IGU
INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ

2019 WORLD LNG REPORT

Sponsored by

Shell
KOGAS KOREA GAS CORPORATION
AGA American Gas Association
enagas

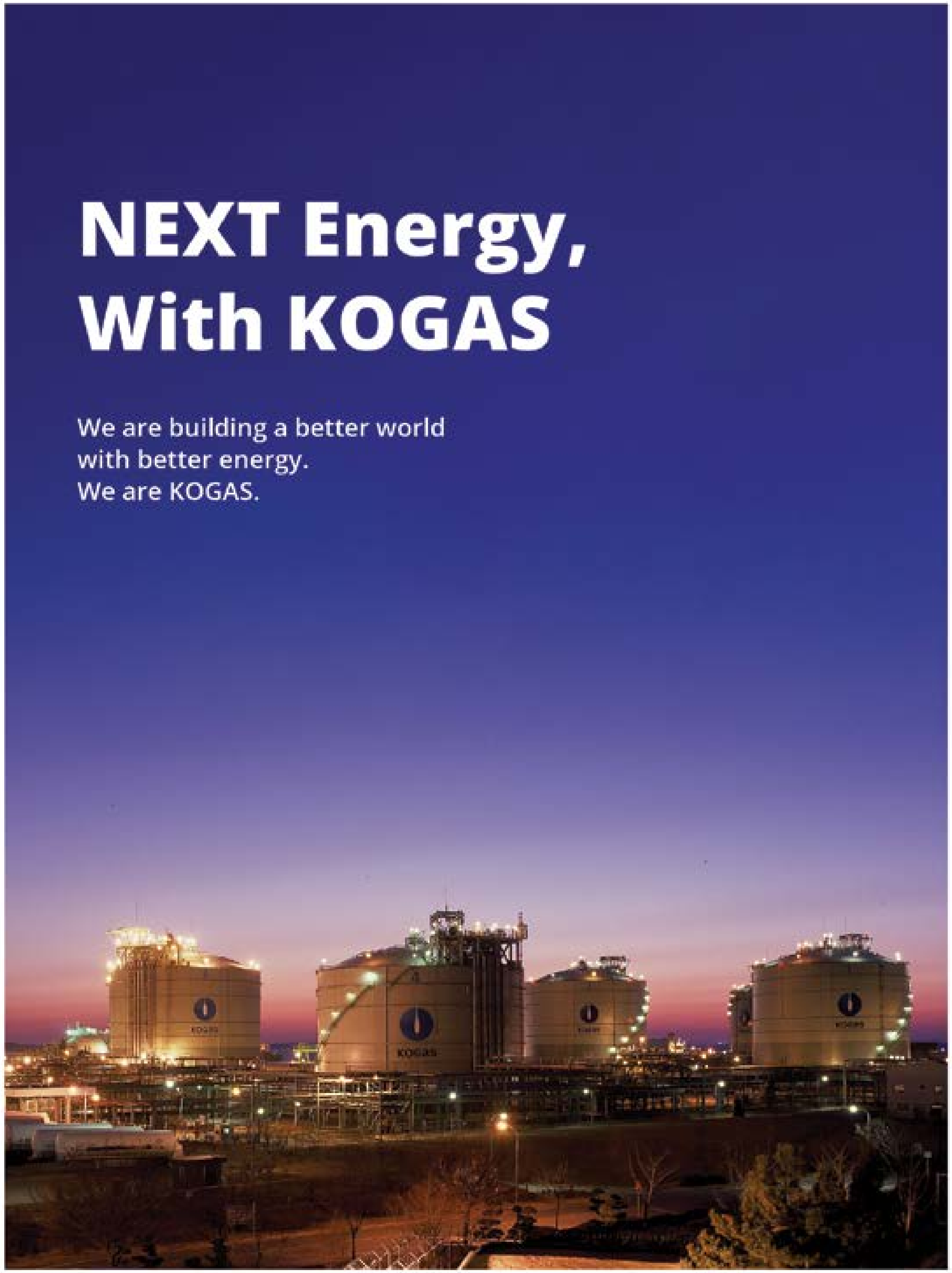


TABLE OF CONTENTS

MESSAGE FROM THE PRESIDENT OF THE INTERNATIONAL GAS UNION

Dear colleagues,

It is my honour to have been named President of the International Gas Union (IGU) for the 2018-2021 triennium. I look forward to building on the great work that has been done under previous Presidencies, and to intensifying collective efforts to advance the role of liquefied natural gas (LNG) in a sustainable energy future. The IGU is pleased to present the 2019 World LNG Report at LNG19 in Shanghai, highlighting physical and market developments in the LNG industry around the world.

The report demonstrates that 2018 was another strong year for LNG by a range of metrics. For the fifth consecutive year, global LNG trade set a record, reaching 316.5 million tonnes (MT). This marks an increase of 28.2 MT (+9.8% year-on-year) from 2017. Specifically, non-long-term LNG trade reached 99 MT in 2018, an increase of 14.5 MT year-on-year (YOY) and accounted for 31% of total gross LNG trade. This substantial expansion can be attributed to increasingly flexible LNG supply. Most LNG-related prices around the world followed an upward trend in 2018, influenced by rising oil prices and strong LNG demand in Asia. China and South Korea continued to lead demand growth driven by policies to improve air quality.

Global liquefaction build-out was driven largely by capacity additions in Australia, the United States, and Russia. Between January 2018 and February 2019, 36.2 MTPA of liquefaction capacity was added. In an engineering milestone, the first project utilizing a floating liquefaction conversion, Kribi FLNG in Cameroon, was brought online.

2018 marked a positive turn for project developers. Four projects took FIDs in 2018 (Corpus Christi LNG T3, LNG Canada, Greater Tortue FLNG and Tango FLNG), with a number of significant projects expected to reach FIDs in 2019.

The overall global LNG fleet grew by 11.5% in 2018, and spot charter rates soared. As 51.8 MTPA of new liquefaction capacity is expected to start up in 2019, the shipping market may become tighter with only 43 newbuild deliveries targeted in the year.

Global regasification capacity has continued to increase, rising to 824 MTPA by February 2019. Of the under-construction capacity, 36.4 MTPA of much needed capacity is anticipated online during 2019, much of it in India and China. Both markets, however, have struggled to develop related infrastructure at the same pace, causing challenges for gas to flow to demand centres.

The future looks bright for LNG, and we expect 2019 to be a benchmark year for the industry, with growth in trade and investment. A vibrant LNG industry, and the increased use of natural gas in general, brings great benefits to society. It improves security of electricity supply and offers opportunities to meet emissions targets and facilitate vital access to energy in diverse markets around the globe. It also has a significant impact on improving quality of life by reducing air pollution, especially as population growth continues. A combination of natural gas and renewables will allow the developing world to meet the Paris commitments affordably, without sacrificing economic growth.

Our aim at the IGU is to demonstrate that natural gas has a vital environmental and economic role to play in the sustainable energy future, and that the industry is open to co-operate with the global community towards achieving this future.

Yours sincerely,

Joe M. Kang
President of the International Gas Union

2. State of the LNG Industry[1]

Barcelona LNG Terminal - Courtesy of Enagas

Global Trade

316.5 MT
Global trade in 2018

For the fifth consecutive year, global LNG trade set a record, reaching 316.5 million tonnes (MT). This marks an increase of 28.2 MT from 2017, equating to 9.8% year-on-year (YOY) growth. The continued growth in trade was supported by increases in LNG output from liquefaction plants ramping-up and coming online, more than offsetting lower production from several legacy projects. Australia led all exporters in incremental growth (+12.2 MT), supported by the new Wheatstone LNG and Ichthys LNG projects. The United States was again the second-largest driver of LNG supply growth, adding 8.2 MT as trains at Sabine Pass LNG operated for the full year and Cove Point LNG came online. Asia remained the driver of international LNG demand growth, as China broke its own record for incremental LNG by importing an additional 15.8 MT in 2018. This was again driven by the strong enforcement of environmental policies designed to promote coal-to-gas switching as well as continued economic growth. Other key markets that drove global LNG growth included South Korea, India, and Pakistan, which took in a combined 12.8 MT of incremental imports. The Pacific Basin continues to be the key driver of trade growth, with intra-Pacific trade flows reaching a record 134.2 MT, supported by Australian production and Chinese demand.

