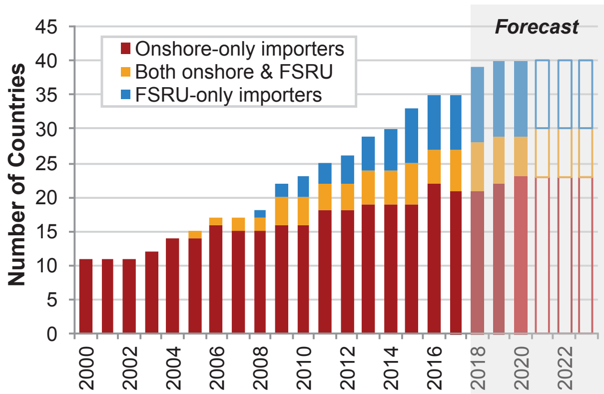
The vast majority of existing regasification terminals are located onshore, amounting to 82% of total global regasification terminals as of March 2018. However, the ratio onshore to offshore terminals has been shifting in recent years. Of the seven terminals that began operations in 2017, only four

Table 6.1: Regasification Terminals with Reloading Capabilities as of March 2018

Country	Terminal	Reloading Capability	Storage (mcm)	No. of Jetties	Start of Re-Exports
Belgium	Zeebrugge	4-5 mcm/h	380	1	2008
Brazil	Guanabara Bay	10.0 mcm/h	171	2	2011
Brazil	Bahia	5 mcm/h	136	1	N/A
Brazil	Pecém	10 mcm/h	127	2	N/A
Dom. Rep.	Andrés	N/A	160	1	2017
France	Fos Cavaou	4.0 mcm/h	330	1	2012
France	**Montoir**	**5.0 mcm/h**	**360**	**2**	**2012**
France	Dunkirk	4.0 mcm/h	570	1	N/A
India	Kochi	N/A	320	1	2015
Japan	Sodeshi	N/A	337	1	2017
Mexico	Costa Azul	N/A	320	1	2011
Netherlands	GATE	10 mcm/h	540	2	2013
Portugal	Sines	3.0 mcm/h	390	1	2012
Singapore	Singapore	8.0 mcm/h	564	2	2015
S. Korea	Gwangyang	N/A	530	1	2013
Spain	Cartagena	7.2 mcm/h	587	2	2011
Spain	Huelva	3.7 mcm/h	620	2	2011**
Spain	Mugardos	2.0 mcm/h	300	1	2011
Spain	Barcelona	4.2 mcm/h	760	2	2014
Spain	Bilbao	3.0 mcm/h	450	1	2015
Spain	Sagunto	6.0 mcm/h	600	1	2013
Spain	El Musel	6.0 mcm/h	300	1	N/A
UK	Isle of Grain	Ship-dependent	960	1	2015
USA	Freeport	2.5 mcm/h***	320	1	2010
USA	Sabine Pass	1.5 mcm/h***	800	2	2010
USA	Cameron	0.9 mcm/h***	480	1	2011

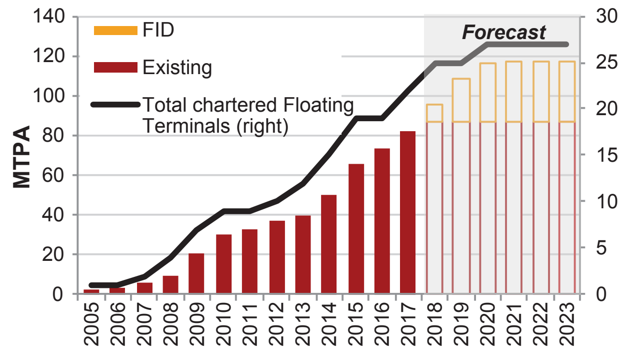
**Lithuania also began re-exports in 2017, but these were small-scale and thus not included in this report.*
***For Huelva, re-loading capabilities began in 1997 with internal reloadings within Spain.*
****Reloading capacity permitted by the US DOE. Sources: IHS Markit, IGU*

Figure 6.9: Rise of FSRUs among Import Markets, 2000–2023



Note: The above graph only includes importing countries that had existing or under-construction LNG import capacity as of end-2017. Owing to short construction timelines for regasification terminals, additional projects that have not yet been sanctioned may still come online in the forecast period, as indicated by the outlined bars. Although several FSRU contracts will expire over this period, this forecast assumes that the capacity will remain in the global market.
Sources: IHS Markit, Company Announcements

Figure 6.10: Floating Regasification Capacity by Status and Number of Terminals, 2005–2023

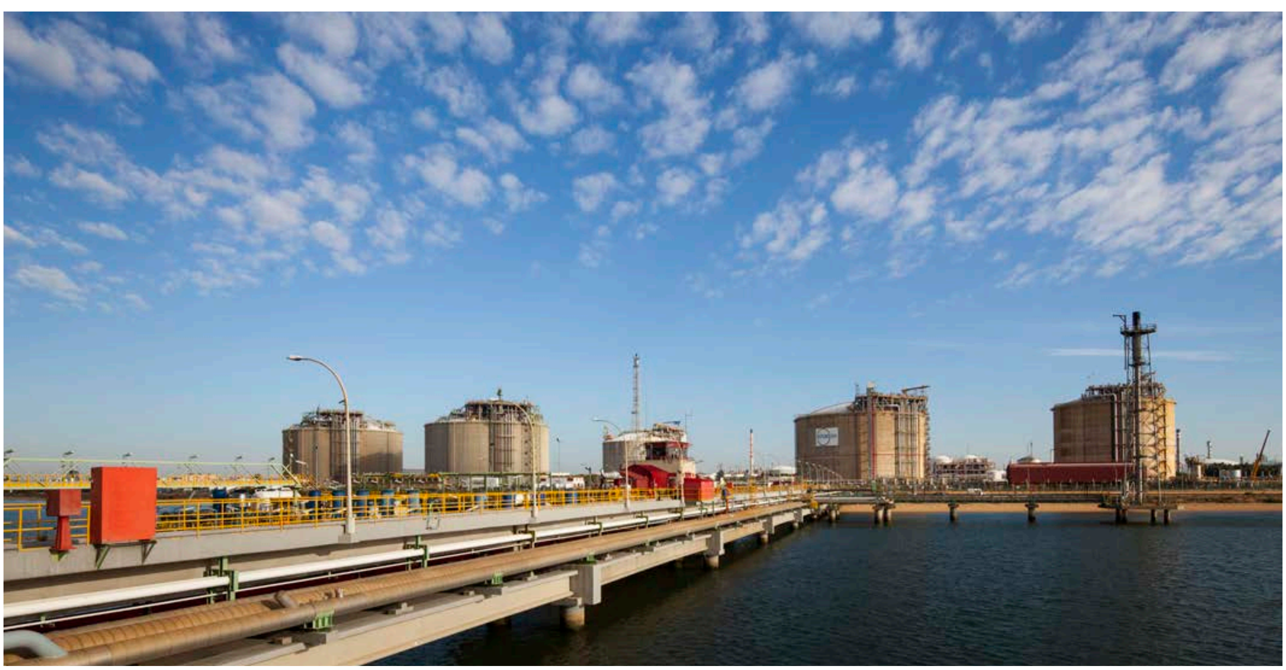


Note: The above forecast only includes floating capacity sanctioned as of end-2017. Owing to short construction timelines for FSRUs, additional projects that have not yet been sanctioned may still come online in the forecast period, as indicated by the outlined bars. Although some FSRU charters may expire in the future, the graph depicts the number of charters at a steady level due to uncertainty over full charter details for each floating terminal.
Sources: IHS Markit, Company Announcements

were onshore developments. Furthermore, only eleven of the nineteen terminals under construction as of early 2018 are listed as onshore proposals. The addition of FSRUs has provided a pathway for a number of new countries to join the global LNG market throughout the last few years (see Figure 6.9). Out of the thirty-five existing LNG import markets in March 2018, fourteen had FSRU capacity, and six of those had onshore capacity as well. Five FSRU projects were under construction or had already selected an FSRU contractor and have announced plans to come online by end-2018, totalling 14.9 MTPA (in Bangladesh, Panama, and Russia (Kaliningrad) – all new LNG markets – and India and Turkey). Furthermore, multiple FSRUs and floating storage units have been announced for 2019, particularly in Bahrain, Ghana, and the Philippines, all of which would be new import markets. Nevertheless, there are still several new importers, such as Hong Kong (China), Ireland, Myanmar, and Sudan, that announced plans to enter the LNG market using onshore proposals to establish a more permanent solution for gas imports.

Three new floating terminals began operations in 2017: Turkey's 5.3 MTPA Etki terminal, Egypt's 5.7 MTPA Sumed BW terminal, and Pakistan's 5.7 MTPA PGPC Port Qasim terminal. The Sumed BW terminal began operations after an existing FSRU at the Ain Sokhna BW terminal in Egypt was moved to Sumed port in mid-2017. At the end of March 2018, total active floating import capacity stood at 84 MTPA at 22 terminals (see Figure 6.10).

FSRUs and onshore terminals each have distinct benefits and drawbacks for regasification utilisation, which often depends significantly on the requirements of the specific target market.



Huelva – Courtesy of Enagas

Table 6.2: Benefits of Onshore Regasification Terminals and FSRUs

Onshore Terminals	FSRUs
Provides a more permanent solution	Allows for quicker fuel switching
Offers longer-term supply security	Greater flexibility if there are space constraints or no useable ports
Greater gas storage capacity	Requires less CAPEX
Requires lower operating expenditures (OPEX)	Depending on location, fewer regulations
Option for future expansions	

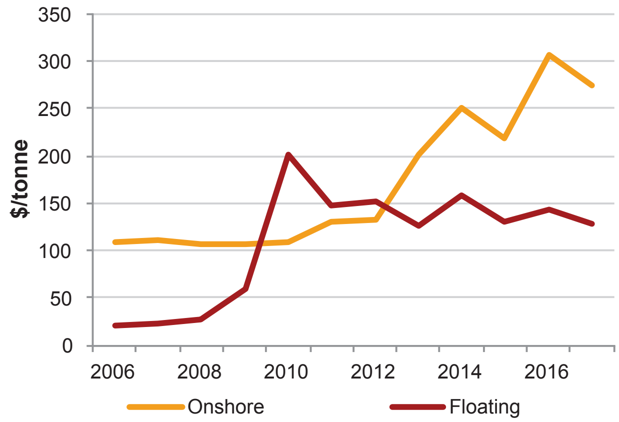
In recent years, a number of first-time importing markets, including Egypt, Jordan, Pakistan, Abu Dhabi, and Colombia, have all joined the global LNG market through the addition of floating regasification. FSRUs can be brought online faster than onshore terminals, allowing for faster fuel switching. This can be important for new markets with an aim to satisfy potential near-term gas demand growth. With FSRUs often chartered from third parties, offshore terminals are typically less capital-intensive than onshore developments, and can often be completed via faster permitting processes (see Section 6.8 for additional information). In many cases, FSRUs allow for greater flexibility in choosing a desired location for a regasification terminal, with fewer space constraints and limited onshore construction requirements.

Depending on target market requirements, onshore terminals can provide several advantages over FSRUs. Storage and send-out capacities can be of strategic importance in many markets, and onshore terminals typically provide the opportunity for larger storage tanks and expansions. Given the location of offshore terminals, floating regasification can face a number of potential risks that are avoided by onshore projects, such as a longer LNG deliverability downtime, vessel performance, and heavy seas or meteorological conditions. FSRUs also may experience limitations or challenges with onloading capacities, which many onshore terminals can circumvent. In addition, depending on the location, onshore projects can permit future on-site regasification and storage expansion plans. For more information on FSRU activity and uses, please refer to Chapter 7: FLNG Concepts: Facts and Differentiators.

There are two separate classification types of FSRUs, based on the vessels' engine capabilities. The first FSRUs came in the form of converted old vessels with limited propulsion that are permanently moored and act as long-term regasification terminals. Other floating terminals are mobile vessels that can be contracted for limited periods. These FSRUs can function as standard LNG carriers when not under contract, and also have the ability to come to a port loaded and stay only for the time required to regasify their cargo.

Nine FSRUs (with capacities over 60,000 cubic meters) were announced to be on the order book as of March 2018. In addition, multiple FSRUs were open for charter around the same time, indicating sufficient near-term floating regasification capacity. However, it is likely that these open vessels will be

Figure 6.11: Regasification Costs Based on Project Start Dates, 2006–2017



*Indicates the size of onshore storage relative to onshore terminal capacity.
Sources: IHS Markit, Company Announcements

chartered to projects imminently, and many of the FSRUs in the order book are already earmarked for specific projects. The value of bringing a new import market online quickly is increasing, as is the number of proposed floating projects. Shipping companies have been open to ordering newbuild FSRUs and converting existing conventional vessels on a speculative basis, underlining the perceived importance of FSRUs in supporting new LNG markets.

6.8. Project CAPEX

Project capital expenditure (CAPEX) for newly completed regasification capacity has followed two separate trends in recent years. Since 2012, the cost of new onshore regasification progressed along a general trajectory of higher costs, while offshore terminal CAPEX has remained fairly steady with a slight decline over the same time period. Previously, FSRU costs experienced a noticeable increase from 2009 to 2010 as the number of floating terminals in the fleet jumped from four to ten; some of which were capital-intensive projects. In general, regasification equipment, storage tanks, send-out pipelines, vessel berthing, and the metering of new facilities comprise the costs of a new regasification terminal.

$274/tonne
Average costs of new onshore LNG import capacity in 2017

The weighted average unit cost of onshore regasification capacity that came online during 2017 was $274/tonne (based on a three-year moving average). This is slightly lower than the 2016 average ($307/tonne), as the Hitachi (Japan) and Swinoujscie (Poland) projects, each with relatively higher dollar per tonne unit costs, both began operations in 2016 (see Figure 6.11). Although some higher unit cost onshore projects began operations in 2017, such as Yuedong (China), other new onshore terminals that came online, including Dunkirk (France) and RGT2 (Pengerang) (Malaysia), had much lower unit costs. However, the general rise in onshore regasification costs since 2012 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. If all developing projects come online on time, CAPEX for under-construction onshore capacity is set to rise to $361/tonne in 2018, then fall to $269/tonne in 2019 with smaller terminals under development. However, several proposed projects that may soon reach construction milestones have higher CAPEX, which could ultimately bring these averages higher. Nonetheless, these figures vary significantly on a case-by-case basis, often depending on country-specific factors, including associated infrastructure development requirements.

In general, CAPEX for floating terminals can be lower than onshore projects, given that FSRUs typically require relatively limited infrastructure development to begin imports. On the other hand, OPEX for FSRUs can be higher than onshore terminals owing to the vessel charters associated with the projects.

CAPEX for FSRUs has remained fairly level over the last few years, declining slightly from a recent high of $158/tonne in 2014. Based on a three-year moving average, the weighted average unit cost of an FSRU in 2017 was $129/tonne. A rise in FSRU conversions, which can be brought into operations at a lower cost than new-build vessels, will be a factor in reducing average floating terminal CAPEX. However, this figure is slightly skewed due to limited reporting of CAPEX figures for recently completed floating terminals. Eight floating regasification terminals were under construction as of March 2018, in addition to two additional projects that have agreed to terms with an FSRU provider. Two of these projects have notably high CAPEX, particularly the Brazil and Russia (Kaliningrad) developments, indicating that average FSRU costs could be rising moving forward. Nonetheless, offshore terminals typically have less variance in CAPEX in comparison to regasification capacity developed onshore owing to more uniform designs in capacity and storage size in vessel-based developments.

6.9. Risks to Project Development

Regasification terminal developers must often confront multiple difficulties in completing proposed terminal plans, although they are perhaps not as daunting as those challenges facing prospective liquefaction plant developers. Regasification developers can mitigate some of these risks when choosing a development concept, based on the advantages and disadvantages of floating and onshore terminal approaches. However, both FSRUs and onshore developments are tasked with circumventing comparable risks in order to move forward. These include:

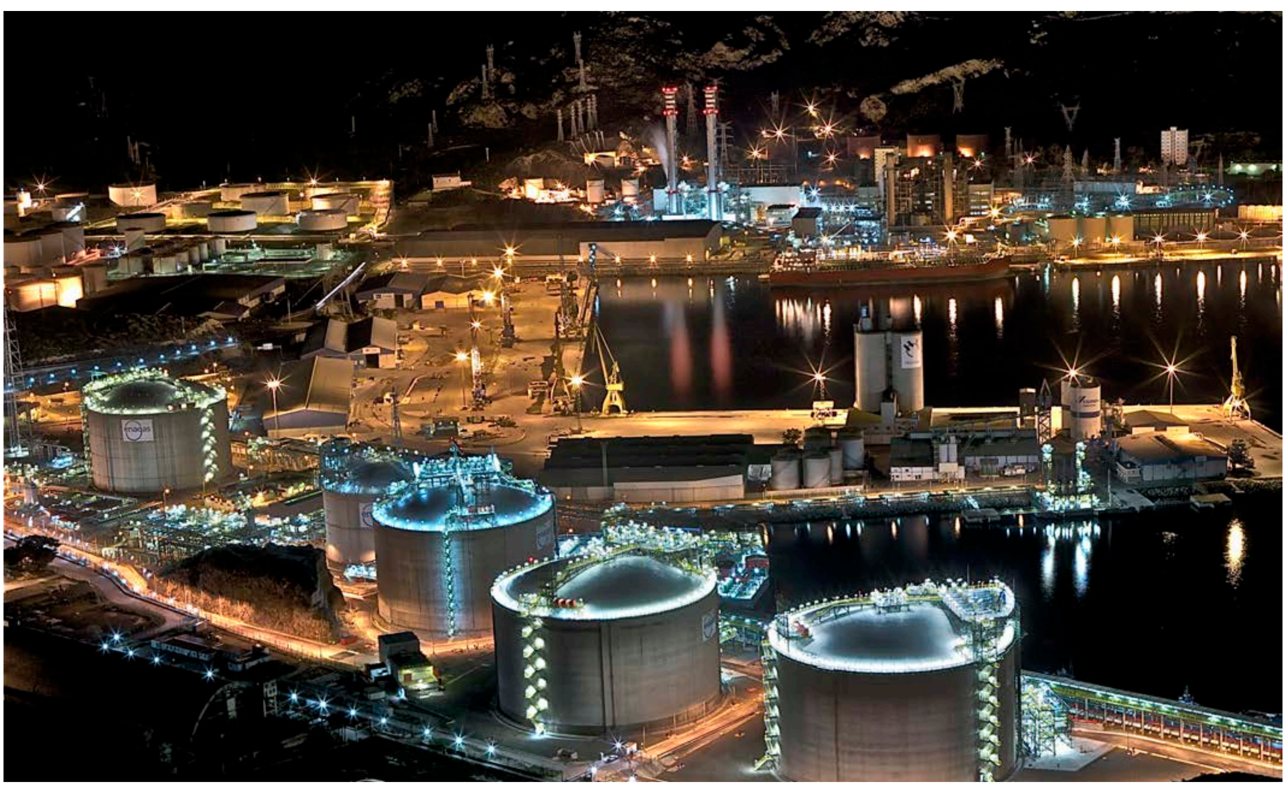
- **Project and equity financing**, which are required for terminal plans to advance. Bangladesh's Moheshkhali LNG (Petrobangla) FSRU project has faced multiple delays, largely due to financing challenges. The latest announcement indicated a mid-2018 target start date for start-up. The Puerto Rico Energy Power Authority (PREPA) filed for bankruptcy in mid-2017, slowing progress of the Aguirre GasPort FSRU project.
- **Permitting, approval, and fiscal regime.** New regasification terminals can face significant delays in countries with complicated government approval processes or lengthy permit authorization periods. South Africa's LNG terminal plans have been delayed by complications with its integrated resource plan. Chile's Penco Lirquen FSRU project has also faced delays due to an environmental permit being revoked in early 2017.
- **Challenging conditions in the surrounding environment** could lead to delays or cancellations of regasification projects. Puerto Rico's Aguirre GasPort FSRU has been put on hold indefinitely partially due to the effects of Hurricane Maria.
- **Reliability and liquidity of contractors and engineering firms** during the construction process. Financial and regulatory issues with contractors or construction companies can lead to project delays or even equity partners pulling out of the project all together.
- **Securing long-term regasification and offtake contracts** with terminal capacity holders and downstream consumers, particularly as the market shifts toward shorter-term contracting. Uruguay's FSRU project, the first for the country, faced significant uncertainty given that a supply deal between Uruguay and Argentina had not been reached. MOL chartered the vessel in Turkey for the short term and Argentina is not willing to commit to long-term offtake from the project. Therefore, the project considered stalled. For the development of new terminals, political support could be needed if long-term commitments are not secured.
- **Associated terminal and downstream infrastructure** including pipelines or power plant construction required to connect a terminal with end-users, which are often separate infrastructure projects that are not planned and executed by the terminal owners themselves. Ghana's West African Gas Limited (WAGL) Tema LNG project required significant downstream infrastructure development in order to move forward. The *Golar Tundra* was delivered in May 2016, but remained idle offshore for over a year. The WAGL Tema project was reported to have been replaced in September 2017 by a revised project proposal in Tema supplied by Gazprom, and the *Golar Tundra* FSRU sailed away shortly thereafter. The Kochi terminal in India continues to limit receiving capabilities due to the lack of completed pipeline connections to downstream users.

Looking Ahead

How will increased third-party access to regasification facilities affect terminal developments moving forward? As the global LNG market adds significant new supply in the near term, there will be potential for new customers in both existing and new markets. Given that many regasification terminals around the world operate at low regasification utilisation, current terminal operators may be incentivized to lease out capacity to willing customers in their domestic markets. This trend, which has already existed in established markets such as Europe, is picking up pace around the world, including in emerging market regions like Southeast Asia. National oil companies (NOCs) and single-entity terminal operators are becoming more open to allowing other domestic players access to their existing regasification capacity, in some cases due to government-mandated efforts to liberalise local gas markets. If this trend continues, perhaps less greenfield regasification capacity development will be required, in favour of expanding regasification utilisation at existing terminals via third-party access. For more information, please refer to Chapter 8: Pathway to Liquidity for LNG in the Energy Markets.

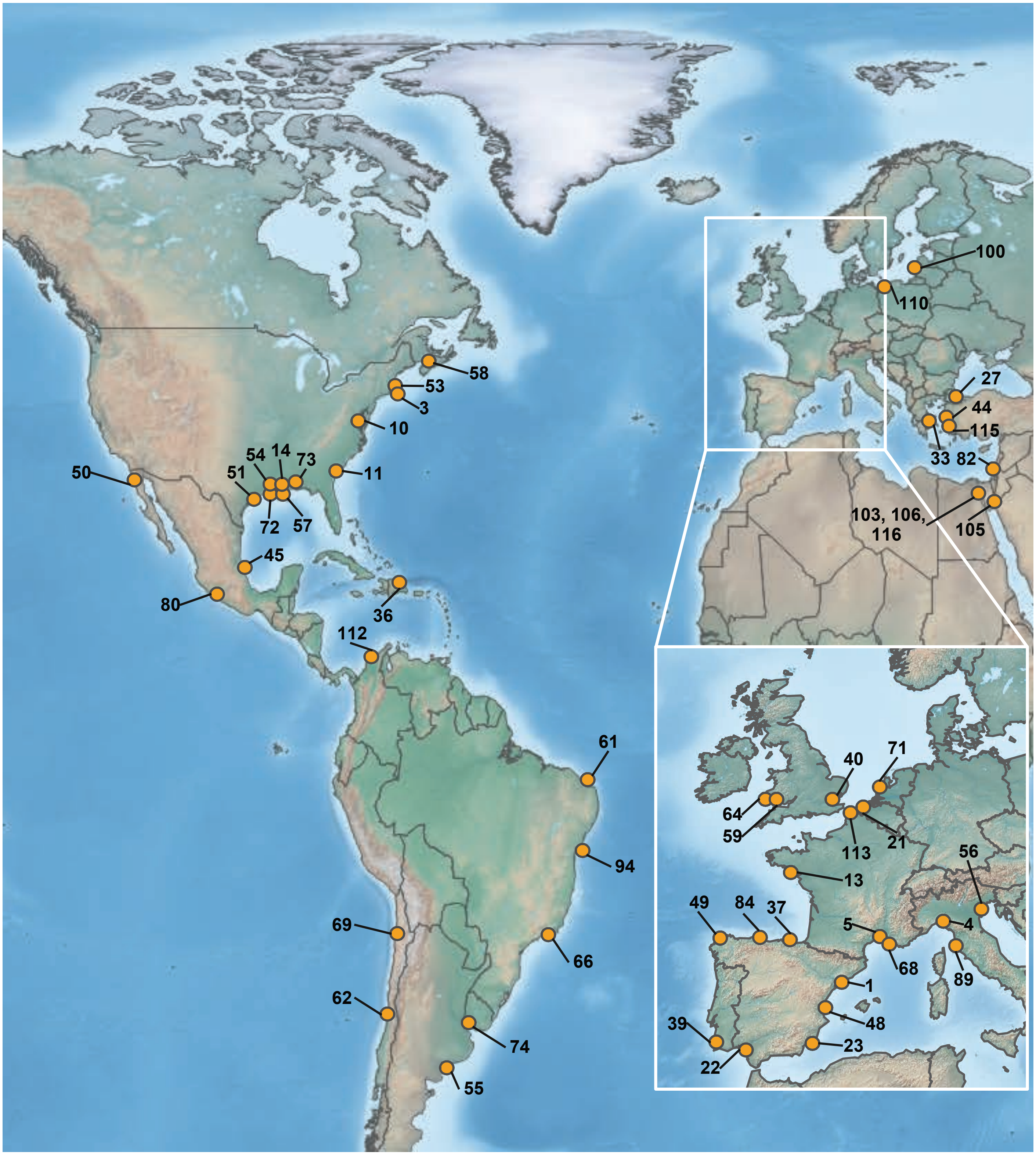
With the expectation of growing LNG supply and power demand, can emerging markets realise the potential of increasing gas utilisation? Lower LNG prices can create scenarios that favour fuel substitution in the power sector of new markets. Many emerging markets heavily utilise coal or fuel oil in their power sectors, and lower LNG prices allow for greater competition with other sources as a primary power generator. Jamaica, for example, began LNG imports in 2016 through a small-scale terminal as gas slowly began to displace oil in the power and industrial sectors, and Colombia's FSRU reached operations in the same year as gas entered the power sector to help stabilise seasonally varying hydropower. Power demand in general is increasing across many emerging markets, and LNG is set to play an important role in filling this growing gap. However, in many cases, significant infrastructure development, including constructing greenfield gas-fired power plants and associated pipelines, is required before these potential new markets can reach their full potential as an LNG importer.

Will existing markets continue to produce the bulk of near-term regasification capacity growth in the LNG market? Receiving terminal capacity growth in 2017 was entirely composed of additions in existing importing countries, as was the vast majority of capacity additions in 2016. This trend is in stark contrast to 2015, in which multiple new markets comprised a high portion of regasification capacity added that year. The expectation of growing LNG supply has created interest by new markets. Indeed, Bangladesh, Panama, the Philippines, Russia (Kaliningrad), and Bahrain all have their first regasification terminals under construction, with announced start dates by end-2019. However, a number of these terminals have experienced delays, and additional postponements are possible. Furthermore, existing markets, including China and India, have substantial amounts of regasification capacity both under construction and planned, suggesting that a significant proportion of added regasification capacity in the near term could continue to come from established LNG markets.

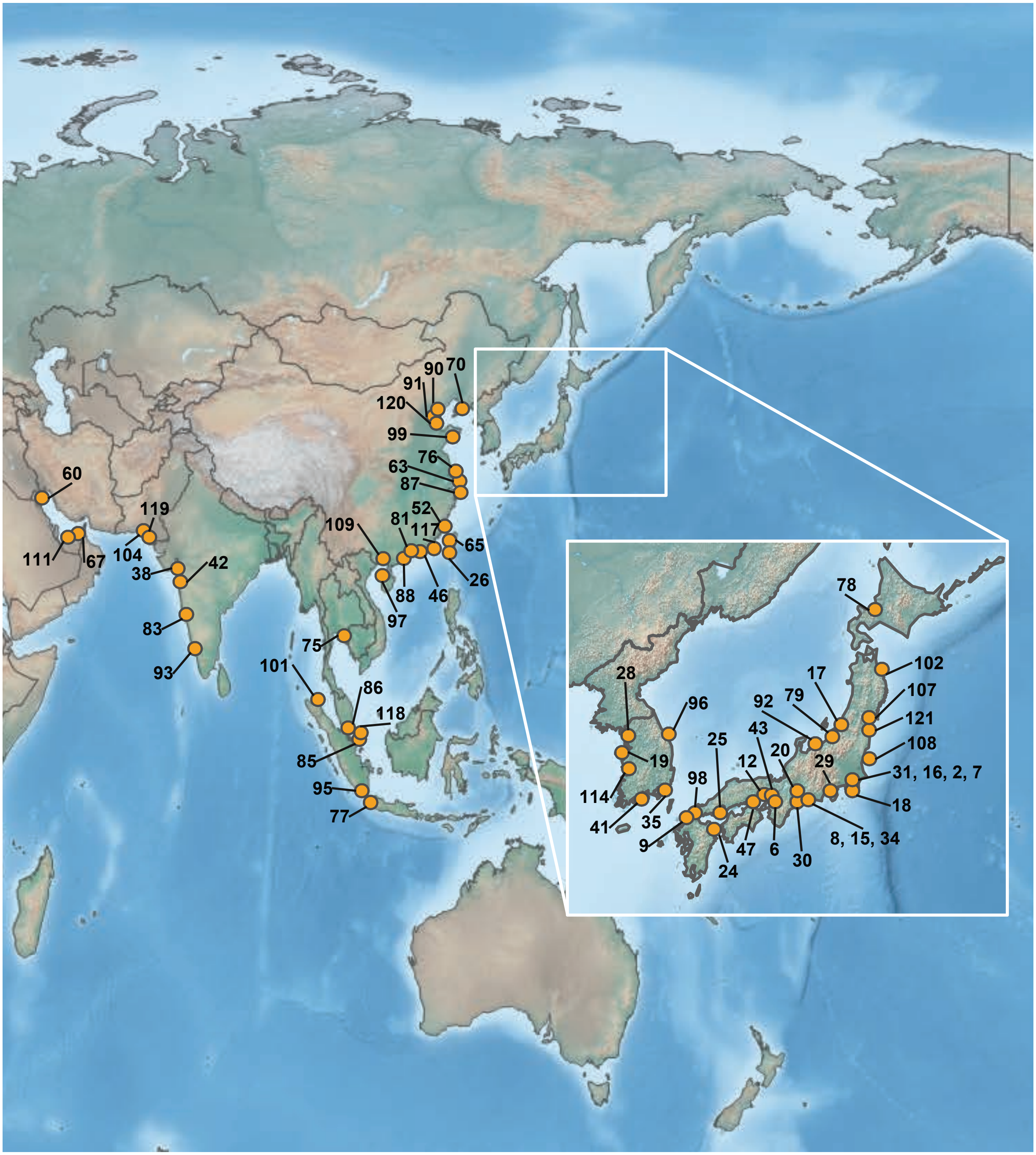


Cartagena – Courtesy of Enagas

Figure 6.12: Global LNG Receiving Terminal Locations



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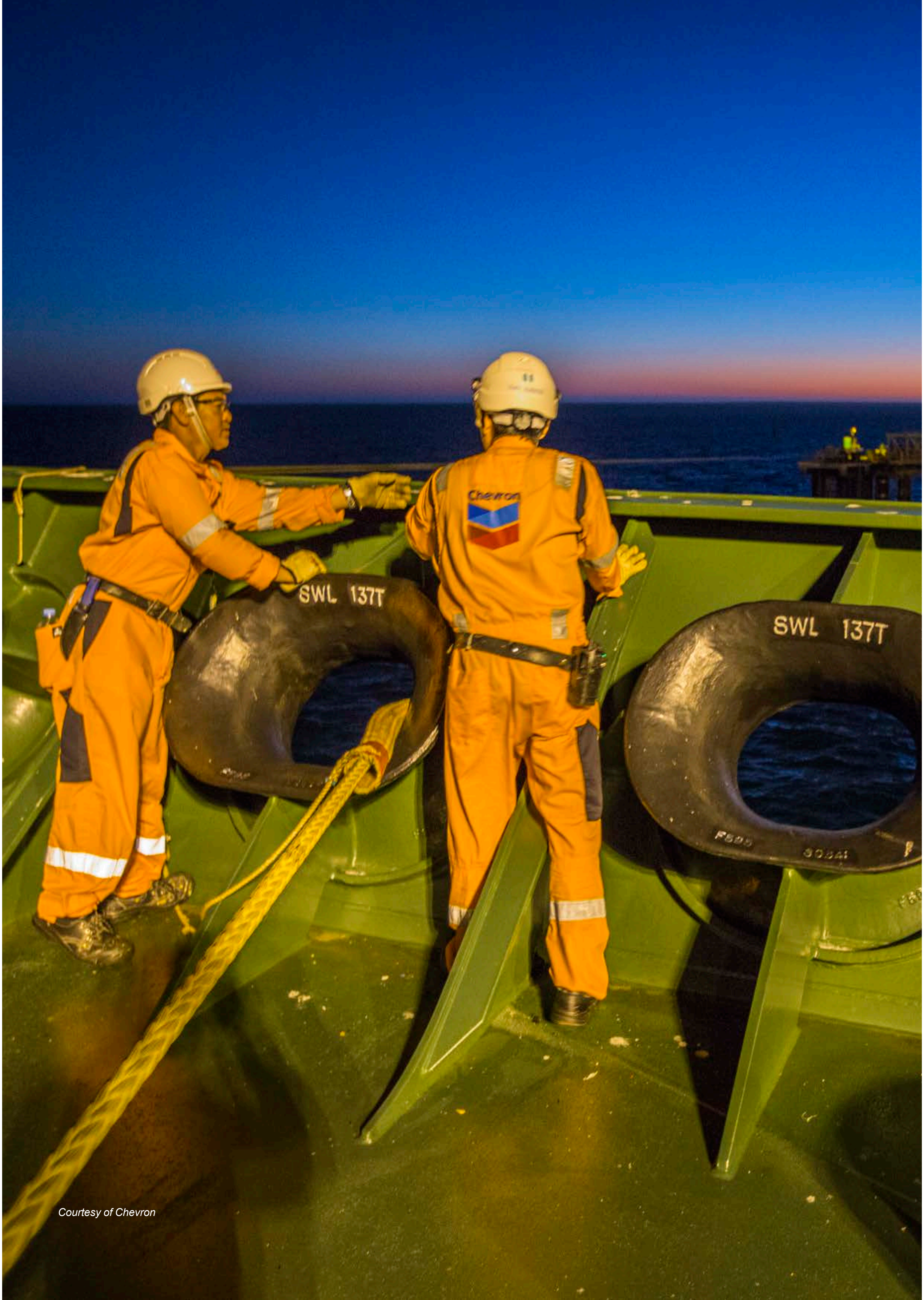


Courtesy of Chevron

7. FLNG Concepts, Facts, and Differentiators

Executive Summary – Scope of Work and Approach

The scope of the study group "FLNG concepts (LNG FPSO & FSRU), facts and differentiators" was to explore the floating LNG concept's evolution in the recent years, as to provide a view on the trending facts and driving differentiators for the potential use of this concept, in the LNG industry.

Floating LNG concepts are:

- LNG FSRUs: Floating storage and regasification units and
- LNG FPSOs: Floating liquefaction, storage and offloading units.

Commercial and technical aspects provide insights in facts and differentiators for the development of FLNG solutions and their particularities. Criteria are extracted, which make FLNG projects feasible, including success/non-success stories. Specific stand-alone study cases are compiled, but also cases with comparisons of onshore versus floating developments.

LNG Outlook and Trends

According to the current LNG demand forecasts from main analytical agencies, the market will not eliminate its surplus until 2022-23. However, FIDs on new LNG supply are required by the next decade to avoid a tight market in the 2020s, given the typical LNG onshore projects implementation delivery times.

LNG sales contracts are moving towards shorter terms, changing the definition of a long-term contract. Suppliers will need to be flexible in contract terms including length, destination and indexes. This increased flexibility applies to both the producing and receiving facilities for LNG and implicates an impact to development of FLNG concepts.

Niches in the LNG market will continue to play an important role in demand growth: FLNG concepts, and small and mid-scale LNG are added-value solutions for the long run or as a bridge solution awaiting development of larger production/consumption.

LNG FSRUs

FSRUs are proven, reliable, competitive, and flexible solutions that can offer significant advantages over onshore LNG import facilities. The main potential benefits of FSRUs are cost optimization and reduced time-to-market as well as reduction in regulatory and permitting complexity.

FSRUs offer benefits in terms of flexibility via the ability to relocate the facility and can resume production immediately at another location. In addition, FSRUs can provide flexible business models for projects promoters, such as the ability for a time charter instead of upfront CAPEX investment. Modularisation and/or combinations of FSRUs with FSUs can provide fit-for-purpose solutions that enable to reach markets in a required time schedule.

FSRUs should be close to the coast, inside a port or a protected area. With respect to near shore versus open sea FSRUs, near shore has many advantages when implemented in a protected and developed port. The open sea solutions, likely to be exposed to harsh metocean conditions, have not been as widely applied so far.

There are issues to address comparing a new built and a converted FSRU. CAPEX and OPEX considerations are important but also flexibility has an impact on the decision-making process. Conversions may take less time and have benefits from a CAPEX perspective, but new builts can be developed with more design flexibility and longer life span. Differentiators between the two options are project duration, regulations, EPC companies, shipyards, owners, technical challenges, and business opportunities.

FSRU Toscana (Italy)

LNG FPSOs

LNG FPSOs have been discussed for decades. Facts supporting the installation of an LNG liquefaction facility on a floating structure are non-availability or difficult access to the waterfront, long subsea pipeline distances, and navigational limitations to shore, or the production scale. These factors are triggers for an LNG FPSO project.

LNG FPSOs can be relocated but with significant effort, and most likely require major modifications to adjust to the new gas field composition and conditions. Like FSRUs, LNG FPSOs can provide a fast track schedule e.g., for small/mid-size fields or if a bridge solution is required prior to a larger scale production.

An LNG FPSO facility can be constructed and commissioned in a controlled shipyard environment with higher productivity and often lower labour rates. It therefore can provide savings versus the construction of a conventional stick-built onshore liquefaction facility. The difference between shipyard construction and commissioning is the fact that it provides higher delivery schedule and cost confidence than onshore construction. Like FSRUs, commercial tolling or lease arrangements can be applied to near shore small- to mid-scale LNG FPSOs avoiding the initial capital outlay.

The technical concepts and solutions for open sea and near shore LNG FPSOs are different. Open sea LNG FPSOs are preferably utilised to avoid long pipelines, but are without doubt more exposed to metocean conditions, and thus require technically sophisticated mooring and berthing solutions.