Short, Medium, and Long-term LNG Market (as defined in Chapter 10)

99 MT
Non-long-term trade, 2018

Non-long-term LNG trade reached 99 MT in 2018, an increase of 14.5 MT YOY, and accounted for 31% of total gross LNG trade. This marks the second year in a row that the non-long-term market has substantially expanded, which can be attributed to growing LNG supply and demand elasticity. As with total global trade, short-term supply and demand growth was strongest in the Pacific Basin. New liquefaction capacity added during the year was contracted mostly to aggregators with diverse LNG trading portfolios. Particularly notable was the increase in short-term supply from Australia, which had the largest increase in non-long-term exports (+6.4 MT) despite holding long-term contracts directly with many end-markets. The largest growth in non-long-term imports was in China, which took in an additional 10 MT YOY from the short-term market as buyers relied heavily on the spot market to satisfy their strong demand growth.

Global Prices

$9.78 /MMBtu
Average Northeast Asian spot price, 2018

Most LNG-related prices around the world followed an upward trend in 2018, influenced by rising oil prices and strong LNG demand in Asia. Several price markers experienced some volatility in the spring and summer months, but a cold winter at the start of the year and active spot buying in China kept prices generally elevated; although Northeast Asian spot prices fell from an average $9.88 per million British thermal units (MMBtu) in January 2018 to a low of $7.20/MMBtu in May 2018, this was 36% higher than their level in May 2017. While this resurgence is notable, spot prices showed some signs of weakness toward the end of 2018, as a thus far mild winter in Asia and Europe, coupled with the continued ramp-up of new supply, started to place downward pressure on spot prices, with average Northeast Asian spot prices falling by 18% between November 2018 and January 2019, landing at $9.36/MMBtu. European spot prices climbed for most of the year, though a large influx of LNG in the fourth quarter of the year began to place some downward pressure on market prices like the United Kingdom's National Balancing Point (NBP), compounded by the fall in oil prices. After hitting a peak of $9.54/MMBtu in September 2018 – over 50% higher than its level in the previous year – NBP began to decline in October and had reached $7.44/MMBtu by January 2019. As new liquefaction capacity is added in 2019, prices could fall further, particularly during traditional seasonal lulls in demand in the spring and summer months.

Liquefaction plants

393 MTPA
Global nominal liquefaction capacity, February 2019

Global liquefaction capacity remains in the extended phase of build-out that began in 2016, driven largely by capacity additions in Australia, the United States, and Russia. Between January 2018 and February 2019, 36.2 million tonnes per annum (MTPA) of liquefaction capacity was added, though 5.6 MTPA was assumed to be decommissioned. In an engineering first, the first project utilizing a floating liquefaction conversion, Kribi FLNG in Cameroon, was brought online. The market where the most liquefaction capacity was added during 2018 was Russia, with 11 MTPA of capacity reaching commercial operations across Yamal LNG T1-2, while Yamal LNG T3 reached commercial operations in February 2019. After Russia, the most capacity was added in Australia, where two trains at Wheatstone LNG reached commercial operations in 2018. By mid-2019, the final projects in Australia's recent build-out, Ichthys LNG and Prelude FLNG, are expected to have reached full commercial operations (a combined 12.5 MTPA). Still, the United States is poised to surpass them both in incremental liquefaction capacity as it brings online over 29 MTPA of liquefaction capacity during 2019. As of February 2019, 101.3 MTPA of liquefaction capacity was under-construction or sanctioned. With increasing optimism for LNG import needs during the 2020s, 21.5 MTPA of liquefaction capacity reached a final investment decision (FID) in 2018. This includes 14 MTPA of capacity at LNG Canada T1-2 and 4.5 MTPA at Corpus Christ LNG T3. Most recently, FID was reached on the 15.6 MTPA Golden Pass LNG project in February 2019, the largest single FID since 16.5 MTPA of capacity at Yamal LNG T1-3 was sanctioned in December 2013.

[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.

Gemmata - Courtesy of Shell

New Liquefaction Proposals

843 MTPA
Proposed liquefaction capacity, February 2019

After a challenging environment for FIDs in recent years, 2018 marked a positive turn for project developers. Many projects that remained under development during these years could now be posed to reach FID in 2019. As of February 2019, the total liquefaction capacity of proposed projects reached 845 MTPA, with the majority in the United States and Canada. Beyond those two markets, projects based on massive resource bases have continued to sign offtake agreements or attract new partners which will help reach FID, as is the case in Mozambique and Russia. Qatar has also proposed expanding capacity in the 2020s to ensure it is the largest liquefaction capacity holder in the world. With currently under-construction projects expected to contribute to strong global supply during the 2019-2022 period, many developers are targeting the mid-2020s as the next period in which to bring new liquefaction capacity online. Despite increased optimism in future LNG demand growth, much proposed liquefaction capacity will be challenged by fierce competition for LNG buyers, project financing, and available engineering, procurement, and construction (EPC) contractors.

Regasification Terminals

824 MTPA
Global nominal regasification capacity, February 2019

Global regasification capacity has continued to increase, rising to 824 MTPA by February 2019. Unlike in 2017, regasification capacity additions did not outpace increases in liquefaction capacity and global trade, with a total 6.2 MTPA of net regasification capacity added during 2018 (22.8 MTPA of new additions minus 16.6 MTPA from floating storage and regasification unit (FSRU) departures over the course of the year). Much of this capacity was added in China (10.6 MTPA), where suppliers sought to increase regasification in preparation for the 2018-2019 winter after the market had higher than expected demand in the 2017-2018 winter. Two regasification terminals were added in new markets, Panama and Bangladesh, bringing the number of global LNG markets to 36[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 both in mature markets that are experiencing increased gas demand, as well as in new markets where governments have made developing gas demand a priority. There is an additional 129.7 MTPA of regasification capacity under construction as of February 2019. This includes capacity across several new markets, such as Bahrain, the Philippines, Russia (Kaliningrad), and Ghana. Of under-construction capacity, 36.4 MTPA of capacity is anticipated online during 2019, much of it in India and China. The single-largest under-construction project is in Kuwait, with 11.3 MTPA of regasification capacity expected online in 2021.

[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 totals.

Shipping Fleet

525 Vessels
LNG fleet, end-2018

The global LNG shipping fleet consisted of 525 vessels at the end of 2018, including conventional vessels and ships acting as FSRUs and floating storage units. The overall global LNG fleet grew by 11.5% in 2018, as 53 carriers were added to the fleet, including four FSRUs. Relative to the previous year, this was a more balanced addition relative to liquefaction capacity, and charter rates for modern fuel-efficient tonnage started the year strong owing to an increase in winter LNG demand in China. After dipping in the spring and summer months to an average of $56,000/day, there was a significant uptick in charter rates owing to the build-up of winter LNG inventories in Northeast Asian markets, with rates soaring to an average $150,000/day in Q4 2018. However, this was short-lived, and spot charter rates had already returned to around $74,000/day by January 2019. Even with the decline from end-2018, it is unlikely that charter rates will return to their 2017 levels as new liquefaction capacity continues to be added to the market, which will help keep rates higher.

Floating Regasification

80.1 MTPA[3]
FSRU capacity, February 2019

Despite the start-up of two offshore projects during 2018, total regasification capacity at operational offshore terminals decreased to 80.1 MTPA. This was due to four FSRUs departing from existing offshore terminals in Brazil, Egypt, the United Arab Emirates, and Argentina (a reduction of 16.6 MTPA). Charters of two FSRUs ended as well, in Kuwait and at Tianjin, China. However, the terminal in the former is likely to receive a replacement vessel, and the latter has already received a replacement FSRU, which boosted receiving capacity at the terminal. As of February 2019, twelve offshore projects were under construction. These terminals are spread between new markets, such as Ghana and Russia (Kaliningrad) and more mature markets, such as India and Brazil. Projects have even been proposed in Australia, a major LNG exporter, with one project signing a time charter for an FSRU in December 2018 to meet periodic surges in gas demand. As of February 2019, twelve FSRUs (including conversions) 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 offshore terminals.

LNG in the global gas market

10.7% of Supply
Share of LNG in global gas supply in 2017[4]

Natural gas accounts for just under a quarter of global energy demand, of which 10.7% is supplied as LNG. LNG supply previously grew faster than any other natural gas supply source – averaging 8.3% per annum from 2000 to 2010, although growth stalled in the early 2010s as indigenous production and pipeline supply competed for growing global gas markets. The large increases in global liquefaction capacity and international LNG trade have enabled a return to robust growth in LNG consumption. The 10.7% share of total gas consumption for LNG in 2017 marks the second consecutive year of share growth and a new record.

With the increasing importance of environmental regulation globally, interest in the use of natural gas and LNG in marine shipping is continuing to grow. Companies are ordering and taking delivery of smaller LNG bunkering vessels, which load LNG from regasification terminals or other small-scale facilities to directly fuel the expanding fleet of LNG-fuelled vessels. Although each individual cargo is small, in aggregate these volumes are anticipated to grow consistently, with sectoral demand potentially surpassing 25 MTPA by 2030.

[3] This 80.1 MTPA is included in the global regasification capacity total of 824 MTPA quoted above.
[4] Data for pipeline trade and indigenous gas production comes from the BP Statistical Review. Data for 2018 is not yet available.

3.
LNG Trade

Global LNG trade increased sharply in 2018

Increased by
28.2MT

Setting a new annual record of
316.5MT

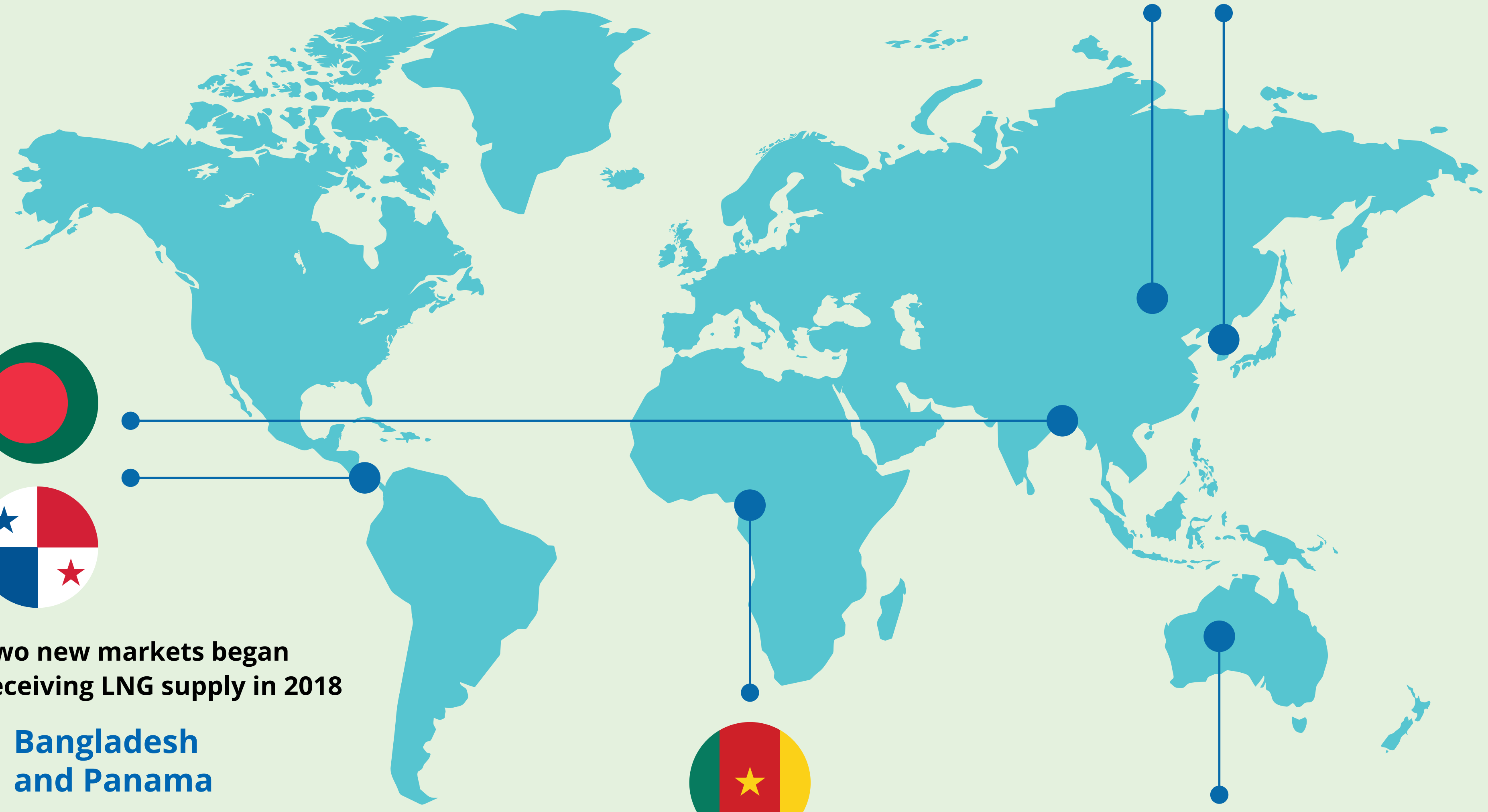
5th
consecutive year of incremental growth

3rd
largest annual increase ever (behind only 2010 and 2017)

LNG import growth in 2018 was driven by China and South Korea, the world's second- and third-largest LNG importers.

Represented nearly **80%** of the increase in net trade

Combined incremental growth of **22.2MT**



Two new markets began receiving LNG supply in 2018

Bangladesh and Panama

Cameroon

Joined the club of LNG exporters with the world's second floating liquefaction project

Australia led all exporters in

incremental growth

Global trade increased sharply again in 2018, following a strong performance in 2017, rising by 28.2 MT to reach 316.5 MT. This marks the fifth consecutive year of incremental growth, and the third-largest annual increase ever (behind only 2010 and 2017). The increase was driven by higher production at new liquefaction plants in Australia, the United States, and Russia. Legacy projects had mixed results, with production falling in Malaysia owing to pipeline issues. Beyond large exporters adding new liquefaction trains, Cameroon joined the club of LNG exporters with the world's second floating liquefaction project coming online during the first half of 2018. As was the case in 2017, LNG import growth in 2018 was driven by China and South Korea, the world's second- and third-largest LNG importers. Two new markets began receiving LNG supply in 2018: Bangladesh and Panama.

China and South Korea returned as the drivers of LNG import demand in 2018, following incremental growth of 12.0 and 4.2 MT in 2017, respectively, with growth of 15.8 and 6.4 MT in 2018. Their combined incremental growth of 22.2 MT in 2018 represented nearly 80% of the increase in net trade; this builds on what had already been an impressive 50% in 2017. The 15.8 MT of incremental import growth in China was the largest ever for a single market, surpassing a mark that was also set by China only in 2017. In contrast, LNG imports declined by 3.7 MT in Egypt as domestic gas production from the Zohr field and the West Nile Delta region surged. Egypt had previously been a key driver of LNG demand growth, rising to 7.3 MT of imports in 2016 despite only receiving its first cargo during 2015. Both China and Egypt are examples of the shifts that can occur in LNG import patterns where LNG is used flexibly as an alternative to other gas supply sources.

Supply is poised to rise again in 2019 as global liquefaction capacity remains in a period of expansion. Growth in international LNG trade during 2019 is likely to be driven by the same set of markets as in 2018, with Australia concluding its multi-year expansion, full-year performance of new Russian projects, and the United States adding new trains and projects throughout the year. Import demand growth is expected to be driven by markets across Asia, including China, India, Pakistan, and Bangladesh. The ability of markets to absorb new incremental supply may be tested absent demand stimuli, which could push more LNG into regions with ample natural gas infrastructure and market liquidity. This trend began to manifest during the final quarter of 2018, with record LNG imports into Europe for a fourth quarter. New markets are also likely to provide small pockets of import demand growth, particularly via the use of rapidly-deployable FSRUs or floating storage units as is expected to be the case in Russia (Kaliningrad) and Bahrain, respectively.