FSRUs and LNG FPSOs Conversions Versus New Builts

Both for LNG FSRUs and LNG FPSOs, the discussion on facts and differentiators between conversion and new built alternatives is one of the first and most important steps, which influences the choice. A good understanding of the facts and differentiators of the alternatives is a prerequisite to take the right decision. The assessment shall be based on cost information, schedule requirements, project execution insights, and technical compromises.

Conclusions

Over the last decades the LNG industry has built up experience with floating LNG concepts generating many success stories but also examples with less positive feedback. There is no such thing as a typical floating LNG project. Many projects are basically prototypes and one-off developments.

The main drivers/challenges for developing these projects are location, countries' energy policies, regulations, environmental impacts, business model flexibility, financing, overall LNG market trends maybe more than the technological aspects, as LNG vaporisation processes for FSRUs and liquefaction processes for LNG FPSOs are well-known and applied throughout the LNG industry. As for any LNG development, the potential optimization in terms of costs and implementation schedule are part of the key enablers for the FLNG developments.

The regasification floating solutions (FSRU) have experienced a high momentum in the recent years because of the flexibility they provide for having shorter time-to-market solutions especially for newcomers to the LNG or for seasonal demand issues. On the other hand, the LNG FPSOs have somehow experienced a lesser success in the last years, following the trend in the LNG industry, in which only a few liquefaction FIDs have been taken in a short-term scenario with depressed gas prices and oversupply.

FSRUs keep on growing fast. With recovered demand growth and higher price signals LNG FPSOs can gain momentum for developing small- to mid-size stranded gas resources.

LNG PFSO Petronas Satu (Malaysia)

8. Pathway to Liquidity for LNG in the Energy Markets

Executive Summary

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

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

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

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

LNG Hub Formation

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

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

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

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

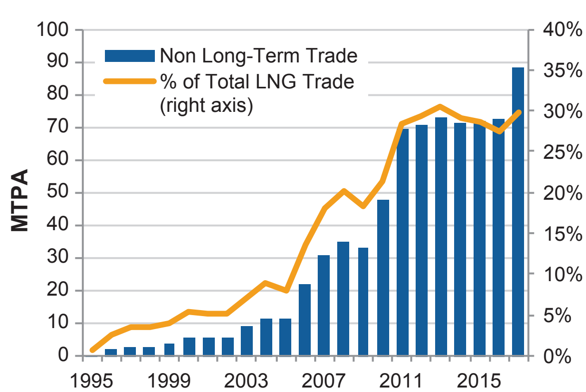
Capital Costs

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

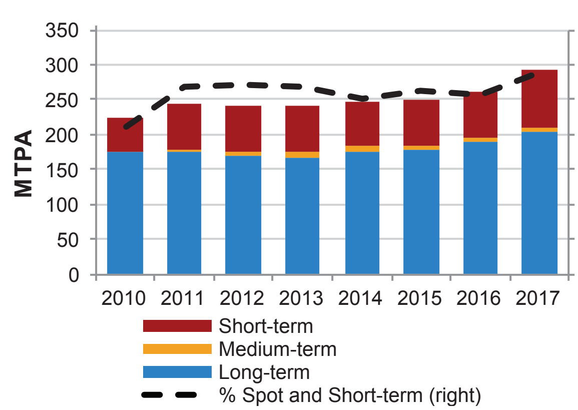
While none of these represents a 'silver bullet' which will radically reduce costs overnight, there are reasonable expectations that some of these might work.

Shipping

The current LNG shipping market is driven by technical, logistical, commercial, regulatory, financial and cultural factors which can either constrain or reinforce its level of liquidity. When analyzing the liquidity of the shipping market, we look



Sources: IHS Markit, IGU



at the transactions which are made, the period of the same, available fleet, the amount of production that enters into the market, freight level and other relevant factors. The growth in liquidity began in 2013 as a wave of LNG carriers was delivered by the shipyards, many without term engagements, adding length to the shipping market.

Receiving Terminals (Including Small-Scale)
Receiving terminals have an impact on liquidity due to various factors, such as, capabilities, services offered and commercial issues. For this reason, to obtain a global, flexible and liquid market, LNG terminals have a key role and operators should constantly optimize utilization of their facilities and invest in improvements to allow large and small scale activities to coexist at the terminals. These enhancements will help create liquidity to stimulate the creation of a global market that will ensure the security of supply and a coherent LNG price.

Market/Supply
The LNG market has dramatically changed over the past half-decade. Especially, on the supply side, a surge in natural gas production in the United States has eliminated the need for imports and promoted flexible LNG exports. At the same time, new LNG projects from Australia have added significant supply to the balance. This large growth in supply and increasing flexibility is having an impact on volume of LNG in the spot market. In addition, from the perspective of the demand side, the market has balanced via growing consumption from traditional consumers. Also new countries are starting to import LNG as volume has grown and pure traders enter this space. The market has clearly increased the number of buyers and sellers. To keep the momentum towards the market liquidity, the number of participants on both sides needs to keep growing to eliminate the distorting effects of market concentration.

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

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

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

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

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

9. Flexible LNG Facilities

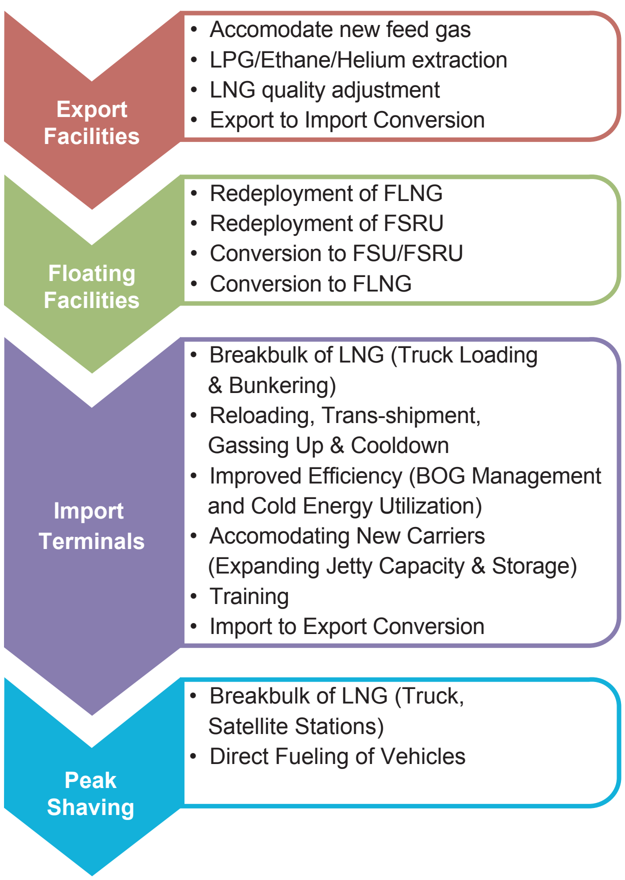
The LNG industry has passed its 50th year and now many facilities have aged. Meanwhile, the nature of LNG market has changed significantly. These changes have led to the need for terminals to modernize and become more flexible by adding new functionality beyond their traditional role.

Flexible LNG facilities are those facilities to which functions and activities are added or changed to allow for different uses or operations. In many cases, the original design purpose for these LNG facilities is retained but, in other cases, changes may alter the design function.

Traditionally, the LNG value chain has been rigid, with building blocks which are well-defined with limited functionalities:

- **LNG Export Facilities** – Where natural gas is treated, cooled and liquefied to be shipped to LNG Markets
- **Floating Facilities**– LNG carriers which transport LNG to suppliers on long-term contracts
- **LNG Import Terminals** – Where LNG is received, stored and regasified to be provided to customers
- **Peak Shaving Facilities** – Where natural gas is cooled, liquefied and stored, ready to be regasified to meet periods of peak demand

Figure 9.1: Overview of Archetypal Functionalities Added to LNG Facilities



Changes are now being seen in the value chain and in each of these building blocks with the addition of new functionalities as outlined in Figure 1. In the first link of the LNG chain, **LNG Export Facilities** are not only adapting to changing feed gas compositions due to aging or new gas fields but, in many cases, they are also adding additional facilities to extract and sell new products such as ethane, LPGs, and helium.

The role of **Floating Facilities** is also changing with the evolution of the industry. Whilst the floating element in the value chain is traditionally the LNG carrier servicing long-term supply contracts, enhanced functionality can be found in the conversion of LNG carriers to floating facilities such as Floating Storage, Regasification (FSRU) and Liquefaction (FLNG). The potential for floating facilities to be redeployed elsewhere brings additional unique flexibility to this element of the LNG value chain, whether they constitute a conversion or new build.

Flexibility is also being introduced in **LNG Import Terminals**, which have the potential to serve as a LNG Hub, where LNG is received in bulk volumes from an LNG carrier and is then distributed by many different channels, parallel to the typical send-out gas pipeline. For example, in smaller quantities as a liquid distributed in LNG trucks or small-scale LNG carriers to enter the LNG for transport market. The addition of other services such as ship-to-ship trans-shipment, the reloading of small scale LNG carriers to feed other LNG terminals, and LNG Carrier gassing-up and cooling-down can also increase the terminal operator's commercial palette, as shown in Figure 2.

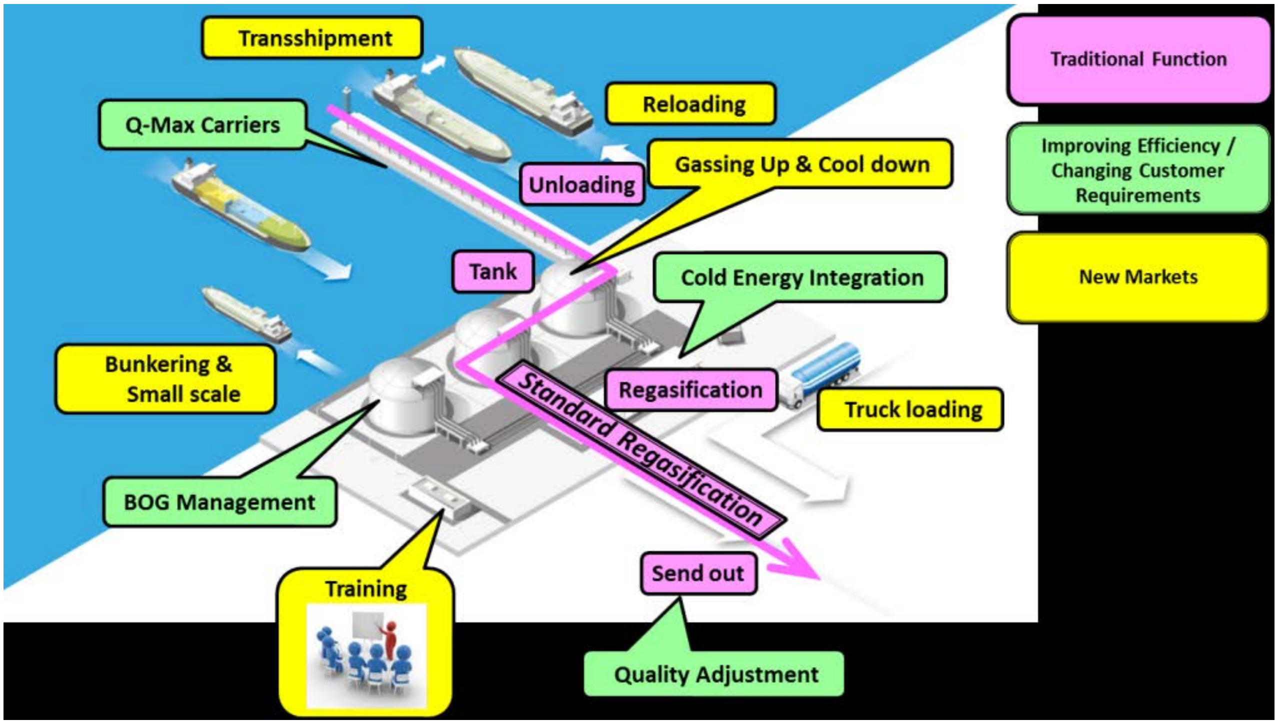
Peak Shaving Facilities have also been subject to the profound changes in the LNG value chain, particularly in North America. The most common addition to peak shaving facilities is truck-loading facilities to allow the terminals to access the high-value LNG for transport market.

Finally, the most substantial and visible change in functionality is the inversion of functionality in a facility. This can be seen in the well documented Import-to-Export LNG terminal conversions in the USA but also, in contrast, where a liquefaction plant has been converted to an import terminal to meet rising local demand such as the Arun LNG Terminal in Indonesia.

The addition of these new functionalities can be attributed to a range of drivers which can be broadly classified as either business-driven, where change is driven by the terminal in a bid to enter a new market segment or adapt to market changes, or stakeholder-driven, where the terminal needs to adapt to the changing demands of suppliers, regulatory bodies and society.

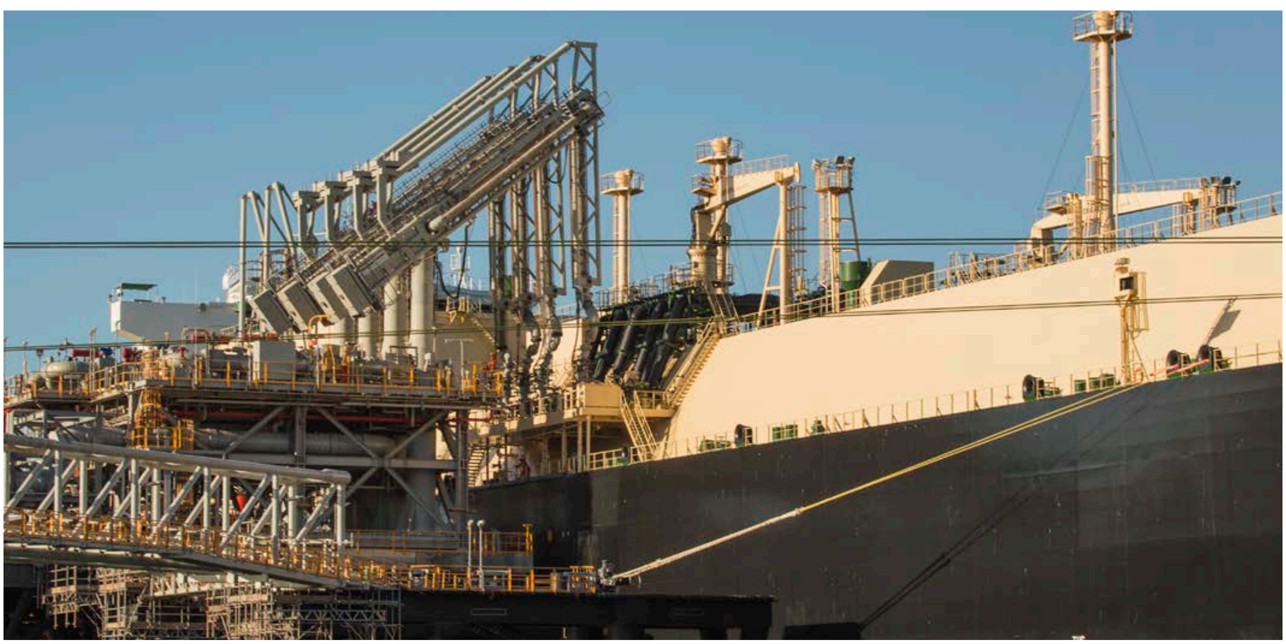
In order to meet the Paris Climate Change targets, the global energy mix will see significant decarbonization. As part of this transition, the role of LNG is forecast to grow not only in providing gas to power but also in new markets such as fuel for the haulage and maritime sectors. This will lead to the growth of LNG hubs where the core business is LNG breakbulk with redistribution to smaller satellite terminals, re-export of LNG, and providing LNG for transport sector.

Figure 9.2: Flexibility in LNG Import Terminals



In addition, as society moves to a carbon-neutral energy mix, new functionalities could be envisaged. One such new functionality is associated with the increase in biogas production. This presents an opportunity for facilities in biogas-producing countries to become involved in the development of the bio-LNG market. This may involve the addition of bio-LNG treatment and small-scale liquefaction units. For instance, in France, which has set the target that by 2030 10% of all gas will come from renewable sources, facilities will be needed to store and transport this gas.

In the more than 50 years of the LNG business, there have been many changes and evolutions. As industry continues to grow and develop, changing market demands coupled with the acceleration of the energy transition will lead to significant opportunities for those terminals able to adapt to the new reality. Embracing the functionalities outlined in this report will be key for all elements of the LNG value chain if they are to secure their part in the growing role of LNG in the Energy Transition.



Courtesy of Chevron

10. The LNG Industry in Years Ahead

How Will LNG Markets Balance in 2018?

For some time now, the global LNG market has anticipated a supply build-up that would grow faster than it could be absorbed. However, the expected "excess" LNG looking for a home in northwest Europe has not yet arrived. This was the result of higher Asian demand, particularly in the winter due to environmentally-driven increases in Chinese demand and high levels of nuclear power plant maintenance in South Korea. This higher seasonal demand indicates that the global market can remain balanced – or even tight – in the winters, as new LNG export capacity ramps up.

Asian LNG prices in winter 2017–18 spiked to over $11/MMBtu, more than double summer levels, and the highest prices in three years. The differential between northwest European and Asian spot prices is a key indicator of market balance. In the past three years, the differential has collapsed in the summer down to netback parity for flexible LNG suppliers – a sign of a well-supplied market. In the northern hemisphere winters, this differential has increased due to the cold-weather demand of northeast Asia, but typically just above the cost of reloading LNG from Europe.

In North America, the price of oil appears to be the single biggest influence on domestic associated gas production. U.S. LNG exports will continue to impact global gas markets as production ramps up. As U.S. oil production grows more resilient at relatively low sales price, gas production growth and LNG exports will remain economic. Tracking this signpost will be critical to North American gas price over the next decade.

Will LNG Contracting and Liquefaction FIDs Take Shape This Year?

Investment decisions on new LNG supply have come to a near standstill over the last two years. In 2017, only one large-scale LNG project reached FID – the 3.4 MTPA Coral South FLNG in Mozambique – marking the lowest volume of sanctioned LNG in nearly twenty years. This follows the trend established in 2016, when only two projects reached FID for a combined sanctioned capacity of 6.3 MTPA. This contrasts with the high level of FIDs in 2011–15, when annual sanctioned capacity exceeded 20 MTPA. The slowdown in investments is partly a reflection of the wider trend of cutting back capital expenditure across the oil and gas industry during the commodity downturn, but can also be attributed to the lack of contracting activity from buyers hesitant to sign long-term deals in the face of growing near-term LNG supply. Without long-term contracts, new liquefaction projects will find it challenging to proceed.

The total volume and number of LNG contracts signed has declined consistently for the past three years. In 2017, only one firm long-term contract was signed that was tied specifically to a proposed project working toward FID (Edison's SPA at Calcasieu Pass LNG), as the majority of deals completed were portfolio contracts (67% of all firm deals signed). The lower total volume of contracts is not only a result of fewer contracts being signed, but is also tied to the trend of smaller volume contracts – the average size of contracts signed has dropped, which means that marketing timelines extend as they seek to fill the entire capacity.

It is in the interest of both buyers and sellers that some liquefaction investment takes place in 2018, as a continuation of the investment impasse raises the prospect of a sharp cyclical turn to shortage in the first half of the 2020s. But obstacles remain and the way forward is unclear. A third year of low investment activity following 2016 and 2017 would highlight a disconnect between forecasts of strong LNG growth over the next 10 to 15 years and the reality of a slowdown of investment activity. This year will be critical in defining the trajectory of the industry in the medium-term and beyond.