LNG Carrier Pyeongtaek - Courtesy of KOGAS

3.1 OVERVIEW

Globally-traded LNG volumes increased by 28.2 MT in 2018, setting a new annual record of 316.5 MT[1] (see Figure 3.1). Combined with 2017, this marks the strongest two-year growth period for international LNG demand since 2010-11. Similarly-strong growth is anticipated in 2019 as a wave of projects sanctioned in 2013-15 come online and others reach nameplate production capacity.

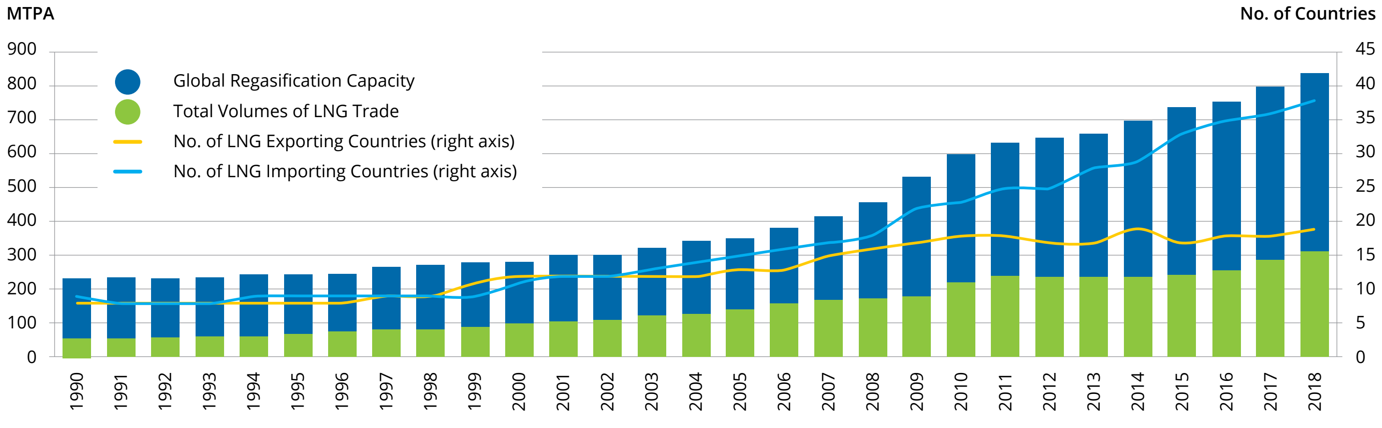
316.5 MT
Global LNG trade reached a historic high in 2018

In 2018, the number of LNG-exporting markets rose to 19 as the 2.4 MTPA Kribi FLNG project came online in Cameroon. Political instability in Yemen has continued to prevent the resumption of LNG exports since they were halted in mid-2015. The single greatest increase in LNG exports occurred again in Australia (+12.2 MT), owing to new trains coming on-stream, and higher utilization at existing facilities. The other primary contributors to incremental LNG supply were the United States and Russia, which added 8.2 and 7.8 MT, respectively, across new and existing trains. After falling during 2017, global re-export activity increased by 46% YOY, with 3.9 MT re-exported by 11 markets during the year (the same set of 11 markets that re-exported LNG in 2017).

The Asia-Pacific region[2] continues to be the leading LNG-exporting region, supplying 38.4% of total exports (121.6 MT). This share is consistent with its share of global exports since 2016, when it became the largest LNG-exporting region after being second to the Middle East from 2010-15. Growth in exports from the Asia-Pacific was supported both by new trains coming online and higher production from existing trains in Australia. Production from existing projects declined from most other Asia-Pacific exporters, including Malaysia, Indonesia, Brunei, and Papua New Guinea (down a combined 4.4 MT YOY in 2018). Lower production in Papua New Guinea was caused by the plant going offline for several months in the first half of the year after an earthquake caused damage to associated infrastructure.

Although the Asia-Pacific has grown in importance as an LNG-exporting region in recent years, Qatar remained the largest LNG-exporting market by a sizeable, but shrinking margin. The market accounted for around 25% of total global LNG exports in 2018 (78.7 MT). Australia was second with 22% of global supply (68.6 MT of exports).

Figure 3.1 LNG Trade Volumes, 1990-2018



Source: IHS Markit, IEA, IGU

The United States continued its expected ramp-up of exports, rising by 8.2 MT as Cove Point LNG came online and production increased at trains at Sabine Pass LNG. Additionally, the first commissioning cargoes from Corpus Christ LNG were lifted during the final quarter of the year. There were mixed results across the rest of the Atlantic Basin. LNG exports declined in Nigeria and Algeria by 0.6 MT and 1.9 MT, respectively; the latter may have been impacted by higher sales of pipeline gas to Europe. New upstream projects that came online in Trinidad throughout 2017 resulted in production rising to 12.2 MT in 2018, nearly recovering to 2015 levels. Stronger performances were also recorded at projects in Norway and Angola, along with new production from Cameroon's Kribi FLNG (a combined +1.7 MT YOY). An improved gas balance allowed for more LNG exports to be loaded from Egypt during the year as well (1.4 MT was exported in 2018); this figure could rise again in 2019.

[1] Owing to improved data availability and partial-cargo tracking methodology, some historical trade numbers have been restated.
[2] Please refer to Chapter 10: References for an exact definition of each region.

Imports into Asia-Pacific and Asia markets (the distinction between these regions is illustrated in Section 10.3) increased again during 2018. However, due to the significant growth in China and support from other regional markets, Asia was the only region to increase its share of global imports, rising by 5.3 percentage points to 27.1% of total trade. The other Asian markets to experience strong incremental growth were India (+4.0 MT), Pakistan (+2.4 MT), and Bangladesh (+0.7 MT). In the Asia-Pacific region, import growth was driven primarily by South Korea (+6.4 MT), with small additions in Thailand, Singapore, and Chinese Taipei (+1.5 MT). However, with Japanese imports contracting slightly, the region's share of LNG import trade fell under 50% for the first time since the mid-1970s.

The addition of Bangladesh and Panama brought the number of importing markets to 37, with the pair recording a combined 0.9 MT of imports.[3] Looking forward, a handful of new markets are expected to start importing LNG during 2019, including Bahrain and Russia (Kaliningrad). Incremental growth is also anticipated across most markets that came online in 2015-18. In contrast, improving natural gas supply balances in markets such as Egypt and Argentina are likely to reduce the need for LNG imports in those markets. Given expectations of seasonal gas surplus in Argentina, LNG import reliance may also fall in neighbouring Chile, to which pipeline gas exports restarted late in 2018. In fact, a previously-idle floating liquefaction vessel is expected to allow LNG exports from Argentina during 2019, although they will likely amount to less than 0.5 MT of incremental supply.

European LNG imports increased YOY for the fourth consecutive year (+3.4 MT). This increase occurred despite net negative incremental growth through the first three quarters of the year, as the fourth quarter of the year was the second strongest quarter ever for net imports into the region (behind Q1 2011). In both absolute and relative terms, the strongest gains were experienced in the North-western European markets of the Netherlands and Belgium, which had incremental growth of 1.3 MT and 1.4 MT (+184% and +132% YOY), respectively. Incremental LNG import growth was repeated in other well-connected and mature European gas markets, including France, Italy, and Turkey (combined +1.5 MT YOY), while the UK arrested its two-year slide, with imports rising to 5.0 MT (+0.3 MT YOY). Three European LNG markets contracted by a combined 2.1 MT in 2018: Spain, Greece, and Lithuania.

There was limited incremental growth in LNG imports on a regional level in North America and Latin America in 2018 (+0.3 MT YOY for each region). Of all markets in the two regions, the strongest incremental growth was in Brazil (+0.4 MT YOY), due to domestic issues that necessitated LNG to meet temporary gaps in supply that domestic production could not fill. Other gains were experienced in Puerto Rico (the United States), where demand recovered after a low year in 2017 caused by Hurricane Maria, as well as LNG for power sector consumption in Colombia and Panama. With an improving natural gas balance in Argentina, lower LNG imports were required in that market as well as in neighbouring Chile, which was able to import gas from its neighbour on the Southern Cone.

European LNG imports during 2019 are likely to be shaped by dynamics that began to emerge towards the end of 2018, including readily-available LNG supply, decreasing European domestic gas production, and increasing gas demand, including both industrial sector growth and competition between gas and coal in the power sector. If these conditions persist, high levels of LNG could be delivered to the interconnected and highly-liquid natural gas markets across Europe. However, the behaviour of pipeline suppliers will be a major factor in determining how much LNG arrives at European terminals. Even after exporting record volumes to Europe during 2018, Russia retains additional export capacity, which could result in increased competition with LNG, particularly if global LNG prices rise on higher demand.

From a supply perspective, the balance of new production is expected to continue shifting towards the Atlantic Basin during 2019. New projects in the United States and Russia are likely to have strong incremental growth throughout the year. The last two projects in Australia's current expansion queue – Prelude FLNG and Ichthys LNG T2 – will come online during the year as well. In all three markets, trains that came online during 2018 will benefit from being run for the full year during 2019.

2017-2018 LNG Trade in Review

Global LNG Trade	LNG Exporters & Importers	LNG Re-Exports	LNG Price Change
Growth of global LNG trade	Number of new LNG importers in 2018	Re-exported volumes increased by 46% YOY in 2018	Rise in average Northeast Asian spot price from 2017 to 2018, in MMBtu
Global LNG trade reached an all-time high of 316.5 MT in 2018, setting a record for the fourth consecutive year. China provided 15.8 MT in new import demand, while new records were reached in South Korea and India, as the pair added 6.4 MT and 4.0 MT, respectively. Contractions were largest in Egypt, the UAE, and Spain (-3.7 MT, -1.4 MT, and -1.4 MT, respectively).	Bangladesh and Panama became LNG importers during 2018 after their first terminals came online. In Bangladesh, an offshore terminal began supplying the regional gas network, while in Panama an onshore terminal provides LNG for use at the market's first gas-fired power plant. While most liquefaction capacity was added in markets already exporting LNG, a floating liquefaction project came online in Cameroon, raising the number of exporters to 19.	Re-export activity rose in 2018, supported by increased activity during the first quarter of 2018 as persistently-high Asian LNG prices attracted cargoes. The start of Yamal LNG resulted in an increase in re-exports as well, as much of the plant's production is transferred from specialized ice-class LNG carriers to conventional carriers in Europe for onward sale.	While Northeast Asian prices still experienced seasonal variability in 2018, they generally increased throughout the year, reaching $10.38/MMBtu in December. After hitting a peak of $9.54/ MMBtu in September 2018, NBP began to decline in October owing to the influx of LNG and mild temperatures, and reached $8.29/MMBtu by November 2018.

[3] All counts and totals within this section include all markets that imported LNG on conventionally-sized LNG carriers and above even if they only have small-scale (<0.5 MTPA) regasification capacity, such as Jamaica and Malta. They also exclude markets that buy cargoes exclusively from domestic liquefaction plants, such as Indonesia. Refer to Chapter 10: References for a description of the categorization of small-scale versus large-scale LNG.

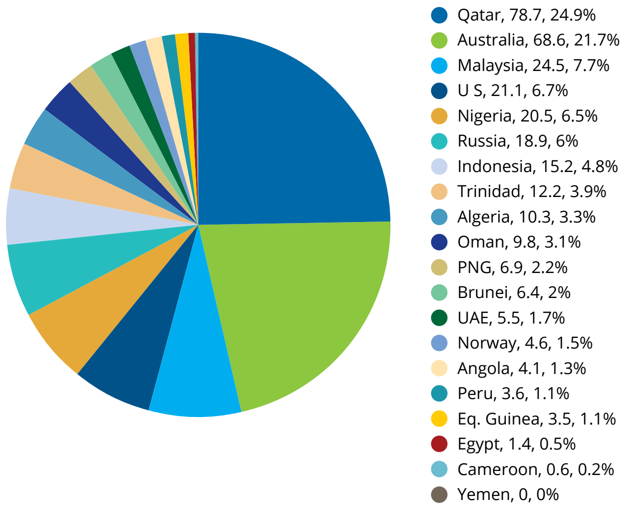
3.2 LNG EXPORTS BY MARKET

While most of liquefaction capacity added was in markets that were already exporting LNG, the 2.4 MTPA Kribi FLNG project came online during 2018, increasing the number of LNG exporting markets to 19. Additional LNG supply was available in both the Atlantic and Pacific Basins, with Australia and the United States (+12.2 MT and +8.2 MT, respectively) providing 72% of net new supply (see Figure 3.3). The other key contributor to global supply was at Yamal LNG in Russia; the first train reached commercial operations early in 2018, followed by the second train later in the year. The third train launched commissioning cargoes late in the final quarter of 2018 and was announced to start commercial production in early 2019. With consistent exports at Sakhalin-2 LNG, Yamal LNG production contributed to Russia's incremental supply growth of 7.8 MT. Performances were mixed at older projects across both basins, with total net gains in LNG supply amounting to 16.4 MT in the Atlantic Basin and 7.7 MT from the Pacific Basin. Beyond the aforementioned three leaders, the largest absolute changes YOY were from Malaysia (-2.0 MT), Qatar (+2.0 MT), and Algeria (-1.9 MT).

With exports of 78.7 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 25%), as its production remains mostly stable while exports from other markets have grown (see Figure 3.2).

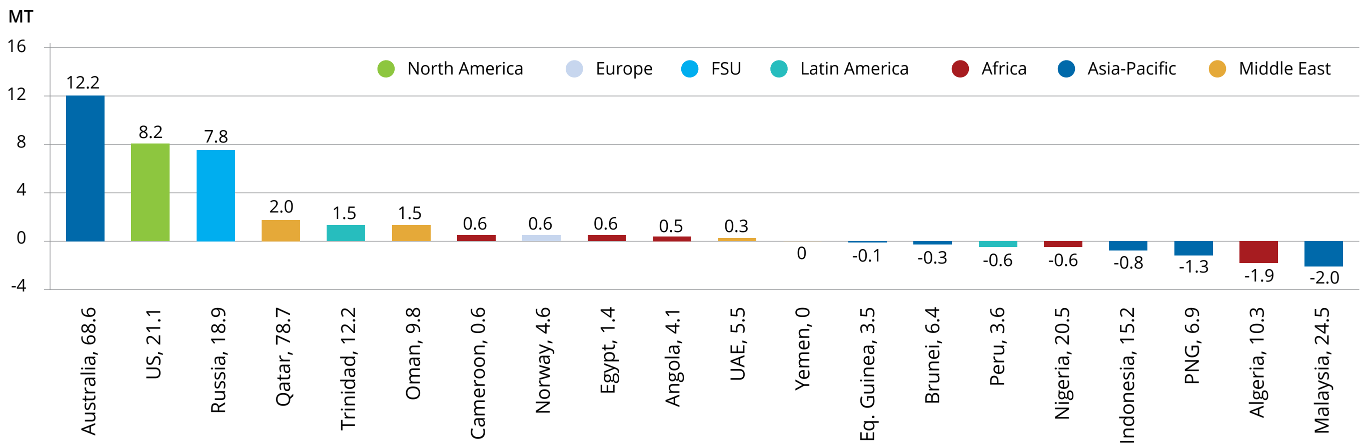
There has been a slight shake-up in the rankings of LNG exporters, with the United States jumping to fourth (21.1 MT) in 2018. Australia and Malaysia remained second and third, respectively. Australia continued to close the gap with Qatar, cutting the latter's lead to 10 MT in 2018; this could potentially be closed during 2019 given new production from Prelude FLNG and Ichthys LNG. Nigeria clung to the fifth position with 20.5 MT, but Russia is likely to surpass Nigeria and possibly even Malaysia during 2019 as production from Yamal LNG increases.