Could Demand in Mature Asian Markets Surprise to the Upside, Again?

Growth in LNG demand in 2017 was overwhelmingly concentrated in Asia. If these markets have another surprisingly strong year of LNG demand growth, it could prevent the surge in Northwest European LNG imports currently forecasted by some market observers. However, several factors contributed to the strong growth in 2017, which are unlikely to be replicated at the same scale in 2018. China has been the most significant spot LNG purchaser since September, as the national government seeks to aggressively curb air pollution. However, gas demand growth is not expected to stay at the target-driven accelerated levels of 2017.

The publication of South Korea's 8th Basic Plan for Long-Term Electricity Supply and Demand in December 2017 outlined major changes in the country's long-term energy policy, with no new nuclear or coal plants beyond what is already under construction. However, nuclear uncertainty has also crept into the short-term outlook. Extended nuclear maintenance outages in South Korea contributed to higher LNG demand than expected in 2017. Average annual nuclear availability fell below 70% in 2017, far lower than typical levels of 80–86% over the past few years. Extended nuclear maintenance schedules look likely to continue into 2018, offsetting the decline in LNG-fired power generation expected following the new coal and nuclear capacity that has come online over the previous 18 months.

LNG imports of the world's biggest consumer, Japan, are heavily dependent on the pace and extent of nuclear restarts. Another court injunction in late 2017 highlights the ongoing uncertainty. On 13 December 2017, the Hiroshima High Court revoked a lower court decision and ordered the suspension of Shikoku Electric's Ikata reactor #3, questioning safety screening under stricter post-Fukushima regulations. The reactor became the fifth to resume operations when it restarted in August 2016 and had been temporarily shut for routine maintenance in October 2017. Now it will be unable to restart until at least the end of September 2018, the duration of the suspension order. The impact of this particular plant on LNG imports is expected to be small, but it does highlight the ongoing uncertainty and court challenges affecting the restart of Japan's nuclear fleet, and the subsequent impact on LNG needs. At least four reactors are due to restart in 2018 – Kyushu Electric's Genkai #3 and #4 and Kansai Electric's Ohi #3 and #4. While these restarts were pushed back by two months for further checks, they have been approved and two of the reactors (Genkai #3 and Ohi #3) were restarted in April 2018, with the other two to follow in May.

What Strategies Will Be Used to Address Emerging Markets?

With a significant amount of new supply available, many have suggested the potential for emerging and new markets to adopt LNG imports. While there are a great number of countries around the world that have the potential to begin importing LNG, few will be easy to access without significant investment. There are a host of challenges to the development of LNG imports in new countries, but they are not so burdensome as to halt new development. An international oil company (IOC) or aggregator with extensive LNG experience can be a catalyst to development, though this will still require host government leadership.

Several companies have also proposed the concept of the "milk-run" or "hub-and-spoke" model wherein a large LNG vessel would deliver LNG in smaller parcels to several demand points, either directly into the port or by discharging to smaller shuttle vessels. This model of supplying LNG to multiple offtakers is an option in markets with small, disparate demand centres, like Indonesia, the Caribbean, or West Africa. Such deliveries could be through a hub located within the region, or through imports from an LNG supply point. Jamaica's small-scale demand has recently been met by a creative solution that could be the first step in a potential hub-and-spoke strategy; it conducts ship-to-ship transfers between the large-scale *Golar Arctic* and small-scale *Coral Anthelia* to bring LNG imports to onshore regasification. Another six Caribbean countries have proposed building regasification terminals, mostly on a small scale; Jamaica's model – plus the addition of re-exports in the Dominican Republic in 2017 – could help unlock the region as a bigger source of LNG demand. However, given the small size of their economies, most emerging markets, even if combined, will still be relatively small.

How Will New Floating Liquefaction Projects Perform?

This year will be newsworthy for new FLNG projects. The first FLNG unit in the world, Malaysia's PFLNG Satu, sent out its first cargo in March 2017. Prelude FLNG, which is the largest floating liquefaction project under construction at a capacity of 3.6 MTPA, is expected to start up by the end of the year. The vessel arrived on site in the Browse Basin in June 2017, and Shell expects it to be online in Q3 2018. Cameroon's Kribi FLNG is the next floating project expected online, with the first cargo targeted for Q2 2018. Unlike PFLNG Satu, which is a purpose-built facility, Kribi FLNG will utilize a converted LNG carrier from Golar LNG's fleet. The market has good reason to closely watch the startup of the Kribi FLNG conversion project, since there are several other projects that are planning (or considering) to use the same approach. In Equatorial Guinea, Fortuna FLNG has hit most major milestones – including fully contracting offtake to Gunvor – and plans to reach FID in 2018. Companies in several other locations around the world, including the Mauritania/Senegal border and Iran, have also suggested using converted FLNG units, touting them as a faster, cheaper way to commercialize newly-opened gas reserves. If Kribi FLNG starts up smoothly, it will lend credence to the converted FLNG approach, given the availability of laid-up carriers.

Will the Pace of Demand for LNG Bunker Fuel Accelerate?

While LNG has been used successfully as a marine fuel for more than a decade, the discussion of the use of LNG in the bunkering sector has accelerated over the past several years. The International Maritime Organization's (IMO) 0.5% 2020 sulphur cap on global[1] marine fuels – a considerable change from the 3.5% global emissions limit in place now – is leading the global maritime industry to more actively consider LNG as a fuel. A major milestone was reached in November 2017 when nine large containerships were ordered that will be fuelled by LNG. The size of the vessels and the associated fuel consumption is particularly notable, as they will be the first vessels to have a membrane-type fuel tank, with a capacity of 18,600 cm. This scale, as well as the simultaneously signed deal for LNG supply, adds confidence that this new LNG demand sector is progressing.

How quickly that future unfolds remains a key question. The first vessel is currently scheduled to be delivered in 2020, with the other eight to follow within a year; the estimated LNG consumption of the nine vessels works out to around 0.45 MTPA combined. Lack of infrastructure is frequently cited as an impediment to the adoption of LNG as a bunker fuel, but this deal demonstrates that it need not be. The fuel storage capacity of the nine ships was designed to cover a roundtrip between Asia and Europe.

The development of bunkering infrastructure is also poised to accelerate. Spain completed the first pipe-to-ship LNG bunkering operation in early 2017, and other terminals throughout Europe have been actively developing bunkering services, particularly to support LNG use in small-scale vessels. Singapore – one of the world's most established conventional bunkering ports already – launched its first trucking facility in 2017 (enabling both truck-to-ship bunkering and LNG trucking). In addition, four Japanese companies announced in January 2018 that they are evaluating an LNG bunkering business in Japan. Further, the development of LNG bunkering as a new source of demand could be attractive to other LNG suppliers, as building new LNG bunker infrastructure in familiar ports might prove more attractive than developing an entire downstream market in a relatively small emerging market where the entire gas industry needs development to ensure offtake.

Will the Recovery in the LNG Shipping Market Be Sustained?

The spot shipping market had its best year in 2017 in terms of number of bookings. Also, towards the end of the year spot charter rates increased to levels not seen in over three years. The increase in spot shipping demand has allowed ship owners to once again impose a ballast bonus, helping them recover repositioning costs such as fuel, hire, and canal fees. This is partly due to a seasonal uplift in the spot shipping market stemming from strong winter demand in Asia. Furthermore, new liquefaction capacity from Australia, Russia, and the United States has helped absorb a lot of the spare shipping capacity that had been putting downward pressure on spot charter rates. Over the next three years an additional 93 MTPA of new liquefaction capacity will come online, yet the shipping

[1] The cap is already in place in parts of North America and Europe.

orderbook has stagnated during the past two years. While over 100 ships on order are nearing delivery in the next few years, most of them are already dedicated to projects, leaving few shipping options for traders. The LNG market continues to have shipping inefficiency, as illustrated by laden tankers passing each other as they cross the Suez Canal. If this continues along with the scrapping of older tonnage, the market could grow tighter.

The low-cost tanker market of the past three years has helped commoditize the LNG market by allowing trading houses to participate more easily in LNG trade. Not having to take a long-term position on a vessel reduces the barriers of entry into the LNG market. The recent recovery in shipping rates is partly owing to these participants who use the spot tanker market for their shipping needs. However, a few of these trading houses are starting to take on vessels on medium-term charters, which could be an indicator of a tightening market.

What New Markets Will Begin Imports in 2018?

In 2017, Malta was the only new LNG import market, although small-scale at only 0.4 MTPA of regasification capacity. However, looking ahead, regasification terminals are under construction or under development in six new markets, four of which expect to begin imports in 2018: Bangladesh, Panama, the Philippines, and Russia (Kaliningrad). From a size perspective, Bangladesh is the most promising of the four, as the country has a sizeable domestic gas market already. Recent declines in local production have supported the case for LNG imports. Although low domestic prices delayed progress on imports for several years, the completion of a long-discussed import contract with Qatar in September 2017 is promising for the imminent start of imports. Bangladesh's first FSRU – the 3.8 MTPA Moheshkhali LNG (Petrobangla) – expects to come online in mid-2018, while an additional six terminals are being actively proposed. A limiting factor could be the expansion of coal-fired power, that is also under consideration.

Panama has turned to LNG to fuel gas-to-power projects. In September 2015, AES won the tender to supply Panamanian state-owned ETESA with power under a 10-year agreement, which it plans to fuel by building an LNG import terminal near the Panama Canal. An onshore terminal is under construction and expected to be complete by 2019, but in the meantime, a temporary FSRU (with a capacity of 1.5 MTPA) will allow imports this year.

While the Philippines has a relatively small gas market hindered by infrastructure, the country has shown signs of strong demand potential as it industrializes. LNG will primarily be consumed in the power sector, although coal continues to cap the potential of LNG demand growth. Several regasification terminals have been proposed, including the under-construction Pagbilao LNG hub, which is expected to begin imports in 2018.

The smallest new market expected to begin LNG imports in 2018 is Kaliningrad, a Russian exclave on the Baltic Sea. The market is currently supplied by pipeline from mainland Russia via Belarus and Lithuania. LNG imports have been proposed for supply diversity rather than full displacement of pipeline gas, given that the FSRU capacity is only 1.5 MTPA. The commissioning of the terminal's FSRU was delayed from last year by a boiler issue on the vessel, but imports are expected to begin in late 2018.

Will the Global LNG Market Move More Toward Commoditization or Consolidation?

As LNG buyers and sellers face growing LNG supply, increasingly uncertain demand in traditional markets, and new LNG technologies and project models, the traditional LNG market model is poised to evolve. There are two main potential pathways:

- A "Commoditization" model, which involves a shift toward shorter-term trading, growth in liquidity, and the entry of multiple new players;
- A "Consolidation" model, wherein LNG trade is largely in the control of "super-aggregators" – large companies with extensive global portfolios that are best placed to match multi-faceted producer and consumer needs.

Signposts toward the development of both models have occurred over the past few years. In support of consolidation, several major acquisitions and partnerships have marked a trend toward increased aggregator positions: TOTAL announced that it would acquire much of ENGIE's LNG business in November 2017, Shell has acquired BG Group, and the Ocean LNG partnership was formed between ExxonMobil and Qatar Petroleum in 2016. On the buyer side, the formation of JERA, a combination of TEPCO and Chubu Electric in 2015, sparked a trend of other Asian and European buyer partnerships. In support of commoditization, nascent LNG price markers in Asia – like Singapore's Sling index and Platt's JKM – have garnered much attention in the last few years and their use in the spot market is spreading, though long-term contract signings with these markers are still extremely limited. Traders have also begun to account for a much larger share of LNG trading and contracting activity; 24% of the contracts signed in 2017 involved a trader company, compared to just 1% in 2012. With both models appearing to gain traction, the question is whether one will start to overtake the other, or if the market can support a hybrid consolidation-commoditization structure.

Courtesy of Chevron

11. References Used in the 2018 Edition

11.1. Data Collection

Data in the 2017 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 Markit, company reports and announcements. This report should be read in conjunction with the 2015 and 2016 World LNG Reports, available on the IGU website at www.igu.org. The data and associated comments have been reviewed and verified by IGU.

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- Toho Gas, Japan: Taro Yahiro

11.2. Definitions

Brownfield Liquefaction Project: A land-based LNG project at a site with existing LNG infrastructure, such as: jetties, storage tanks, liquefaction facilities or 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.

Home Market: The country in which a company is based.

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 60,000 cm are considered part of the global fleet discussed in the "LNG Carriers" chapter (Chapter 5). Vessels with a capacity of under 60,000 cm are considered small-scale LNG carriers.

Long-term and Spot Charter Rates: Long-term charter rates refer to anything chartered under a contract of five years or above. Spot charter rates refer to anything chartered under a contract of six months or less.

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.

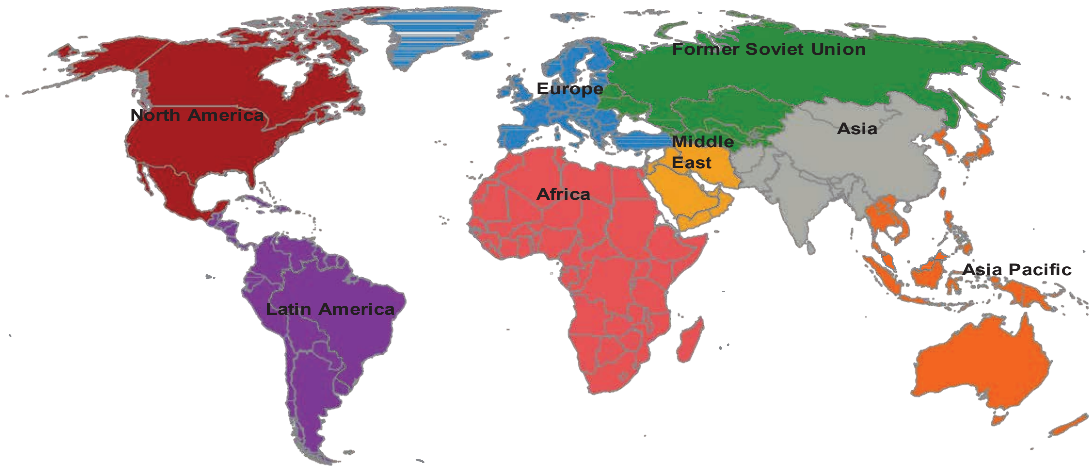
Short-term, Medium-term and Long-term Trade:

- 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.

11.3. Regions and Basins

The IGU regions referred to throughout the report are defined as per the colour coded areas in the map on the next page. The report also refers to three basins: Atlantic, Pacific and Middle East. The Atlantic Basin encompasses all countries that border the Atlantic Ocean or Mediterranean Sea, while the Pacific Basin refers to all countries bordering the Pacific and Indian Oceans. 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.



11.4. Acronyms

BOG = Boil-Off Gas
CAPEX = Capital Expenditures
CBM = Coalbed methane
DES = Delivered Ex-Ship
DFDE = Dual-Fuel Diesel Electric
EPC = Engineering, Procurement and Construction
FEED = Front-End Engineering and Design
FERC = Federal Energy Regulatory Commission
FID = Final Investment Decision
FOB = Free On Board
FLNG = Floating Liquefaction
FSRU = Floating Storage and Regasification Unit
FSU = Former Soviet Union
HFO = Heavy Fuel Oil
HOA = Heads of Agreement
IOC = International Oil Company
JKT = Japan, South Korea, and Taiwan
ME-GI = M-type, Electronically Controlled, Gas Injection
MDO = Marine Diesel Oil
MOU = Memorandum of Understanding
NBP = National Balancing Point
NOC = National Oil Company
NOX = Nitrogen Oxides
NSR = North Sea Route
OPEX = Operating Expenditures
SPA = Sales and Purchase Agreement
SSD = Slow Speed Diesel
TFDE = Tri-Fuel Diesel Electric
UAE = United Arab Emirates
UK = United Kingdom
US = United States
US DOE = US Department of Energy
US GOM = US Gulf of Mexico
US Lower 48 = US excluding Alaska and Hawaii
YOY = Year-on-Year

11.5. Units

Bcfd = billion cubic feet per day
bcm = billion cubic meters
cm = cubic meters
KTPA = thousand tonnes per annum
mcm = thousand cubic meters
mmcfd = million cubic feet per day
mmcm = million cubic meters
MMBtu = million British thermal units
MT = million tonnes
MTPA = million tonnes per annum
nm = nautical miles
Tcf = trillion cubic feet

11.6. Conversion Factors

← Multiply by →

	Tonnes LNG	cm LNG	mmcm gas	mmcf gas	MMBtu	boe
Tonnes LNG		2.222	0.0013	0.0459	53.38	9.203
cm LNG	0.450		5.85×10^{-4}	0.0207	24.02	4.141
mmcm gas	769.2	1,700		35.31	4,110	7,100
mmcf gas	21.78	48	0.0283		1,163	200.5
MMBtu	0.0187	0.0416	2.44×10^{-5}	8.601×10^{-4}		0.1724
boe	0.1087	0.2415	1.41×10^{-4}	0.00499	5.8	

Appendix 1: Table of Global Liquefaction Plants

Reference Number	Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
1	United States	Kenai LNG**	1969	1.5	Andeavor	ConocoPhillips Optimized Cascade®
2	Libya	Marsa El Brega LNG T1-4***	1970	3.2	LNOC	AP-C3MR™
3	Brunei	Brunei LNG T1-4	1973	5.76	Government of Brunei, Shell, Mitsubishi	AP-C3MR™
3	Brunei	Brunei LNG T5	1974	1.44	Government of Brunei, Shell, Mitsubishi	AP-C3MR™
4	United Arab Emirates	ADGAS T1-2	1977	2.6	ADNOC, Mitsui, BP, TOTAL	AP-C3MR™
5	Algeria	Arzew - GL1Z T1-6	1978	7.9	Sonatrach	AP-C3MR™
5	Algeria	Arzew - GL2Z T1-6	1981	8.2	Sonatrach	AP-C3MR™
6	Indonesia	Bontang LNG T3-4	1983	5.4	Government of Indonesia	AP-C3MR™
7	Malaysia	MLNG Satu T1-3	1983	8.4	PETRONAS, Mitsubishi, Sarawak State Government	AP-C3MR™
8	Australia	North West Shelf T1	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	AP-C3MR™
8	Australia	North West Shelf T2	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	AP-C3MR™
6	Indonesia	Bontang LNG T5	1990	2.9	Government of Indonesia	AP-C3MR™
8	Australia	North West Shelf T3	1992	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	AP-C3MR™
4	United Arab Emirates	ADGAS T3	1994	3.2	ADNOC, Mitsui, BP, TOTAL	AP-C3MR™
6	Indonesia	Bontang LNG T6	1995	2.9	Government of Indonesia	AP-C3MR™
7	Malaysia	MLNG Dua T1-3	1995	9.6	PETRONAS, Mitsubishi, Sarawak State Government	AP-C3MR™
9	Qatar	Qatargas I T1	1997	3.2	Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui	AP-C3MR™
9	Qatar	Qatargas I T2	1997	3.2	Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui	AP-C3MR™
6	Indonesia	Bontang LNG T7	1998	2.7	Government of Indonesia	AP-C3MR™
9	Qatar	Qatargas I T3	1998	3.1	Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui	AP-C3MR™
9	Qatar	RasGas I T1	1999	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	AP-C3MR™
10	Trinidad	Atlantic LNG T1	1999	3.3	Shell, BP, CIC, NGC Trinidad	ConocoPhillips Optimized Cascade®
11	Nigeria	Nigeria LNG T1	2000	3.3	NNPC, Shell, TOTAL, Eni	AP-C3MR™
12	Oman	Oman LNG T1	2000	3.55	Government of Oman, Shell, TOTAL, Mitsubishi, Mitsui, Partex, KOGAS, Hyundai, Posco, Samsung, Itochu, SK Group	AP-C3MR™
6	Indonesia	Bontang LNG T8	2000	3	Government of Indonesia	AP-C3MR™
12	Oman	Oman LNG T2	2000	3.55	Government of Oman, Shell, TOTAL, Mitsubishi, Mitsui, Partex, KOGAS, Hyundai, Posco, Samsung, Itochu, SK Group	AP-C3MR™
9	Qatar	RasGas I T2	2000	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	AP-C3MR™
11	Nigeria	Nigeria LNG T2	2000	3.3	NNPC, Shell, TOTAL, Eni	AP-C3MR™
10	Trinidad	Atlantic LNG T2	2002	3.5	Shell, BP	ConocoPhillips Optimized Cascade®
11	Nigeria	Nigeria LNG T3	2003	3	NNPC, Shell, TOTAL, Eni	AP-C3MR™
10	Trinidad	Atlantic LNG T3	2003	3.5	Shell, BP	ConocoPhillips Optimized Cascade®