Figure 3.2. 2018 LNG Exports and Market Share by Market (in MT)



Note: Numbers in the legend represent total 2018 exports in MT, followed by market share.
Sources: IHS Markit, IGU

Figure 3.3. 2018 Incremental LNG Exports by Market Relative to 2017 (in MT)

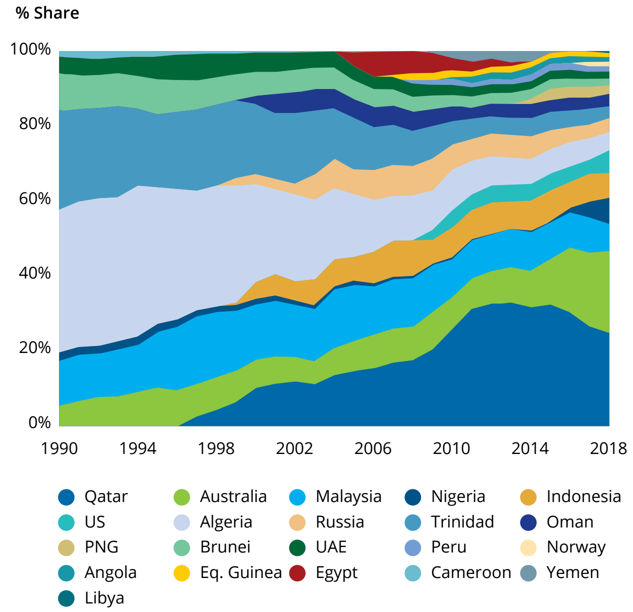


Sources: IHS Markit, IGU

Following strong LNG production during 2017, eight markets failed to match their totals from the previous year in 2018 (see Figure 3.3). Indonesian exports continued to decline owing to maturing feedstock sources, as well as more gas being required for the domestic market. In Algeria, feedstock for LNG was instead used to boost pipeline gas exports to Europe. Production also fell in Papua New Guinea, Malaysia, and Peru, where issues with midstream infrastructure caused either by natural disasters or technical issues reduced annual LNG output.

Of exporters with YOY growth, gains were limited outside of the three key growth markets. From legacy projects, increased production was apparent at Trinidad and Oman owing to better upstream performances (each one +1.5 MT YOY). Additional production due to better plant performance occurred in Norway and Angola, although the latter continues to operate below nameplate capacity. An improved gas supply balance in Egypt enabled a slow return to higher LNG exports, although production remains well below nameplate value. Cameroon began exporting LNG during 2018, with 0.6 MT of production from the 2.4 MTPA Kribi FLNG – the world's first LNG floating production storage and offloading (FPSO) unit converted from an LNG carrier. During 2019, small incremental volumes are expected to be provided by another floating liquefaction vessel that will be stationed at Bahia Blanca in Argentina, enabling seasonal LNG exports.

Figure 3.4 Share of Global LNG Exports by Market, 1990-2018



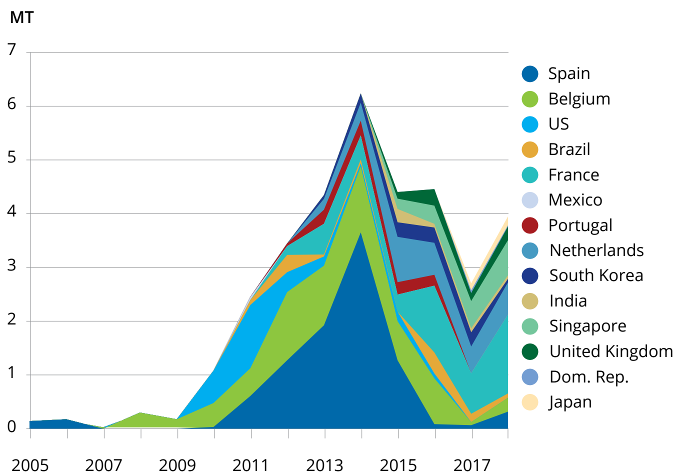
Sources: IHS Markit, IGU

3.9 MT
Re-exported LNG volumes in 2018

Re-exported trade recovered during 2018, increasing by 46% to 3.9 MT (just over 1% of global trade). The number of markets that re-exported LNG remained at 11, the same markets that re-exported cargoes during 2017. The recovery in re-exports was reflective of higher opportunity for arbitrage plays between basins during the early part of the year.

More support for re-export trade came from the start of production from Yamal LNG, as much of the production is re-loaded from specialized ice-class carriers on to conventional carriers at European terminals. Re-exports increased from all five European re-exporters – France, Belgium, the Netherlands, Spain, and the UK – accounting for 2.9 MT of total re-export trade. Changes to Spanish regulations made during 2018 may encourage a return of re-export activity from the market during 2019; previously, over 1 MT of re-exports occurred from Spain annually between 2012-2015. Beyond Europe, re-exports were strong in Singapore, rising for the third straight year to 0.7 MT as the market increases its position as an LNG hub in the Pacific Basin.

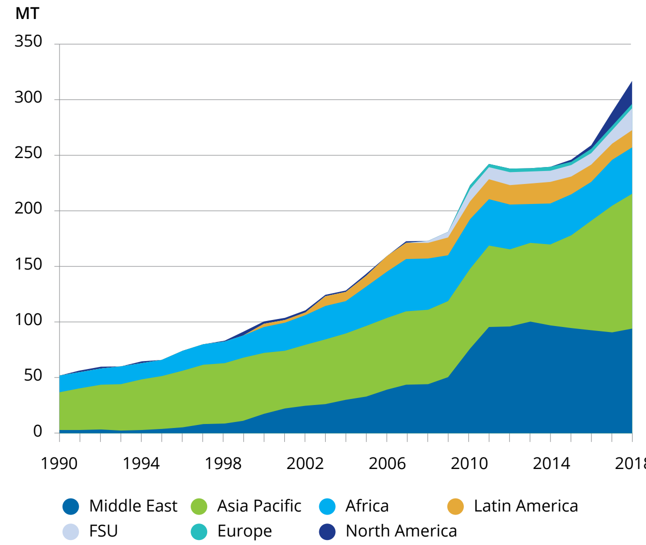
Figure 3.5: Re-exports by Market, 2005-2018



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

Given stronger production from Yamal LNG, which supported re-export trade during 2018, re-exports may increase in the near term. However, re-exports based on price arbitrage plays, which had been the strongest driver of re-exports in the past, may be challenged in the short run with an expected tighter shipping market and the materialization of an abundance of LNG supply. Seasonal or logistical re-export plays, such as is the case in Singapore or Brazil, may help underpin re-export trade to a degree.

Figure 3.6: LNG Exports by Region, 1990-2018



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

The lead in LNG production that was established by the Asia-Pacific region in 2016 was expanded upon again during 2018, with regional production rising to 121.6 MT (+7.9 MT YOY; see Figure 3.6). The Middle East remained the clear second-place exporting region owing to Qatar's industry-leading 77 MT of nameplate liquefaction capacity. The Middle East received additional support with better output at Oman LNG, although exports from the United Arab Emirates remained flat. Exports from Yemen LNG have yet to restart owing to domestic instability in the market.

LNG supply from North America was driven entirely by the United States, which benefitted from year-long production at Sabine Pass LNG T3 and T4 plus the start-up of Cove Point LNG. Commissioning volumes from Sabine Pass LNG T5 and Corpus Christi LNG T1 were also loaded during the final quarter of the year. In Latin America, exports increased for the second consecutive year (+0.9 MT) owing to increased exports from Atlantic LNG in Trinidad given better feedstock availability. Production fell at Peru LNG, which experienced issues with feedstock and loading cargoes due to multiple weather-related disruptions.

During 2019, LNG exports from the Americas are likely to be supported again by increased production from the United States given the expected start-up of trains at Corpus Christi LNG, Elba Island LNG, Freeport LNG, and Cameron LNG. Increased production from Trinidad is a possibility as well, although support from cross-border Venezuelan feedstock may have to wait until after 2019 as a deal was reached only in the second half of 2018. Somewhat surprisingly, surging domestic production in Argentina is allowing for seasonal gas exports. After the market chartered an idle LNG FPSO vessel in late 2018, the Tango FLNG project is set to export up to 0.5 MT during 2019 from the market's Bahia Blanca port.