Appendix 1: Table of Global Liquefaction Plants (continued)

Reference Number	Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
7	Malaysia	MLNG Tiga T1-2	2003	7.7	PETRONAS, Shell, JX Nippon Oil & Energy, Sarawak State Government, Mitsubishi, JAPEX	AP-C3MR™
9	Qatar	RasGas II T1	2004	4.7	Qatar Petroleum, ExxonMobil	AP-C3MR/SplitMR®
8	Australia	North West Shelf T4	2004	4.6	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	AP-C3MR™
13	Egypt	SEGAS LNG T1***	2005	5	Union Fenosa Gas, EGAS, EGPC	AP-C3MR/SplitMR®
13	Egypt	Egyptian LNG T1	2005	3.6	PETRONAS, Shell, EGAS, EGPC, ENGIE	ConocoPhillips Optimized Cascade®
9	Qatar	RasGas II T2	2005	4.7	Qatar Petroleum, ExxonMobil	AP-C3MR/SplitMR®
13	Egypt	Egyptian LNG T2	2005	3.6	PETRONAS, Shell, EGAS, EGPC	ConocoPhillips Optimized Cascade®
12	Oman	Qalhat LNG	2006	3.7	Government of Oman, Shell, Mitsubishi, Eni, Gas Natural Fenosa, Itochu, Osaka Gas, TOTAL, Mitsui, Partex, KOGAS, Hyundai, Posco, Samsung, SK Group	AP-C3MR™
10	Trinidad	Atlantic LNG T4	2006	5.2	Shell, BP, NGC Trinidad	ConocoPhillips Optimized Cascade®
11	Nigeria	Nigeria LNG T4	2006	4.1	NNPC, Shell, TOTAL, Eni	AP-C3MR™
11	Nigeria	Nigeria LNG T5	2006	4.1	NNPC, Shell, TOTAL, Eni	AP-C3MR™
14	Australia	Darwin LNG T1	2006	3.7	ConocoPhillips, Santos, INPEX, Eni, JERA, Tokyo Gas	ConocoPhillips Optimized Cascade®
9	Qatar	RasGas II T3	2007	4.7	Qatar Petroleum, ExxonMobil	AP-C3MR/SplitMR®
15	Equatorial Guinea	EG LNG T1	2007	3.7	Marathon, GEPetrol, Mitsui, Marubeni	ConocoPhillips Optimized Cascade®
16	Norway	Snøhvit LNG T1	2008	4.2	Statoil, Petoro, TOTAL, ENGIE, LetterOne	Linde MFC®
11	Nigeria	Nigeria LNG T6	2008	4.1	NNPC, Shell, TOTAL, Eni	AP-C3MR™
8	Australia	North West Shelf T5	2008	4.6	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	AP-C3MR™
9	Qatar	Qatargas II T1	2009	7.8	Qatar Petroleum, ExxonMobil	AP-X®
17	Russia	Sakhalin-2 T1	2009	5.4	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
17	Russia	Sakhalin-2 T2	2009	5.4	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
9	Qatar	RasGas III T1	2009	7.8	Qatar Petroleum, ExxonMobil	AP-X®
9	Qatar	Qatargas II T2	2009	7.8	Qatar Petroleum, ExxonMobil, TOTAL	AP-X®
18	Indonesia	Tangguh LNG T1	2009	3.8	BP, CNOOC, JX Nippon Oil & Energy, Mitsubishi, INPEX, KG Berau, Sojitz, Sumitomo, Mitsui	AP-C3MR/SplitMR®
19	Yemen	Yemen LNG T1***	2009	3.6	TOTAL, Hunt Oil, Yemen Gas Co., SK Group, KOGAS, Hyundai, GASSP	AP-C3MR/SplitMR®
18	Indonesia	Tangguh LNG T2	2010	3.8	BP, CNOOC, JX Nippon Oil & Energy, Mitsubishi, INPEX, KG Berau, Sojitz, Sumitomo, Mitsui	AP-C3MR/SplitMR®
9	Qatar	RasGas III T2	2010	7.8	Qatar Petroleum, ExxonMobil	AP-X®
19	Yemen	Yemen LNG T2***	2010	3.6	TOTAL, Hunt Oil, Yemen Gas Co., SK Group, KOGAS, Hyundai, GASSP	AP-C3MR/SplitMR®
20	Peru	Peru LNG T1	2010	4.45	Hunt Oil, Shell, SK Group, Marubeni	AP-C3MR/SplitMR®
9	Qatar	Qatargas III	2010	7.8	Qatar Petroleum, ConocoPhillips, Mitsui	AP-X®
9	Qatar	Qatargas IV	2011	7.8	Qatar Petroleum, Shell	AP-X®
21	Australia	Pluto LNG T1	2012	4.9	Woodside, Kansai Electric, Tokyo Gas	Shell propane pre-cooled mixed refrigerant design

Appendix 1: Table of Global Liquefaction Plants (continued)

Reference Number	Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
5	Algeria	Skikda - GL1K Rebuild	2013	4.5	Sonatrach	AP-C3MR™
22	Angola	Angola LNG T1	2014	5.2	Chevron, Sonangol, BP, Eni, TOTAL	ConocoPhillips Optimized Cascade®
23	Papua New Guinea	PNG LNG T1	2014	3.45	ExxonMobil, Oil Search, Kumul Petroleum, Santos, JX Nippon Oil & Energy, MRDC, Marubeni, Petromin PNG	AP-C3MR™
23	Papua New Guinea	PNG LNG T2	2014	3.45	ExxonMobil, Oil Search, Kumul Petroleum, Santos, JX Nippon Oil & Energy, MRDC, Marubeni, Petromin PNG	AP-C3MR™
5	Algeria	Arzew - GL3Z	2014	4.7	Sonatrach	AP-C3MR/SplitMR®
24	Australia	Queensland Curtis LNG T1	2015	4.25	Shell, CNOOC	ConocoPhillips Optimized Cascade®
24	Australia	Queensland Curtis LNG T2	2015	4.25	Shell, Tokyo Gas	ConocoPhillips Optimized Cascade®
25	Indonesia	Donggi Senoro LNG	2015	2	Mitsubishi, Pertamina, KOGAS, Medco	AP-C3MR™
26	Australia	GLNG T1	2016	3.9	Santos, PETRONAS, TOTAL, KOGAS	ConocoPhillips Optimized Cascade®
27	Australia	Australia Pacific LNG T1	2016	4.5	ConocoPhillips, Origin Energy, Sinopec	ConocoPhillips Optimized Cascade®
28	United States	Sabine Pass LNG T1	2016	4.5	Cheniere, Blackstone	ConocoPhillips Optimized Cascade®
26	Australia	GLNG T2	2016	3.9	Santos, PETRONAS, TOTAL, KOGAS	ConocoPhillips Optimized Cascade®
28	United States	Sabine Pass LNG T2	2016	4.5	Cheniere, Blackstone	ConocoPhillips Optimized Cascade®
29	Australia	Gorgon LNG T1	2016	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, JERA	AP-C3MR/SplitMR®
29	Australia	Gorgon LNG T2	2016	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, JERA	AP-C3MR/SplitMR®
7	Malaysia	MLNG T9	2017	3.6	PETRONAS, JX Nippon Oil & Energy, PTT, Sarawak State Government	AP-C3MR/SplitMR®
27	Australia	Australia Pacific LNG T2	2017	4.5	ConocoPhillips, Origin Energy, Sinopec	ConocoPhillips Optimized Cascade®
28	United States	Sabine Pass LNG T3	2017	4.5	Cheniere, Blackstone	ConocoPhillips Optimized Cascade®
29	Australia	Gorgon LNG T3	2017	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, JERA	AP-C3MR/SplitMR®
28	United States	Sabine Pass LNG T4	2017	4.5	Cheniere, Blackstone	ConocoPhillips Optimized Cascade®
30	Australia	Wheatstone LNG T1	2018	4.45	Chevron, KUFPEC, Woodside, JOGMEC, Mitsubishi, Kyushu Electric, NYK, JERA	ConocoPhillips Optimized Cascade®
31	Russia	Yamal LNG T1	2018	5.5	Novatek, CNPC, TOTAL, Silk Road Fund	AP-C3MR™

** Companies are listed by size of ownership stake, starting with the largest stake*
*** Andeavor acquired Kenai LNG from ConocoPhillips in January 2018. The plant has not exported cargoes since 2015, and future exports are uncertain.*
**** SEGAS LNG in Egypt has not exported since the end of 2012. Yemen LNG has not exported since 2015 due to an ongoing civil war. The Marsa El Brega plant in Libya is included for reference although it has not been operational since 2011.*
Sources: IHS Markit, Company Announcements

Appendix 2: Table of Liquefaction Plants Under Construction

Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*
Cameroon	Kribi FLNG	2018	2.4	Golar, Keppel
United States	Cove Point LNG	2018	5.25	Dominion
Australia	Ichthys LNG T1	2018	4.45	INPEX, TOTAL, CPC, Tokyo Gas, Kansai Electric, Osaka Gas, JERA, Toho Gas
Australia	Wheatstone LNG T2	2018	4.45	Chevron, KUFPEC, Woodside, JOGMEC, Mitsubishi, Kyushu Electric, NYK, JERA
Malaysia	PFLNG Satu	2018	1.2	PETRONAS
Indonesia	Senkang LNG T1	2018	0.5	EWC
United States	Elba Island LNG T1-6	2018	1.5	Kinder Morgan, EIG Global Energy Partners
Russia	Yamal LNG T2	2018	5.5	Novatek, CNPC, TOTAL, Silk Road Fund
Australia	Prelude FLNG	2018	3.6	Shell, INPEX, KOGAS, CPC
Australia	Ichthys LNG T2	2018	4.45	INPEX, TOTAL, CPC, Tokyo Gas, Kansai Electric, Osaka Gas, JERA, Toho Gas
Russia	Vysotsk LNG T1-2	2019	0.66	Novatek, Cryogas
Russia	Yamal LNG T3	2019	5.5	Novatek, CNPC, TOTAL, Silk Road Fund
United States	Cameron LNG T1	2019	4	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
United States	Corpus Christi LNG T1	2019	4.5	Cheniere
United States	Freeport LNG T1	2019	5.1	Freeport LNG, JERA, Osaka Gas
United States	Sabine Pass LNG T5	2019	4.5	Cheniere, Blackstone
Russia	Portovaya LNG	2019	2	Gazprom
United States	Cameron LNG T2	2019	4	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
United States	Elba Island LNG T7-10	2019	1	Kinder Morgan, EIG Global Energy Partners
United States	Corpus Christi LNG T2	2019	4.5	Cheniere
United States	Freeport LNG T2	2019	5.1	Freeport LNG, IFM Investors
United States	Cameron LNG T3	2019	4	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
Indonesia	Tangguh LNG T3	2020	3.8	BP, CNOOC, JX Nippon Oil & Energy, Mitsubishi, INPEX, KG Berau, Sojitz, Sumitomo, Mitsui
Malaysia	PFLNG Dua	2020	1.5	PETRONAS
United States	Freeport LNG T3	2020	5.1	Freeport LNG
Mozambique	Coral South FLNG	2022	3.4	Eni, ExxonMobil, CNPC, ENH, Galp Energia, KOGAS

** Companies are listed by size of ownership stake, starting with the largest stake.*
Sources: IHS Markit, Company Announcements

Appendix 3: Proposed Liquefaction Plants by Region

Project		Capacity	Status	Latest Company Announced Start Date	DOE/FERC Approval	FTA/non-FTA Approval	Operator
United States Lower 48							
Sabine Pass LNG	T3-4	9	UC**	2017	DOE/FERC	FTA/ non-FTA	Cheniere Energy
	T5	4.5	UC**	2019	DOE/FERC	FTA/ non-FTA	
	T6	4.5	Pre-FID	N/A	DOE/FERC	FTA/ non-FTA	
Cove Point LNG		5.25	UC**	2017	DOE/FERC	FTA/ non-FTA	Dominion Resources
Elba Island LNG		2.5	UC**	2018	DOE/FERC	FTA/ non-FTA	Kinder Morgan
Cameron LNG	T1-3	12	UC**	2018	DOE/FERC	FTA/ non-FTA	Sempra Energy
	T4-5	8	Pre-FID	2021	DOE/FERC	FTA/ non-FTA	
Freeport LNG	T1-2	10.2	UC**	2018-19	DOE/FERC	FTA/ non-FTA	Freeport LNG Liquefaction
	T3	5.1	UC**	2019	DOE/FERC	FTA/ non-FTA	
	T4	5.1	Pre-FID	2021	N/A	N/A	
Corpus Christi LNG	T1-2	9	UC**	2019	DOE/FERC	FTA/ non-FTA	Cheniere Energy
	T3	4.5	Pre-FID	N/A	DOE/FERC	FTA/ non-FTA	
	T4-5	9	Pre-FID	N/A	DOE	FTA	
American LNG - Titusville		0.6	Pre-FID	2017	DOE	FTA	Fortress Investment Group
Eagle LNG		0.99	Pre-FID	2018-2020	DOE	FTA	Ferus Natural Gas Fuels
Calcasieu Pass LNG		10	Pre-FID	2020	DOE	FTA	Venture Global Partners
CE FLNG		7.5	Pre-FID	2020	DOE	FTA	Cambridge Energy Holdings
Delfin FLNG		12	Pre-FID	2020	DOE	FTA	Fairwood LNG
Main Pass Energy Hub FLNG		24	Pre-FID	2020	DOE	FTA	Freeport-McMoran Energy
Plaquemines LNG		20	Pre-FID	2020	DOE	FTA	Venture Global LNG
Rio Grande LNG		27	Pre-FID	2020-22	DOE	FTA	NextDecade
Barca FLNG		12	Pre-FID	2021	DOE	FTA	Barca LNG
Eos FLNG		12	Pre-FID	2021	DOE	FTA	Eos LNG
Gulf Coast LNG		21	Pre-FID	2021	DOE	FTA	Gulf Coast LNG
Texas LNG		4	Pre-FID	2021	DOE	FTA	Texas LNG
Annova LNG		6	Pre-FID	2021-22	DOE	FTA	Exelon
Golden Pass LNG		15.6	Pre-FID	2021-22	DOE/FERC	FTA	Golden Pass Products
Gulf LNG		10	Pre-FID	2021-22	DOE	FTA	Kinder Morgan
G2 LNG		13.4	Pre-FID	2022	DOE	FTA	G2 LNG
General American LNG		4	Pre-FID	2022	N/A	N/A	General American LNG
Magnolia LNG		8	Pre-FID	2022	DOE/FERC	FTA/ non-FTA	LNG Limited
Point Comfort FLNG		9	Pre-FID	2022	N/A	N/A	Lloyds Energy Group
Driftwood LNG		26	Pre-FID	2022-25	N/A	N/A	Tellurian Investments
Port Arthur LNG		10	Pre-FID	2023	DOE	FTA	Sempra Energy
Monkey Island LNG		12	Pre-FID	2023-24	DOE	FTA	SCT&E
Jordan Cove LNG		6	Pre-FID	2024	DOE	FTA/ non-FTA	Veresen
Lake Charles LNG		15	Pre-FID	N/A	DOE/FERC	FTA/ non-FTA	Shell
Alturas LNG		1.5	Pre-FID	N/A	N/A	N/A	WesPac
Commonwealth LNG		1.25	Pre-FID	N/A	DOE	FTA	Commonwealth Projects
Avocet FLNG		N/A	Pre-FID	N/A	N/A	N/A	Fairwood LNG
Energy World Gulf Coast LNG		2	Pre-FID	N/A	N/A	N/A	EWC
Penn America Energy LNG		N/A	Pre-FID	N/A	N/A	N/A	Penn America Energy Holdings
Shoal Point LNG		N/A	Pre-FID	N/A	N/A	N/A	NextDecade

Appendix 3 (continued)

Project	Capacity	Status	Latest Company Announced Start Date	DOE/FERC Approval	FTA/non-FTA Approval	Operator
Alaska						
Alaska-Japan LNG	1	Pre-FID	2021	N/A	N/A	Resources Energy Inc.
Alaska LNG T1-3	20	Pre-FID	2025-26	DOE	FTA/ non-FTA	State of Alaska

*** UC denotes "Under Construction"*

Appendix 3 (continued)

Project		Capacity	Status	Latest Company Announced Start Date	NEB Application Status	Operator
Western Canada						
Kitsault FLNG		8	Pre-FID	2018-19	Approved	Kitsault Energy
Stewart Energy LNG	FLNG 1	5	Pre-FID	2018-19	Approved	Stewart Energy Group
	T2-6	25	Pre-FID	2020-25	Approved	
Orca FLNG	1	4	Pre-FID	2019	Approved	Orca LNG
	2-6	20	Pre-FID	N/A	Approved	
NewTimes Energy LNG		12	Pre-FID	2019-21	Approved	NewTimes Energy LNG
Cedar FLNG		6.4	Pre-FID	2020	Approved	Haisla First Nation
Woodfibre LNG		2.1	Pre-FID	2020	Approved	Pacific Oil and Gas
Pacific Northwest LNG	T1-2	12	Pre-FID	2021-22	Approved	PETRONAS
	T3	6	Pre-FID	N/A	Approved	
Grassy Point LNG		20	Pre-FID	2021	Approved	Woodside
Discovery LNG		20	Pre-FID	2021-24	Approved	Quicksilver Resources
WCC LNG	T1-3	15	Pre-FID	2025	Approved	ExxonMobil
	T4-6	15	Pre-FID	N/A	Approved	
Aurora LNG	T1-2	12	Pre-FID	2026	Approved	Nexen (CNOOC)
	T3-4	12	Pre-FID	2028	Approved	
Kitimat LNG	T1	5	Pre-FID	N/A	Approved	Chevron
	T2	5	Pre-FID	N/A		
LNG Canada	T1-2	13	Pre-FID	N/A	Approved	Shell
	T3-4	13	Pre-FID	N/A	Approved	
Malahat FLNG		6	Pre-FID	N/A	Approved	Steelhead Group
Prince Rupert LNG	T1-2	14	Pre-FID	N/A	Approved	Shell
	T3	7	Pre-FID	N/A	Approved	
Sarita LNG		24	Pre-FID	N/A	Approved	Steelhead Group
SK Group Canada LNG		N/A	Pre-FID	N/A	Not Filed	SK E&S
Watson Island LNG		N/A	Pre-FID	N/A	Not Filed	Watson Island LNG Corp.

Appendix 3 (continued)

Project	Capacity	Status	Latest Company Announced Start Date	NEB Application Status	Operator
Eastern Canada					
North Shore LNG	1	Pre-FID	2018	Approved	SLNGaz
AC LNG	15.5	Pre-FID	2020	Approved	H-Energy
Saguenay LNG	11	Pre-FID	2020	Approved	GNL Quebec
Goldboro LNG	10	Pre-FID	2021	Approved	Pierdae Energy
Bear Head LNG	12	Pre-FID	2023	Approved	LNG Limited
Canaport LNG	5	Pre-FID	Stalled	Approved	Repsol

Sources: IHS Markit, Company Announcements

Appendix 3 (continued)

Project	Capacity	Status	Latest Company Announced Start Date	Operator
Mexico				
PEMEX LNG	5	Pre-FID	2021	PEMEX
Costa Azul LNG	2	Pre-FID	2024-2025	Sempra Energy

Sources: IHS Markit, Company Announcements

Appendix 3 (continued)

Project		Capacity	Status	Latest Company Announced Start Date	Operator
Eastern Australia (CBM)					
Australia Pacific LNG T2		9	UC**	2017	ConocoPhillips
Abbot Point LNG	T1-2	1	Pre-FID	2020	EWC
	T3-4	1	Pre-FID	N/A	
Fisherman's Landing LNG T1-2		3.8	Pre-FID	N/A	LNG Limited
Offshore Australia					
Gorgon LNG	T2-3	10.4	UC**	2017	Chevron
	T4	5.2	Pre-FID	N/A	
Wheatstone LNG	T1-2	8.9	UC**	2017-18	Chevron
	T3-5	13.35	Pre-FID	N/A	
Ichthys LNG		8.9	UC**	2017-18	INPEX
Prelude FLNG		3.6	UC**	2018	Shell
Scarborough FLNG		6.5	Pre-FID	2021	ExxonMobil
Bonaparte FLNG		2	Pre-FID	N/A	ENGIE
Browse FLNG 1-3		4.5	Pre-FID	N/A	Woodside
Cash Maple FLNG		2	Pre-FID	N/A	PTTEP
Crux FLNG		2	Pre-FID	N/A	Shell
Darwin LNG T2		3.6	Pre-FID	N/A	ConocoPhillips
Poseidon FLNG		3.9	Pre-FID	N/A	ConocoPhillips
Sunrise FLNG		4	Pre-FID	N/A	Shell/Woodside
Timor Sea LNG		3	Pre-FID	N/A	MEO

*** UC denotes "Under Construction"*

Appendix 3 (continued)

Country	Project		Capacity	Latest Company Announced Start Date	Operator
Iran	Iran FLNG		0.5	2017	Unknown
Russia	Gorskaya FLNG	1-3	1.26	2017-2021	Unknown
Russia	Pechora LNG		4	2018	Altech Group
Russia	Portovaya LNG		1.5	2019	Gazprom
Djibouti	Djibouti FLNG		3	2020	Poly-GCL
Equatorial Guinea	Fortuna FLNG	1-2	4.4	2020-2025	Golar
Mozambique	Mamba LNG		10	2020-2021	Eni
Congo (Republic)	Congo-Brazzaville FLNG		1.2	2020	NewAge
Mauritania	Greater Tortue FLNG		2.5	2021	Kosmos Energy
Russia	Baltic LNG	T1-2	10	2021	Gazprom
Russia	Sakhalin-2	T3	5.4	2021	Sakhalin Energy Investment Company
Mozambique	Coral FLNG (Area 4)		3.4	2022	Eni
Papua New Guinea	PNG LNG	T3	3.45	2022	ExxonMobil
Mozambique	Mozambique LNG (Area 1)	T1-2	12	2023-2024	Anadarko
Papua New Guinea	Papua LNG	T1-2	8	2023	TOTAL
Indonesia	Abadi LNG	T1-2	9.5	2025-2026	INPEX
Russia	Arctic LNG-2	T1	6	2025	Novatek
		T2-3	12	N/A	
Tanzania	Tanzania LNG	T1-3	15	2026-2027	Statoil
		T4	5	N/A	Shell
Indonesia	East Dara FLNG		0.83	N/A	Black Platinum Energy
Nigeria	NLNG	T7-8	8.6	N/A	Nigeria LNG
Papua New Guinea	Pandora FLNG		1	N/A	Cott Oil & Gas
Russia	Sakhalin 1 LNG (Far East LNG)		5	N/A	ExxonMobil
Indonesia	Sengkang LNG	T2-4	1.5	N/A	EWC
Papua New Guinea	Western LNG T1		1.5	N/A	Repsol
Russia	Yamal LNG T4		5.5	N/A	Novatek

Appendix 4: Table of LNG Receiving Terminals

Reference Number	Country	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
1	Spain	Barcelona	1969	12.8	ENAGAS 100%	Onshore
2	Japan	Negishi	1969	12.0	TEPCO 50%; Tokyo Gas 50%	Onshore
3	US	Everett	1971	5.4	ENGIE 100%	Onshore
4	Italy	Panigaglia	1971	2.5	GNL Italia 100%	Onshore
5	France	Fos Tonkin	1972	2.2	ENGIE 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	1977	8.0	Chubu Electric 50%; Toho Gas 50%	Onshore
9	Japan	Tobata	1977	6.8	Kitakyushu LNG 100%	Onshore
10	US	Cove Point	1978	11.0	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	ENGIE 100%	Onshore
14	US	Lake Charles	1982	17.3	Energy Transfer Equity 100%	Onshore
15	Japan	Chita LNG	1983	12.0	Chubu Electric 50%; Toho Gas 50%	Onshore
16	Japan	Higashi-Ohgishima	1984	14.7	TEPCO 100%	Onshore
17	Japan	Nihonkai LNG Niigata	1984	8.9	Nihonkai LNG 58.1%; Tohoku Electric 41.9%	Onshore
18	Japan	Futtsu	1985	16.0	TEPCO 100%	Onshore
19	South Korea	Pyeongtaek	1986	40.6	KOGAS 100%	Onshore
20	Japan	Yokkaichi LNG Center	1987	7.1	Chubu Electric 100%	Onshore
21	Belgium	Zeebrugge	1987	6.6	Publigas 89.97%; Fluxys 10.03%	Onshore
22	Spain	Huelva	1988	8.9	ENAGAS 100%	Onshore
23	Spain	Cartagena (Spain)	1989	8.9	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	Yongan	1990	9.5	CPC 100%	Onshore
27	Turkey	Marmara Ereglisi	1994	5.9	Botas 100%	Onshore
28	South Korea	Incheon	1996	43.3	KOGAS 100%	Onshore
29	Japan	Sodeshi	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	2000	1.2	Gas Natural Fenosa 47.5%; ENGIE 35%; Mitsui 15%; 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	Tongyeong	2002	26.6	KOGAS 100%	Onshore

Appendix 4: Table of LNG Receiving Terminals (continued)

Reference Number	Country	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
36	Dominican Republic	Andrés	2003	1.9	AES 92%; Estrella-Linda 8%	Onshore
37	Spain	Bahia de Bizkaia Gas	2003	5.1	ENAGAS 50%; EVE 50%	Onshore
38	India	Dahej	2004	15.0	Petronet LNG 100%	Onshore
39	Portugal	Sines	2004	5.8	REN 100%	Onshore
40	UK	Grain LNG	2005	15.0	National Grid Transco 100%	Onshore
41	South Korea	Gwangyang	2005	2.3	Posco 100%	Onshore
42	India	Hazira	2005	5.0	Shell 74%; TOTAL 26%	Onshore
43	Japan	Sakai	2005	6.4	Kansai Electric 70%; Cosmo Oil 12.5%; Iwatani 12.5%; Ube Industries 5%	Onshore
44	Turkey	Aliaga	2006	4.4	Egegaz 100%	Onshore
45	Mexico	Altamira	2006	5.4	Vopak 60%; ENAGAS 40%	Onshore
46	China	Guangdong	2006	6.8	Local companies 37%; CNOOC 33%; BP 30%	Onshore
47	Japan	Mizushima	2006	1.7	Chugoku Electric 50%; JX Nippon Oil & Energy 50%	Onshore
48	Spain	Saggas (Sagunto)	2006	6.7	ENAGAS 72.5%; Osaka Gas 20%; Oman Oil 7.5%	Onshore
49	Spain	Mugardos	2007	2.6	Grupo Tojeiro 50.36%; Gobierno de Galicia 24.64%; First State Regasificadora 15%; Sonatrach 10%	Onshore
50	Mexico	Costa Azul	2008	7.5	Sempra 100%	Onshore
51	US	Freeport LNG	2008	11.3	Michael S Smith Cos 57.5%; Global Infrastructure Partners 25%; Osaka Gas 10%; Dow Chemical 7.5%	Onshore
52	China	Fujian	2008	5.0	CNOOC 60%; Fujian Investment and Development Co 40%	Onshore
53	US	Northeast Gateway	2008	0*	Excelerate Energy 100%	Floating
54	US	Sabine Pass	2008	30.2	Cheniere Energy 100%	Onshore
55	Argentina	Bahia Blanca	2008	3.8	YPF 50%; Stream JV 50%	Floating
56	Italy	Adriatic	2009	5.8	ExxonMobil 46.35%; Qatar Petroleum 46.35%; Edison 7.3%	Offshore
57	US	Cameron LNG	2009	11.3	Sempra 50.2%; ENGIE 16.6%; Mitsubishi 16.6%; Mitsui 16.6%	Onshore
58	Canada	Canaport	2009	7.5	Repsol 75%; Irving Oil 25%	Onshore
59	UK	Dragon	2009	4.4	Shell 50%; PETRONAS 30%; 4Gas 20%	Onshore
60	Kuwait	Mina Al-Ahmadi	2009	5.8	Kuwait Petroleum Corporation 100%	Floating
61	Brazil	Pecém	2009	6.0	Petrobras 100%	Floating
62	Chile	Quintero	2009	4.0	ENAGAS 60.4%; ENAP 20%; Oman Oil 19.6%	Onshore
63	China	Shanghai	2009	3.0	Shenergy Group 55%; CNOOC 45%	Onshore

Appendix 4: Table of LNG Receiving Terminals (continued)

Reference Number	Country	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
64	UK	South Hook	2009	15.6	Qatar Petroleum 67.5%; ExxonMobil 24.15%; TOTAL 8.35%	Onshore
65	Taiwan	Taichung	2009	4.5	CPC 100%	Onshore
66	Brazil	Guanabara Bay	2009	1.9	Petrobras 100%	Floating
67	UAE	Dubai	2010	6.0	Dubai Supply Authority (Dusup) 100%	Floating
68	France	Fos Cavaou	2010	6.0	ENGIE 71.5%; TOTAL 28.5%	Onshore
69	Chile	Mejillones	2010	1.5	ENGIE 63%; Codelco 37%	Onshore
70	China	Dalian	2011	6.0	CNPC 75%; Dalian Port 20%; Dalian Construction Investment Corp 5%	Onshore
71	Netherlands	GATE	2011	8.8	Gasunie 40%; Vopak 40%; Dong 5%; EconGas OMV 5%; EON 5%; RWE 5%	Onshore
72	US	Golden Pass	2011	15.6	Qatar Petroleum 70%; ExxonMobil 17.6%; ConocoPhillips 12.4%	Onshore
73	US	Gulf LNG	2011	11.3	KM LNG Operating Partnership 50%; General Electric 40%; AES 10%	Onshore
74	Argentina	Escobar	2011	3.8	Enarsa 50%; YPF 50%	Floating
75	Thailand	Map Ta Phut	2011	10.0	PTT 100%	Onshore
76	China	Jiangsu	2011	6.5	PetroChina 55%; Pacific Oil and Gas 35%; Jiangsu Guoxin 10%	Onshore
77	Indonesia	Nusantara	2012	3.8	Pertamina 60%; PGN 40%	Floating
78	Japan	Ishikari	2012	1.4	Hokkaido Gas 100%	Onshore
79	Japan	Joetsu	2012	2.3	Chubu Electric 100%	Onshore
80	Mexico	Manzanillo	2012	3.8	Mitsui 37.5%; Samsung 37.5%; KOGAS 25%	Onshore
81	China	Dongguan	2012	1.5	Jovo Group 100%	Onshore
82	Israel	Hadera Gateway	2013	3.0	Israel Natural Gas Lines 100%	Floating
83	India	Ratnagiri	2013	2.0	GAIL 31.52%; NTPC 31.52%; Indian financial institutions 20.28%; MSEB Holding Co. 16.68%	Onshore
84	Spain	El Musel	2013	5.4	ENAGAS 100%	Onshore
85	Singapore	Singapore	2013	11.0	Singapore Energy Market Authority 100%	Onshore
86	Malaysia	Sungai Udang	2013	3.8	PETRONAS 100%	Onshore
87	China	Zhejiang Ningbo	2013	3.0	CNOOC 51%; Zhejiang Energy Group Co Ltd 29%; Ningbo Power Development Co Ltd 20%	Onshore
88	China	Zhuhai	2013	3.5	CNOOC 30%; Guangdong Gas 25%; Guangdong Yuedian 25%; Local companies 20%	Onshore
89	Italy	FSRU Toscana	2013	2.7	EON 46.79%; IREN 46.79%; OLT Energy 3.73%; Golar 2.69%	Floating

Appendix 4: Table of LNG Receiving Terminals (continued)

Reference Number	Country	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
90	China	Tangshan	2013	6.5	CNPC 51%; Beijing Enterprises Group 29%; Hebei Natural Gas 20%	Onshore
91	China	Tianjin	2013	2.2	CNOOC 100%	Floating
92	Japan	Naoetsu	2013	2.0	INPEX 100%	Onshore
93	India	Kochi	2013	5.0	Petronet LNG 100%	Onshore
94	Brazil	Bahia	2014	3.8	Petrobras 100%	Floating
95	Indonesia	Lampung	2014	1.8	PGN 100%	Floating
96	South Korea	Samcheok	2014	11.6	KOGAS 100%	Onshore
97	China	Hainan	2014	2.0	CNOOC 65%; Hainan Development Holding Co 35%	Onshore
98	Japan	Hibiki	2014	3.5	Saibu Gas 90%; Kyushu Electric 10%	Onshore
99	China	Shandong	2014	3.0	Sinopec 99%; Qingdao Port Group 1%	Onshore
100	Lithuania	Klaipeda	2014	3.0	Klaipedos Nafta 100%	Floating
101	Indonesia	Arun LNG	2015	3.0	Pertamina 70%; Aceh Regional Government 30%	Onshore
102	Japan	Hachinohe	2015	1.5	JX Nippon Oil & Energy 100%	Onshore
103	Egypt	Ain Sokhna Hoegh	2015	4.2	EGAS 100%	Floating
104	Pakistan	Elengy	2015	3.8	Engro Corp. 100%	Floating
105	Jordan	Aqaba	2015	3.8	Jordan Ministry of Energy and Mineral Resources (MEMR) 100%	Floating
106	Egypt	Ain Sokhna BW	2015	0*	EGAS 100%	Floating
107	Japan	Shin-Sendai	2015	1.5	Tohoku Electric 100%	Onshore
108	Japan	Hitachi	2016	1.0	Tokyo Gas 100%	Onshore
109	China	Beihai	2016	3.0	Sinopec 100%	Onshore
110	Poland	Swinoujscie	2016	3.6	GAZ-SYSTEM SA 100%	Onshore
111	UAE	Abu Dhabi	2016	3.8	ADNOC 100%	Floating
112	Colombia	Cartagena (Colombia)	2016	3.0	Promigas 51%; Baru LNG 49%	Floating
113	France	Dunkirk	2017	9.5	EDF 65%; Fluxys 25%; TOTAL 10%	Onshore
114	South Korea	Boryeong	2017	3.0	GS Group 50%; SK Group 50%	Onshore
115	Turkey	Etki	2017	5.3	Etki Liman Isletmeleri Dolgalgaz Ithalat ve Ticaret 100%	Floating
116	Egypt	Sumed BW	2017	5.7	EGAS 100%	Floating
117	China	Yuedong	2017	2.0	CNOOC 100%	Onshore
118	Malaysia	RGT2 (Pengerang)	2017	3.5	PETRONAS 65%; Dialog Group 25%; Johor Government 10%	Onshore
119	Pakistan	PGPC Port Qasim	2017	5.7	Pakistan LNG Terminals Limited 100%	Floating
120	China	Tianjin (Sinopec)	2018	2.9	Sinopec 100%	Onshore
121	Japan	Soma	2018	1.5	JAPEX 100%	Onshore

**Existing floating terminals that did not have an associated FSRU charter as of March 2018 but have not been officially decommissioned are included in the above list, though regasification capacity is shown as 0.*
Sources: IHS Markit, Company Announcements

Appendix 5: Table of LNG Receiving Terminals Under Construction

Reference Number	Country	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
122	China	Shenzhen (Diefu)	2018	4.0	CNOOC 70%; Shenzhen Energy Group 30%	Onshore
123	India	Mundra	2018	5.0	GSPC 50%; Adani Group 50%	Onshore
124	Turkey	Dortyol	2018	4.1	BOTAS 100%	Floating
125	Bangladesh	Moheshkhali LNG (Petrobangla)	2018	3.8	Petrobangla 100%	Floating
126	China	Chaozhou	2018	1.0	Sinoenergy 55%; Chaozhou Huafeng Group 45%	Onshore
127	China	Zhoushan	2018	3.0	ENN Energy 100%	Onshore
128	India	Jaigarh	2018	4.0	H-Energy 100%	Floating
129	Philippines	Pagbilao LNG	2018	3.0	Energy World Corporation 100%	Onshore
130	India	Ennore LNG	2018	5.0	Indian Oil Corporation 95%; Tamil Nadu Industrial Development Corporation 5%	Onshore
131	Panama	Costa Norte LNG	2018	1.5	AES 100%	Floating
132	China	Tianjin	2018	3.5	CNOOC 100%	Onshore
133	Russia	Kaliningrad LNG	2018	1.5	Gazprom 100%	Floating
134	Bahrain	Bahrain LNG	2019	6.0	NOGA 30%; Teekay Corp 30%; Gulf Investment Corporation (GIC) 20%; Samsung 20%	Floating
135	China	Yangjiang	2019	2.0	Pacific Oil and Gas 50%; Guangdong Yudean 50%	Onshore
136	Brazil	Sergipe	2020	3.6	Ebrasil 50%; Golar Power 50%	Floating
137	India	Jafrabad LNG Port	2020	5.0	Exmar 38%; Gujarat Government 26%; Swan Energy 26%; Tata Group 10%	Floating
138	China	Shenzhen (CNPC)	2020	3.0	CNPC 51%; CLP 24.5%; Shenzhen Gas 24.5%	Onshore
139	Kuwait	Al Zour	2021	11.3	Kuwait Petroleum Corporation 100%	Onshore
140	China	Zhangzhou	2022	3.0	CNOOC 60%; Fujian Investment and Development Company 40%	Onshore

Note: Under construction expansion projects at existing terminals are not included in these totals.
Sources: IHS Markit, Company Announcements

Appendix 6: Table of Active Fleet, end-2017

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	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	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	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