3.3 LNG IMPORTS BY MARKET

New markets continue to play a minor role in LNG demand growth, with all new importers across 2016, 2017, and 2018 (five markets), amounting to just 1.3 MT in incremental growth in 2018 (total imports from those five markets reached just 1.8 MT). The class of 2015 importers have provided slightly more support, with Pakistan adding 2.4 MT and Poland 0.7 MT (the two combined for a total 9.1 MT of imports in 2018). However, the third new importer of 2015, Egypt, experienced the largest contraction of all LNG markets (-3.7 MT YOY), cancelling out the contributions to global trade from that group. Instead, the major Asia and Asia Pacific[4] markets again boosted LNG imports, with China and South Korea increasing their LNG take by 15.8 MT and 6.4 MT YOY, respectively.

Asia Pacific remained the largest importing region by a wide margin in 2018, although its share of global trade fell under 50% for the first time since the mid-1970s, to 48%. This is the fifth 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 continued recovery in European imports. Demand in Asia-Pacific continues to be led by Japan (83.2 MT), with South Korea (44.5 MT) reaching a new annual record for imports during 2018. Despite higher production from Australia, intra-Asia-Pacific trade decreased in 2018 given lower output from other regional producers and slower imports into Japan. Still, intra-regional trade amounted to 81.8 MT during 2018.

In Japan, imports declined modestly (-0.6 MT YOY) given lower LNG requirements from the power sector. The market remains the single-largest LNG importer, representing over 26% of total global LNG trade. South Korea, which had been the second-largest market as recently as 2016, showed strong LNG import growth for its part, rising by 6.4 MT in 2018. A cold end to the 2017-2018 winter as well as limits on the availability of coal and nuclear power capacity supported LNG imports in the market. Japanese and South Korean imports continued to be increasingly sourced from Australian projects, as well as traditionally key suppliers Qatar and Malaysia.

Asia firmed up its position as the second-largest importing region during 2018, recording the highest increase by region (+22.2 MT YOY) to reach 85.9 MT. Asia's share of global LNG trade has risen every year since China became the first importer in the region to receive LNG in 2006. The increase in Asian imports was driven by China, which surpassed its own record for incremental growth for a single market set last year by increasing LNG imports by 15.8 MT (+41% YOY). This was the third consecutive year in which China led all markets in incremental LNG import growth, and it has established itself as the clear second-largest LNG market globally. This increase in LNG imports during 2018 was reflective of the continued enforcement of environmentally-driven policies mandating coal-to-gas switching in addition to sustained economic growth in the market.

South Asia was also an important region for incremental LNG import growth. The three importers in the region added 7.1 MT of LNG imports YOY. India had the third-largest incremental growth of any market in 2018, solidifying its position as the fourth-largest LNG importer. LNG cargoes were required as demand in India's power, fertilizer, and industrial sectors rose at a rate that could not be matched by domestic gas production. In Pakistan, strong domestic demand supported LNG imports, although infrastructure bottlenecks and financial issues restricted the ability of the market to absorb even more LNG. Bangladesh received its first LNG cargo, in part to complement declining indigenous production. All three of these markets are likely to experience continued import growth during 2019. Buyers in Asia continued to source primarily from a mix of Middle Eastern and Asia Pacific suppliers (providing 79% of regional supply).

European imports expanded for the fourth consecutive year in 2018, reaching 50.0 MT (+7.3% YOY). Higher gas imports for the continent were necessitated by declines in domestic production, mainly in the Netherlands and the United Kingdom, as well as increased natural gas consumption given steady industrial sector demand. For the first three quarters of the year, pipeline imports from Russia and Algeria were prioritised in meeting this higher gas import need. However, in the final quarter of the year, European LNG imports spiked to a new record. With high charter rates for LNG carriers and low spot LNG prices in Asia, LNG flows into Northwest European gas markets rose and re-exports decreased. This was particularly the case for flexible-destination cargoes from Atlantic Basin producers, such as Russia and the United States, but not for cargoes from Qatar. Although the region's largest LNG market, Spain, contracted during 2018 due to in part to strong pipeline imports, gains were experienced in almost all other European LNG markets. The strongest increases in incremental LNG imports were markets in Northwest Europe, with Belgium (+1.4 MT), the Netherlands (+1.3 MT), and France (+0.9 MT) showing the largest growth in the region during 2018.

Despite continued increases in LNG imports, the region's relative significance in terms of its share of global trade remains below historical highs at just 15.8% in 2018 (a decrease from 2017). Europe received a higher proportion of its LNG from the former Soviet Union (FSU) and North America in 2018 than during 2017, although Africa and the Middle East remained the dominant sources of supply (a combined 75% of regional supply).

Table 3.1: LNG Trade between Basins, 2018, MT

Exporting Region / Importing Region	Africa	Asia-Pacific	Europe	Former Soviet Union	Latin America	Middle East	North America	Reexports Received	Reexports Loaded	Total
Africa	0.3		0.4	0.2	0.1	1.0	0.1	0.1		**2.3**
Asia	10.5	39.4	0.4	1.6	0.9	28.1	3.6	1.4	0.1	**85.9**
Asia-Pacific	4.6	81.8	0.2	11.4	2.6	44.7	7.5	1.4	0.9	**153.3**
Europe	20.5		3.1	4.9	4.5	16.9	2.7	0.4	2.9	**50.0**
Latin America	1.2		0.2	0.3	3.8	1.1	2.5	0.2	0.1	**10.6**
Middle East	2.3	0.1	0.2	0.3	0.8	2.2	1.1	0.3		**7.4**
North America	1.1	0.2	0.1	0.1	3.2		3.6	0.1		**7.1**
Total	**40.6**	**121.6**	**4.6**	**18.9**	**15.8**	**94.0**	**21.1**	**3.9**	**-3.9**	**316.5**

Sources: IHS Markit, EIA, IGU

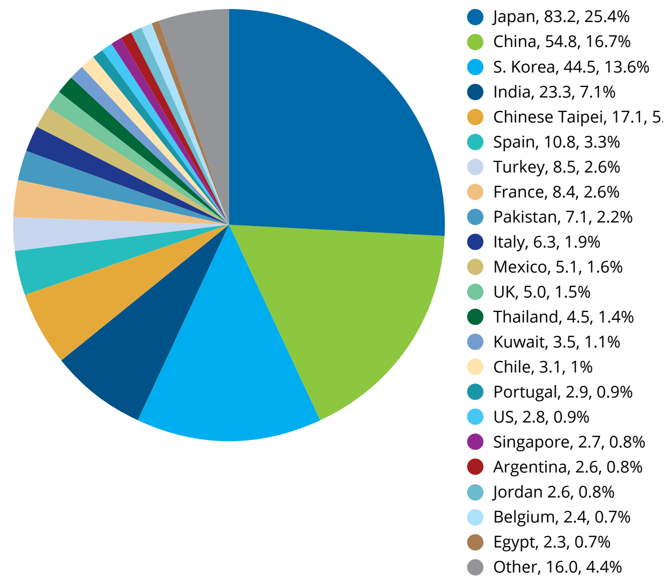
[4] In this chapter, the Asia region includes China, India, Pakistan, and Bangladesh while the remainder of markets on the Asian continent are included in the Asia-Pacific region. Please refer to Chapter 10: References for the exact definitions of each region.

Although the large natural gas markets of the United States Lower 48 and Canada continue to take small volumes of LNG, minor growth in North American imports was supported by recovery in Puerto Rico (US) following Hurricane Maria in 2017 and delays in additional pipeline capacity in Mexico, with the region as a whole rising by 0.6 MT YOY.

In Latin America, Brazil LNG imports were supported by short-term power sector demand necessitating LNG imports during the second half of the year. However, total Latin American imports were essentially flat (+0.01 MT YOY) as annual LNG imports into Argentina declined for the fifth consecutive year to just 2.6 MT (-0.6 MT). Domestic gas production has responded positively to policy changes and more investment in the market in recent years, leading to higher output from its vast unconventional resource base. Still, midstream bottlenecks prevent domestic resources from fully meeting winter gas demand in population centres along the coast, thus LNG imports remain consistent during periods of peak demand. However, surging gas production has enabled natural gas exports during low-demand periods, reducing LNG import requirements in neighbouring Chile. In fact, natural gas is set to be exported as LNG from Argentina via Tango FLNG during 2019.