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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
AMADI	Brunei Gas Carriers	Hyundai	Conventional	2015	155,000	Steam Reheat	9682552
AMALI	Brunei Gas Carriers	Daewoo	Conventional	2011	147,228	TFDE	9496317
AMANI	Brunei Gas Carriers	Hyundai	Conventional	2014	155,000	TFDE	9661869
AMUR RIVER	Dynagas	Hyundai	Conventional	2008	146,748	Steam	9317999
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 ENDEAVOUR	Chevron	Samsung	Conventional	2015	154,948	TFDE	9610779
ASIA ENERGY	Chevron	Samsung	Conventional	2014	154,948	TFDE	9606950
ASIA EXCELLENCE	Chevron	Samsung	Conventional	2015	154,948	TFDE	9610767
ASIA INTEGRITY	Chevron	Samsung	Conventional	2017	154,948	TFDE	9680188
ASIA VENTURE	Chevron	Samsung	Conventional	2017	154,948	TFDE	9680190
ASIA VISION	Chevron	Samsung	Conventional	2014	154,948	TFDE	9606948
BARCELONA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2009	173,400	TFDE	9401295
BEBATIK	Shell	Chantiers de l'Atlantique	Conventional	1972	75,056	Steam	7121633
BEIDOU STAR	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	172,000	MEGI	9613159
BELANAK	Shell	Ch.De La Ciotat	Conventional	1975	75,000	Steam	7347768
BERGE ARZEW	BW	Daewoo	Conventional	2004	138,089	Steam	9256597
BERING ENERGY	General Dynamics	General Dynamics	Conventional	1978	126,750	Steam	7390155
BILBAO KNUTSEN	Knutsen OAS	IZAR	Conventional	2004	135,049	Steam	9236432
BISHU MARU	Trans Pacific Shipping	Kawasaki Sakaide	Conventional	2017	164,700	Steam Reheat	9691137
BORIS VILKITSKY	Sovcomflot	Daewoo	Conventional	2017	172,000	TFDE	9768368
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
BROOG	J4 Consortium	Mitsui	Conventional	1998	136,359	Steam	9085651

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
BU SAMRA	Nakilat	Samsung	Q-Max	2008	260,928	SSD	9388833
BW BOSTON	BW, ENGIE	Daewoo	Conventional	2003	138,059	Steam	9230062
BW GDF SUEZ BRUSSELS	BW	Daewoo	Conventional	2009	162,514	DFDE	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
BW PAVILION LEEARA	BW	Hyundai	Conventional	2015	161,880	TFDE	9640645
BW PAVILION VANDA	BW Pavilion LNG	Hyundai	Conventional	2015	161,880	TFDE	9640437
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
CESI BEIHAI	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	TFDE	9672844
CESI GLADSTONE	Chuo Kaiun/Shinwa Chem.	Hudong-Zhonghua	Conventional	2016	174,000	TFDE	9672820
CESI QINGDAO	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	TFDE	9672832
CESI TIANJIN	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	DFDE	9694749
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
CHRISTOPHE DE MARGERIE	Sovcomflot	Daewoo	Conventional	2016	170,000	TFDE	9737187
CLEAN ENERGY	Dynagas	Hyundai	Conventional	2007	146,794	Steam	9323687
CLEAN HORIZON	Avoca Maritime Corp Ltd	Hyundai	Conventional	2015	162,000	TFDE	9655444
CLEAN OCEAN	Dynagas	Hyundai	Conventional	2014	162,000	TFDE	9637492
CLEAN PLANET	Dynagas	Hyundai	Conventional	2014	162,000	TFDE	9637507
CLEAN VISION	Dynagas	Hyundai	Conventional	2016	162,000	TFDE	9655456
COOL EXPLORER	Thenamaris	Samsung	Conventional	2015	160,000	TFDE	9640023
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
CREOLE SPIRIT	Teekay	Daewoo	Conventional	2016	173,400	MEGI	9681687
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

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
DUKHAN	J4 Consortium	Mitsui	Conventional	2004	137,672	Steam	9265500
DWIPUTRA	P.T. Humpuss Trans	Mitsubishi	Conventional	1994	127,386	Steam	9043677
EDUARD TOLL	Teekay	Daewoo	Conventional	2017	172,000	TFDE	9750696
EJNAN	K Line, MOL, NYK, Mitsui, Nakilat	Samsung	Conventional	2007	143,815	Steam	9334076
EKAPUTRA 1	P.T. Humpuss Trans	Mitsubishi	Conventional	1990	136,400	Steam	8706155
ENERGY ADVANCE	Tokyo Gas	Kawaski	Conventional	2005	144,590	Steam	9269180
ENERGY ATLANTIC	Alpha Tankers	STX	Conventional	2015	157,521	TFDE	9649328
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	Mitsubishi, MOL, Chubu Electric	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
EXCELSIOR	Exmar	Daewoo	FSRU	2005	138,000	Steam	9239616
EXPRESS	Exmar, Excelerate	Daewoo	FSRU	2009	150,900	Steam	9361445
FEDOR LITKE	Sovcomflot	Daewoo	Conventional	2017	172,000	TFDE	9768370
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
GANDRIA	Golar LNG	HDW	Conventional	1977	123,512	Steam	7361934
GASELYS	GDF SUEZ, NYK	Chantiers de l'Atlantique	Conventional	2007	151,383	DFDE	9320075
GASLOG CHELSEA	GasLog	Hanjin H.I.	Conventional	2010	153,600	DFDE	9390185
GASLOG GENEVA	GasLog	Samsung	Conventional	2016	174,000	TFDE	9707508
GASLOG GIBRALTAR	GasLog	Samsung	Conventional	2016	174,000	TFDE	9707510
GASLOG GLASGOW	GasLog	Samsung	Conventional	2016	174,000	TFDE	9687021
GASLOG GREECE	GasLog	Samsung	Conventional	2016	170,520	TFDE	9687019
GASLOG SALEM	GasLog	Samsung	Conventional	2015	155,000	TFDE	9638915
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 POINT FORTIN	MOL, Sumitomo, LNG JAPAN	Imabari	Conventional	2010	154,982	Steam	9375721
GEMMATA	Shell	Mitsubishi	Conventional	2004	135,269	Steam	9253222

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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
GLOBAL ENERGY	GDF SUEZ	Chantiers de l'Atlantique	Conventional	2004	74,130	Steam	9269207
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 FROST	Golar LNG	Samsung	Conventional	2014	160,000	TFDE	9655042
GOLAR GLACIER	ICBC	Hyundai	Conventional	2014	162,500	TFDE	9654696
GOLAR GRAND	Golar LNG Partners	Daewoo	Conventional	2005	145,700	Steam	9303560
GOLAR ICE	ICBC	Samsung	Conventional	2015	160,000	TFDE	9637325
GOLAR KELVIN	ICBC	Hyundai	Conventional	2015	162,000	TFDE	9654701
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
GOLAR SNOW	ICBC	Samsung	Conventional	2015	160,000	TFDE	9635315
GOLAR SPIRIT	Golar LNG Partners	Kawasaki Sakaide	Converted FSRU	1981	129,000	Steam	7373327
GOLAR TUNDRA	Golar LNG	Samsung	FSRU	2015	170,000	TFDE	9655808
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
GRACE ENERGY	Sinokor Merchant Marine	Mitsubishi	Conventional	1989	127,580	Steam	8702941
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 PYEONGTAEK	Hanjin Shipping Co.	Hanjin H.I.	Conventional	1995	130,366	Steam	9061928
HANJIN SUR	Hanjin Shipping Co.	Hanjin H.I.	Conventional	2000	138,333	Steam	9176010
HISPANIA SPIRIT	Teekay	Daewoo	Conventional	2002	137,814	Steam	9230048
HL RAS LAFFAN	Hanjin Shipping Co.	Hanjin H.I.	Conventional	2000	138,214	Steam	9176008
HOEGH GIANT	Hoegh	Hyundai	FSRU	2017	170,000	DFDE	9762962
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 PEACEPIA	Hyundai LNG Shipping	Daewoo	Conventional	2017	174,000	MEGI	9761853
HYUNDAI PRINCEPIA	Hyundai LNG Shipping	Daewoo	Conventional	2017	174,000	MEGI	9761841
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

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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
KUMUL	MOL, China LNG	Hudong-Zhonghua	Conventional	2016	169,147	SSD	9613161
LA MANCHA KNUTSEN	Knutsen OAS	Hyundai	Conventional	2016	176,300	MEGI	9721724
LALLA FATMA N'SOUMER	HYPROC	Kawaski	Conventional	2004	144,888	Steam	9275347
LENA RIVER	Dynagas	Hyundai	Conventional	2013	154,880	TFDE	9629598
LIJMILIYA	Nakilat	Daewoo	Q-Max	2009	258,019	SSD	9388819
LNG ABALAMABIE	Nigeria LNG Ltd	Samsung	Conventional	2016	170,000	MEGI	9690171
LNG ABUJA II	Nigeria LNG Ltd	Samsung	Conventional	2016	175,180	DFDE	9690169
LNG ADAMAWA	BGT Ltd.	Hyundai	Conventional	2005	142,656	Steam	9262211
LNG AKWA IBOM	BGT 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	BGT Ltd.	Hyundai	Conventional	2003	137,500	Steam	9241267
LNG BENUE	BW	Daewoo	Conventional	2006	142,988	Steam	9267015
LNG BONNY II	Nigeria LNG Ltd	Hyundai	Conventional	2015	177,000	DFDE	9692002
LNG BORNO	NYK	Samsung	Conventional	2007	149,600	Steam	9322803
LNG CROSS RIVER	BGT Ltd.	Hyundai	Conventional	2005	142,656	Steam	9262223
LNG DREAM	NYK	Kawaski	Conventional	2006	147,326	Steam	9277620
LNG EBISU	MOL, KEPCO	Kawaski	Conventional	2008	147,546	Steam	9329291
LNG ENUGU	BW	Daewoo	Conventional	2005	142,988	Steam	9266994
LNG FINIMA II	Nigeria LNG Ltd	Samsung	Conventional	2015	170,000	DFDE	9690145
LNG FLORA	NYK, Osaka Gas	Kawaski	Conventional	1993	125,637	Steam	9006681
LNG FUKUROKUJU	MOL, KEPCO	Kawasaki Sakaide	Conventional	2016	164,700	Steam Reheat	9666986
LNG IMO	BW	Daewoo	Conventional	2008	148,452	Steam	9311581
LNG JAMAL	NYK, Osaka Gas	Mitsubishi	Conventional	2000	136,977	Steam	9200316
LNG JUPITER	Osaka Gas, NYK	Kawaski	Conventional	2009	152,880	Steam	9341689
LNG JUROJIN	MOL, KEPCO	Mitsubishi	Conventional	2015	155,300	Steam Reheat	9666998
LNG KANO	BW	Daewoo	Conventional	2007	148,565	Steam	9311567
LNG KOLT	STX Pan Ocean	Hanjin H.I.	Conventional	2008	153,595	Steam	9372963
LNG LAGOS II	Nigeria LNG Ltd	Hyundai	Conventional	2016	177,000	DFDE	9692014
LNG LERICI	ENI	Sestri	Conventional	1998	63,993	Steam	9064085
LNG LOKOJA	BW	Daewoo	Conventional	2006	148,471	Steam	9269960
LNG MALEO	MOL, NYK, K Line	Mitsui	Conventional	1989	127,544	Steam	8701791
LNG MARS	Osaka Gas, MOL	Mitsubishi	Conventional	2016	153,000	Steam Reheat	9645748
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

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
LNG PIONEER	MOL	Daewoo	Conventional	2005	138,000	Steam	9256602
LNG PORT-HARCOURT II	Nigeria LNG Ltd	Samsung	Conventional	2015	170,000	MEGI	9690157
LNG PORTOVENERE	ENI	Sestri	Conventional	1996	65,262	Steam	9064073
LNG RIVER NIGER	BGT Ltd.	Hyundai	Conventional	2006	142,656	Steam	9262235
LNG RIVER ORASHI	BW	Daewoo	Conventional	2004	142,988	Steam	9266982
LNG RIVERS	BGT Ltd.	Hyundai	Conventional	2002	137,500	Steam	9216298
LNG SATURN	MOL	Mitsubishi	Conventional	2016	153,000	Steam Reheat	9696149
LNG SOKOTO	BGT Ltd.	Hyundai	Conventional	2002	137,500	Steam	9216303
LNG VENUS	Osaka Gas, MOL	Mitsubishi	Conventional	2014	155,300	Steam	9645736
LNG VESTA	Tokyo Gas, MOL, Iino	Mitsubishi	Conventional	1994	127,547	Steam	9020766
LOBITO	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	TFDE	9490961
LUSAIL	K Line, MOL, NYK, Nakilat	Samsung	Conventional	2005	142,808	Steam	9285952
MACOMA	Teekay	Daewoo	Conventional	2017	173,400	MEGI	9705653
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 ACHILLES	Maran Gas Maritime	Hyundai	Conventional	2015	174,000	MEGI	9682588
MARAN GAS AGAMEMNON	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	MEGI	9682590
MARAN GAS ALEXANDRIA	Maran Gas Maritime	Hyundai	Conventional	2015	164,000	TFDE	9650054
MARAN GAS AMPHIPOLIS	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9701217
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 HECTOR	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	TFDE	9682605
MARAN GAS LINDOS	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	TFDE	9627502
MARAN GAS MYSTRAS	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	TFDE	9658238
MARAN GAS OLYMPIAS	Maran Gas Maritime	Daewoo	Conventional	2017	173,400	TFDE	9732371
MARAN GAS PERICLES	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	DFDE	9709489
MARAN GAS POSIDONIA	Maran Gas Maritime	Hyundai	Conventional	2014	164,000	TFDE	9633434
MARAN GAS ROXANA	Maran Gas Maritime	Daewoo	Conventional	2017	173,400	TFDE	9701229
MARAN GAS SPARTA	Maran Gas Maritime	Hyundai	Conventional	2015	162,000	TFDE	9650042
MARAN GAS TROY	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	TFDE	9658240
MARAN GAS ULYSSES	Maran Gas Maritime	Hyundai	Conventional	2017	174,000	SSD	9709491
MARIA ENERGY	Tsakos	Hyundai	Conventional	2016	174,000	TFDE	9659725
MARIB SPIRIT	Teekay	Samsung	Conventional	2008	163,280	DFDE	9336749

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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	GasLog	Samsung	Conventional	2007	145,000	Steam	9321768
METHANE BECKI ANNE	GasLog	Samsung	Conventional	2010	167,416	TFDE	9516129
METHANE HEATHER SALLY	GasLog	Samsung	Conventional	2007	145,000	Steam	9321744
METHANE JANE ELIZABETH	GasLog	Samsung	Conventional	2006	145,000	Steam	9307190
METHANE JULIA LOUISE	Mitsui & Co	Samsung	Conventional	2010	167,416	TFDE	9412880
METHANE KARI ELIN	Shell	Samsung	Conventional	2004	136,167	Steam	9256793
METHANE LYDON VOLNEY	Shell	Samsung	Conventional	2006	145,000	Steam	9307205
METHANE MICKIE HARPER	Shell	Samsung	Conventional	2010	167,400	TFDE	9520376
METHANE NILE EAGLE	Shell, Gaslog	Samsung	Conventional	2007	145,000	Steam	9321770
METHANE PATRICIA CAMILA	Shell	Samsung	Conventional	2010	167,416	TFDE	9425277
METHANE PRINCESS	Golar LNG Partners	Daewoo	Conventional	2003	136,086	Steam	9253715
METHANE RITA ANDREA	Shell, Gaslog	Samsung	Conventional	2006	145,000	Steam	9307188
METHANE SHIRLEY ELISABETH	Shell, Gaslog	Samsung	Conventional	2007	142,800	Steam	9321756
METHANE SPIRIT	Teekay, Marubeni	Samsung	Conventional	2008	163,195	TFDE	9336737
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
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
MUREX	Teekay	Daewoo	Conventional	2017	173,400	MEGI	9705641
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
NKOSSA II	AP Moller	Mitsubishi	Conventional	1992	78,488	Steam	9003859
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

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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
OAK SPIRIT	Teekay	Daewoo	Conventional	2016	173,400	MEGI	9681699
OB RIVER	Dynagas	Hyundai	Conventional	2007	146,791	Steam	9315692
ONAIZA	Nakilat	Daewoo	Q-Flex	2009	205,963	SSD	9397353
OUGARTA	HYPROC	Hyundai	Conventional	2017	171,800	TFDE	9761267
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
PAN ASIA	Teekay	Hudong-Zhonghua	Conventional	2017	174,000	DFDE	9750220
PAPUA	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	172,000	TFDE	9613135
POLAR SPIRIT	Teekay	I.H.I.	Conventional	1993	88,100	Steam	9001772
PRACHI	NYK	Hyundai	Conventional	2016	173,000	TFDE	9723801
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 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	MEGI	9443413
RIBERA DEL DUERO KNUTSEN	Knutsen OAS	Daewoo	Conventional	2010	173,400	TFDE	9477593
RIOJA KNUTSEN	Knutsen OAS	Hyundai	Conventional	2016	176,300	MEGI	9721736
SALALAH LNG	OSC, MOL	Samsung	Conventional	2005	148,174	Steam	9300817

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
SCF MELAMPUS	Sovcomflot	STX	Conventional	2015	170,200	TFDE	9654878
SCF MITRE	Sovcomflot	STX	Conventional	2015	170,200	TFDE	9654880
SEISHU MARU	Mitsubishi, NYK, Chubu Electric	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
SERI CAMELLIA	PETRONAS	Hyundai	Conventional	2016	150,200	Steam Reheat	9714276
SERI CEMPAKA	PETRONAS	Hyundai	Conventional	2017	150,200	MEGI	9714290
SERI CENDERAWASIH	PETRONAS	Hyundai	Conventional	2017	150,200	Steam Reheat	9714288
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 AUDACE	SK Shipping, Marubeni	Samsung	Conventional	2017	180,000	XDF	9693161
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
SM EAGLE	Korea Line	Daewoo	Conventional	2017	174,000	MEGI	9761827
SM SEAHAWK	Korea Line	Daewoo	Conventional	2017	174,000	MEGI	9761839
SOHAR LNG	OSC, MOL	Mitsubishi	Conventional	2001	135,850	Steam	9210816
SOLARIS	GasLog	Samsung	Conventional	2014	155,000	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
SOUTHERN CROSS	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	169,295	Steam Reheat	9613147
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
SUNRISE	Shell	Dunkerque Ateliers	Conventional	1977	126,813	Steam	7359670

Appendix 6: Table of Active Fleet, end-2017 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
SYMPHONIC BREEZE	K Line	Kawaski	Conventional	2007	145,394	Steam	9330745
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 LIMA	MISC	CNIM	Conventional	1981	127,409	Steam	7428445
TESSALA	HYPROC	Hyundai	Conventional	2016	171,800	TFDE	9761243
TORBEN SPIRIT	Teekay	Daewoo	Conventional	2017	173,400	MEGI	9721401
TRADER	BP	Samsung	Conventional	2002	138,248	Steam	9238038
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
WILPRIDE	Teekay	Daewoo	Conventional	2013	156,007	TFDE	9627966
WOODSIDE CHANEY	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	SSD	9682576
WOODSIDE DONALDSON	Teekay, Marubeni	Samsung	Conventional	2009	162,620	TFDE	9369899
WOODSIDE GOODE	Maran Gas Maritime	Daewoo	Conventional	2013	159,800	TFDE	9633161
WOODSIDE REES WITHERS	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9732369
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 Markit, Company Announcements

Appendix 7: Table of LNG Vessel Orderbook, end-2017

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
BAHRAIN SPIRIT	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9771080
BORIS DAVYDOV	Sovcomflot	Daewoo	Conventional	2018	172,000	TFDE	9768394
BRITISH PARTNER	BP	Daewoo	Conventional	2018	174,000	MEGI	9766530
BUSHU MARU	NYK	Mitsubishi	Conventional	2018	180,000	TFDE	9796793
BW COURAGE	BW	Daewoo	FSRU	2018	173,400	MEGI	9792591
BW IRIS	BW	Daewoo	Conventional	2019	173,400	MEGI	9792606
BW LILAC	BW	Daewoo	Conventional	2018	174,300	MEGI	9758076
BW TULIP	BW	Daewoo	Conventional	2018	174,300	MEGI	9758064
CASTILLO DE CALDELAS	Elcano	Imabari	Conventional	2018	178,000	MEGI	9742819
CASTILLO DE MERIDA	Elcano	Imabari	Conventional	2018	178,000	MEGI	9742807
CESI LIANYUNGANG	China Shipping Group	Hudong-Zhonghua	Conventional	2018	174,000	MEGI	9672818
CESI WENZHOU	China Shipping Group	Hudong-Zhonghua	Conventional	2018	174,000	TFDE	9694751
DAEWOO 2432	MOL	Daewoo	Conventional	2018	172,000	TFDE	9750660
DAEWOO 2442	BP	Daewoo	Conventional	2018	174,000	MEGI	9766542
DAEWOO 2443	BP	Daewoo	Conventional	2018	174,000	MEGI	9766554
DAEWOO 2444	BP	Daewoo	Conventional	2018	174,000	MEGI	9766566
DAEWOO 2445	BP	Daewoo	Conventional	2019	174,000	MEGI	9766578
DAEWOO 2446	BP	Daewoo	Conventional	2019	174,000	MEGI	9766580
DAEWOO 2466	Maritima Del Norte	Daewoo	Conventional	2019	170,000	-	9810367
DAEWOO 2467	Maran Gas Maritime	Daewoo	Conventional	2019	170,000	-	9810379
DAEWOO 2469	Maran Gas Maritime	Daewoo	Conventional	2020	169,540	-	9844863
DAEWOO 2477	Maran Gas Maritime	Daewoo	FSRU	2020	173,400	-	9820843
DAEWOO 2478	Maran Gas Maritime	Daewoo	Conventional	2020	169,540	-	9845013
DIAMOND GAS ORCHID	NYK	Mitsubishi	Conventional	2018	165,000	TFDE	9779226
DIAMOND GAS ROSE	NYK	Mitsubishi	Conventional	2018	165,000	XDF	9779238
ENERGY LIBERTY	MOL	Japan Marine	Conventional	2018	165,000	TFDE	9736092
FLEX CONSTELLATION	Frontline Management	Daewoo	Conventional	2019	173,400	MEGI	9825427
FLEX COURAGEOUS	Frontline Management	Daewoo	Conventional	2019	173,400	MEGI	9825439
FLEX ENDEAVOUR	Frontline Management	Daewoo	Conventional	2018	173,400	MEGI	9762261
FLEX ENTERPRISE	Frontline Management	Daewoo	Conventional	2018	174,000	MEGI	9762273
FLEX RAINBOW	Flex LNG	Samsung	Conventional	2018	174,000	MEGI	9709037
FLEX RANGER	Flex LNG	Samsung	Conventional	2018	174,000	MEGI	9709025
GASLOG GENOA	GasLog	Samsung	Conventional	2018	174,000	MEGI	9744013
GASLOG GLADSTONE	GasLog	Samsung	Conventional	2019	174,000	MEGI	9744025

Appendix 7: Table of LNG Vessel Orderbook, end-2017

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
GASLOG HONG KONG	GasLog	Hyundai	Conventional	2018	174,000	MEGI	9748904
GASLOG HOUSTON	GasLog	Hyundai	Conventional	2018	174,000	MEGI	9748899
GASLOG WINDSOR	GasLog	Samsung	Conventional	2019	180,000	-	9816763
GEORGIY BRUSILOV	Sovcomflot	Daewoo	Conventional	2018	172,000	TFDE	9768382
GEORGIY USHAKOV	Teekay	Daewoo	Conventional	2020	172,000	TFDE	9750749
GOLAR NANOOK	Golar LNG	Samsung	FSRU	2018	170,000	DFDE	9785500
HOEGH ESPERANZA	Hoegh	Hyundai	FSRU	2018	170,000	DFDE	9780354
HUDONG-ZHONGHUA H1810A	MOL	Hudong-Zhonghua	Conventional	2019	174,000	DFDE	9834296
HUDONG-ZHONGHUA H1811A	MOL	Hudong-Zhonghua	Conventional	2020	174,000	DFDE	9834301
HUDONG-ZHONGHUA H1812A	MOL	Hudong-Zhonghua	Conventional	2020	174,000	DFDE	9834313
HUDONG-ZHONGHUA H1813A	MOL	Hudong-Zhonghua	Conventional	2020	170,000	DFDE	9834325
HYUNDAI SAMHO 8006	Albus Shipping	Hyundai	Conventional	2020	174,000	-	9849887
HYUNDAI ULSAN 2909	Hoegh	Hyundai	FSRU	2018	166,630	DFDE	9822451
HYUNDAI ULSAN 2945	Kolin / Kalyon	Hyundai	FSRU	2019	167,042	DFDE	9823883
HYUNDAI ULSAN 2963	Knutsen OAS	Hyundai	Conventional	2019	180,000	-	9831220
HYUNDAI ULSAN 2964	Knutsen OAS	Hyundai	Conventional	2019	180,000	MEGI	9825568
HYUNDAI ULSAN 2993	Triumph Offshore Pvt Ltd	Hyundai	FSRU	2019	180,000	DFDE	9837066
HYUNDAI ULSAN 3020	TMS Cardiff Gas	Hyundai	Conventional	2020	174,000	-	9845764
HYUNDAI ULSAN 3021	TMS Cardiff Gas	Hyundai	Conventional	2020	174,000	-	9845776
HYUNDAI ULSAN 3022	TMS Cardiff Gas	Hyundai	Conventional	2020	174,000	-	9845788
IMABARI SAIJO 8215	0	Imabari	Conventional	2022	178,000	MEGI	9789037
IMABARI SAIJO 8216	0	Imabari	Conventional	2022	178,000	MEGI	9789049
IMABARI SAIJO 8217	0	Imabari	Conventional	2022	178,000	MEGI	9789051
JMU TSU 5071	NYK	Japan Marine	Conventional	2018	165,000	TFDE	9752565
JMU TSU 5072	MOL	Japan Marine	Conventional	2018	165,000	MEGI	9758832
JMU TSU 5073	MOL	Japan Marine	Conventional	2018	165,000	MEGI	9758844
KAWASAKI SAKAIDE 1720	K Line	Kawaski	Conventional	2018	164,700	XDF	9749609
KAWASAKI SAKAIDE 1728	Mitsui & Co	Kawasaki Sakaide	Conventional	2018	155,000	XDF	9759240
KAWASAKI SAKAIDE 1729	Mitsui & Co	Kawasaki Sakaide	Conventional	2019	155,000	TFDE	9759252
KAWASAKI SAKAIDE 1734	MOL, Chubu Electric	Kawasaki Sakaide	Conventional	2018	177,000	DFDE	9791200
KAWASAKI SAKAIDE 1735	NYK/Chubu Electric	Kawasaki Sakaide	Conventional	2018	177,000	DFDE	9791212
KINISIS	Chandris Group	Daewoo	Conventional	2018	173,400	MEGI	9785158

Appendix 7: Table of LNG Vessel Orderbook, end-2017

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
LNG SAKURA	NYK/Kepco	Kawasaki Sakaide	Conventional	2018	177,000	TFDE	9774135
LNG SCHNEEWEISSCHEN	Mitsui & Co	Daewoo	Conventional	2018	180,000	-	9771913
MAGDALA	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9770921
MARAN GAS CHIOS	Maran Gas Maritime	Daewoo	Conventional	2019	173,400	MEGI	9753014
MARAN GAS HYDRA	Maran Gas Maritime	Daewoo	Conventional	2019	173,400	MEGI	9767962
MARAN GAS SPETSES	Maran G.M, Nakilat	Daewoo	Conventional	2018	173,400	MEGI	9767950
MARAN GAS SYROS	Maran Gas Maritime	Daewoo	Conventional	2019	174,000	DFDE	9753026
MARSHAL VASILEVSKIY	Gazprom JSC	Hyundai	FSRU	2018	174,000	TFDE	9778313
MARVEL CRANE	NYK	Mitsubishi	Conventional	2018	177,000	TFDE	9770438
MARVEL FALCON	Mitsui & Co	Samsung	Conventional	2018	174,000	MEGI	9760768
MARVEL HAWK	Mitsui & Co	Samsung	Conventional	2018	174,000	MEGI	9760770
MARVEL SWAN	K Line	Imabari	Conventional	2020	178,000	MEGI	9778923
MEGARA	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9770945
MITSUBISHI NAGASAKI 2322	Mitsui & Co	Mitsubishi	Conventional	2018	177,000	TFDE	9770440
MITSUBISHI NAGASAKI 2323	MOL	Mitsubishi	Conventional	2018	180,000	TFDE	9774628
MITSUBISHI NAGASAKI 2326	MOL	Mitsubishi	Conventional	2018	180,000	TFDE	9796781
MITSUBISHI NAGASAKI 2332	0	Mitsubishi	Conventional	2019	165,000	-	9810020
MYRINA	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9770933
NIKOLAY YEVGENOV	Teekay	Daewoo	Conventional	2019	172,000	TFDE	9750725
NIKOLAY ZUBOV	Sovcomflot	Daewoo	Conventional	2018	172,000	TFDE	9768526
OCEANIC BREEZE	K-Line, Inpex	Mitsubishi	Conventional	2018	153,000	Steam Reheat	9698111
PACIFIC BREEZE	K Line	Kawaski	Conventional	2018	182,000	TFDE	9698123
PACIFIC MIMOSA	NYK	Mitsubishi	Conventional	2018	155,300	Steam Reheat	9743875
PAN AFRICA	Teekay	Hudong-Zhonghua	Conventional	2019	174,000	DFDE	9750256
PAN AMERICAS	Teekay	Hudong-Zhonghua	Conventional	2018	174,000	DFDE	9750232
PAN EUROPE	Teekay	Hudong-Zhonghua	Conventional	2018	174,000	DFDE	9750244
PATRIS	Chandris Group	Daewoo	Conventional	2018	174,000	MEGI	9766889
PRISM AGILITY	SK Shipping	Hyundai	Conventional	2019	180,000	DFDE	9810549
PRISM BRILLIANCE	SK Shipping	Hyundai	Conventional	2019	180,000	DFDE	9810551
RUDOLF SAMOYLOVICH	Teekay	Daewoo	Conventional	2018	172,000	TFDE	9750713
SAGA DAWN	Landmark Capital Ltd	Xiamen Shipbuilding Industry	Conventional	2018	45,000	-	9769855
SAMSUNG 2150	Mitsui & Co	Samsung	Conventional	2018	174,000	MEGI	9760782

Appendix 7: Table of LNG Vessel Orderbook, end-2017

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
SAMSUNG 2213	GasLog	Samsung	Conventional	2019	180,000	-	9819650
SAMSUNG 2220	Hoegh	Samsung	FSRU	2019	170,000	DFDE	9820013
SEAN SPIRIT	Teekay	Hyundai	Conventional	2019	174,000	MEGI	9781918
SERI CAMAR	PETRONAS	Hyundai	Conventional	2018	150,200	Steam Reheat	9714305
SERI CEMARA	PETRONAS	Hyundai	Conventional	2018	150,200	Steam Reheat	9756389
SK RESOLUTE	SK Shipping, Marubeni	Samsung	Conventional	2018	180,000	SSD	9693173
SK SERENITY	SK Shipping	Samsung	Conventional	2018	174,000	DFDE	9761803
SK SPICA	SK Shipping	Samsung	Conventional	2018	174,000	MEGI	9761815

Sources: IHS Markit, Company Announcements

Appendix 8: Table of FSRUs, Laid-Up Carriers, and Floating Storage Units, end-2017

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #	Status at end-2017
BW INTEGRITY	BW	Samsung	FSRU	2017	170,000	TFDE	9724946	Chartered as FSRU
BW SINGAPORE	BW	Samsung	FSRU	2015	170,000	TFDE	9684495	Chartered as FSRU
EXCELERATE	Exmar, Excelerate	Daewoo	FSRU	2006	135,313	Steam	9322255	Chartered as FSRU
EXCELLENCE	Excelerate Energy	Daewoo	FSRU	2005	138,124	Steam	9252539	Chartered as FSRU
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
EXPLORER	Exmar, Excelerate	Daewoo	FSRU	2008	150,900	Steam	9361079	Chartered as FSRU
EXQUISITE	Excelerate Energy	Daewoo	FSRU	2009	151,035	Steam	9381134	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	DFDE	9390680	Chartered as FSRU
GOLAR ESKIMO	Golar LNG	Samsung	FSRU	2014	160,000	TFDE	9624940	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 WINTER	Golar LNG Partners	Daewoo	Converted FSRU	2004	138,000	Steam	9256614	Chartered as FSRU
HOEGH GALLANT	Hoegh	Hyundai	FSRU	2014	170,000	TFDE	9653678	Chartered as FSRU
HOEGH GRACE	Hoegh	Hyundai	FSRU	2016	170,000	DFDE	9674907	Chartered as FSRU
INDEPENDENCE	Hoegh	Hyundai	FSRU	2014	170,132	TFDE	9629536	Chartered as FSRU
MOL FSRU CHALLENGER	MOL	Daewoo	FSRU	2017	263,000	TFDE	9713105	Chartered as FSRU
NEPTUNE	Hoegh, MOL, TLTC	Samsung	FSRU	2009	145,130	Steam	9385673	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
ADRIATIC ENERGY	Sinokor Merchant Marine	Mitsubishi	Conventional	1983	125,568	Steam	8110203	Laid-up
ATLANTIC ENERGY	Sinokor Merchant Marine	Kockums	Conventional	1984	132,588	Steam	7702401	Laid-up

Appendix 8: Table of FSRUs, Laid-Up Carriers, and Floating Storage Units, end-2017

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #	Status at end-2017
BALTIC ENERGY	Sinokor Merchant Marine	Kawaski	Conventional	1983	125,929	Steam	8013950	Laid-up
CARIBBEAN ENERGY	Golar LNG	General Dynamics	Conventional	1980	126,530	Steam	7619575	Laid-up
FORTUNE FSU	Dalian Inteh	Dunkerque Normandie	Conventional	1981	130,000	Steam	7428471	Laid-up
GCL	Hoegh	General Dynamics	Conventional	1979	126,000	Steam	7413232	Laid-up
GOLAR VIKING	Golar LNG	Hyundai	Conventional	2005	140,000	Steam	9256767	Laid-up
GULF ENERGY	General Dynamics	General Dynamics	Conventional	1978	126,750	Steam	7390143	Laid-up
LNG CAPRICORN	Nova Shipping & Logistics	General Dynamics	Conventional	1978	126,750	Steam	7390208	Laid-up
LNG TAURUS	Nova Shipping & Logistics	General Dynamics	Conventional	1979	126,750	Steam	7390167	Laid-up
LNG VIRGO	General Dynamics	General Dynamics	Conventional	1979	126,750	Steam	7390179	Laid-up
LUCKY FSU	Dalian Inteh	Dunkerque Normandie	Conventional	1981	127,400	Steam	7428469	Laid-up
MEDITERRANEAN ENERGY	Sinokor Merchant Marine	Mitsubishi	Conventional	1984	126,975	Steam	8125832	Laid-up
NORTH ENERGY	Sinokor Merchant Marine	Mitsubishi	Conventional	1983	125,788	Steam	8014409	Laid-up
OCEAN QUEST	GDF SUEZ	Newport News	Conventional	1979	126,540	Steam	7391214	Laid-up
PACIFIC ENERGY	Sinokor Merchant Marine	Kockums	Conventional	1981	132,588	Steam	7708948	Laid-up
PUTERI FIRUS	MISC	Chantiers de l'Atlantique	Conventional	1997	127,689	Steam	9030840	Laid-up
SOUTH ENERGY	Sinokor Merchant Marine	General Dynamics	Conventional	1980	126,750	Steam	7619587	Laid-up
WEST ENERGY	Sinokor Merchant Marine	Chantiers de l'Atlantique	Conventional	1976	122,255	Steam	7360124	Laid-up
ARMADA LNG MEDITERRANA	Bumi Armada Berhad	Mitsui	FSU	2016	127,209	Steam	8125868	FSU
TENAGA EMPAT	MISC	CNIM	FSU	1981	130,000	Steam	7428433	FSU
TENAGA SATU	MISC	Dunkerque Chantiers	FSU	1982	130,000	Steam	7428457	FSU

Sources: IHS Markit, Company Announcements

Notes

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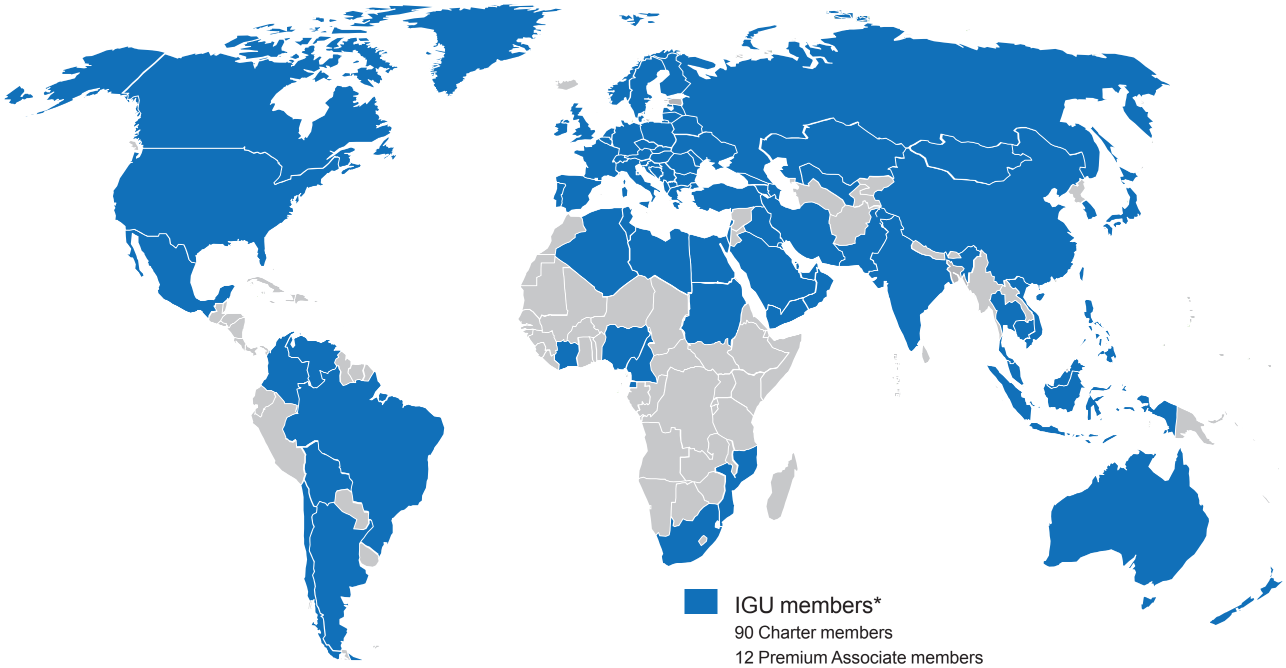

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