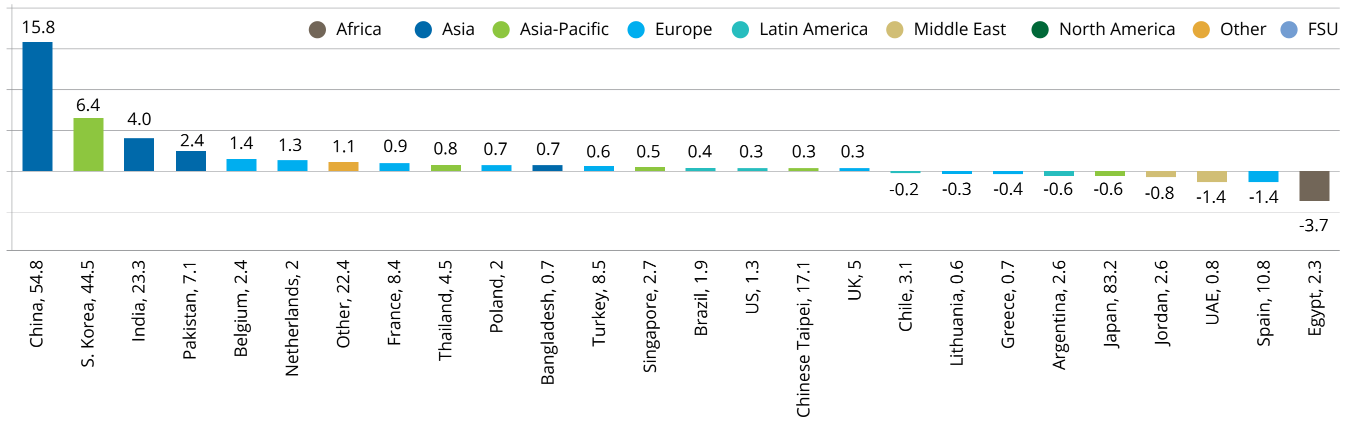
Because Egypt is the only LNG-importing market in Africa, the region had the largest decline (-3.7 MT) as the market's improved domestic production removed the need for LNG imports. Beyond Africa, the only other region to experience declining LNG imports during 2018 was the Middle East, which fell by 2.2 MT to a total of 7.4 MT for 2018. The decline in LNG imports in the region was most apparent in the UAE and in Jordan (-1.4 MT and -0.8 MT, respectively). In the former, stronger domestic production helped replace imported LNG. In the latter, a reduced need for LNG to be imported via the Aqaba terminal for export via pipeline to Egypt was responsible for the decline. Despite the Middle East being home to the world's largest LNG exporter, Qatar, the region received just 2.2 MT (30%) of its total imports from the Middle East during 2018.

Figure 3.7. 2018 LNG Imports and Market Share by Market (in MT)



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

Figure 3.8: Incremental 2018 LNG Imports by Market & Incremental Change Relative to 2017 (in MT)



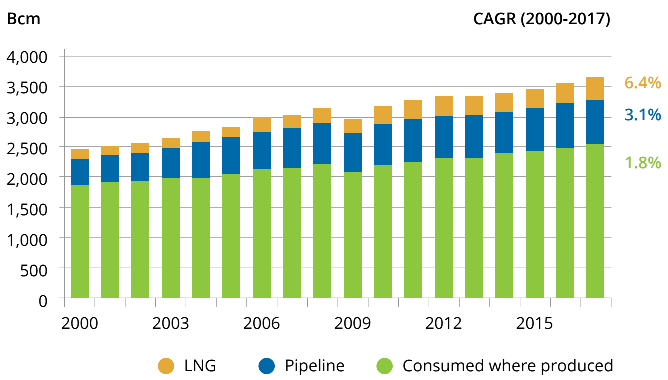
Note: "Other" includes markets with incremental imports of less than ±0.2 MT: Malaysia, Italy, Mexico, Kuwait, Portugal, the Dominican Republic, Malta, Panama, Israel, Canada, Jamaica, and Colombia.
Sources: IHS Markit, IGU

Although LNG has had a higher annual rate of growth over the past 17 years than either global production for indigenous consumption or international pipeline exports, much of the impressive growth occurred in the first decade, with growth slowing during 2010-15 as global markets worked to absorb the rapid expansion of liquefaction capacity from the end of the 2000s. Growth in LNG consumption as a percentage of global trade began to rise briskly again in 2016, driven first by the liquefaction capacity buildout in Australia, and then recent capacity additions across the United States and Russia (see Figure 3.9). In 2017, LNG's share of global gas trade jumped by 0.8 percentage points, setting a new record of 10.7% of global consumption (surpassing the previous record of 10% in 2011). Pipeline's share also increased, to 20.2%, showing that natural gas import reliance is growing. Pipeline trade into Europe was a key factor, with both Russian gas exports to Europe hitting a record during the year, as well as rising flows from the United States into Mexico and FSU markets into China.

Huelva LNG Terminal - Courtesy of Enagas

+ 6.4% p.a.
Average yearly growth rate
of LNG demand since 2000

Figure 3.9: Global Gas Trade, 2000-2017



Note: CAGR = Compound Annual Growth Rate; Annual data through 2017 is the most recent available.
Sources: IHS Markit, BP Statistical Review of World Energy

LNG trade has continued to develop for reasons that vary by market and region. In Japan, South Korea, and Chinese Taipei (JKT), LNG imports are driven by geographic remoteness and gas resource scarcity. Additionally, uncertainties regarding nuclear power have continued to support LNG imports. Restrictions on coal-fired generation to improve air quality in the region are likely to support LNG usage through the long term in these markets. Unlike some other importing regions, these markets find themselves without prospects for increased domestic gas production and/or major cross-border pipeline connections.

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 at two traditional producers, the Netherlands and the United Kingdom. Furthermore, in a multitude of markets, there has been an increase in LNG imports to complement local gas production to keep pace with demand growth; including in Bangladesh, Thailand, and China.

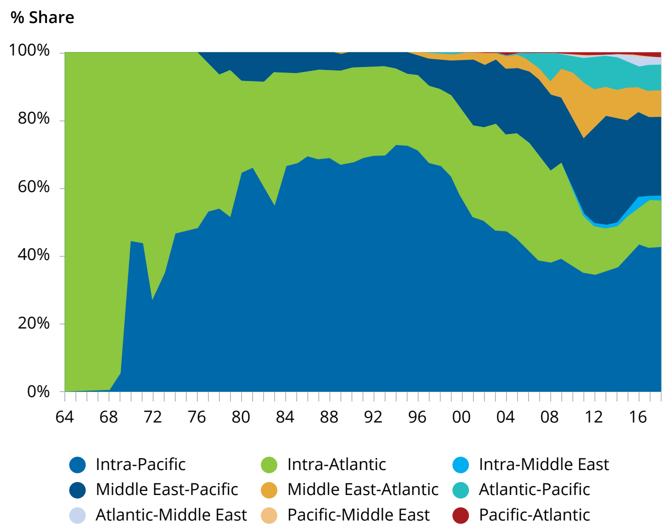
LNG continues to be used to increase gas supply security even in markets with ample pipeline connections. European importers such as Italy, Portugal, and Turkey use LNG to diversify their import mix and to maintain access to gas in the case of inadequate pipeline flows. Many markets such as Kuwait and Argentina use seasonal LNG imports to meet summer or winter demand peaks for cooling and heating. Markets with high renewables penetration in their power generation 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 markets across Latin American, such as Brazil, Colombia, and Panama.

During the past decade, the fortunes of domestic gas production in several markets have, and will continue to affect their outlooks as importers. The most pronounced shift was the shale revolution in the United States, which allowed the market 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, the possibility of expanding unconventional gas production has begun to change LNG import dynamics. This has been the case in Argentina, where expanding production has altered LNG import patterns not only in that market, but the region as well. The development of conventional gas resources is also playing a key factor in LNG imports, reducing LNG import requirements in Egypt.

3.4 LNG INTERREGIONAL TRADE

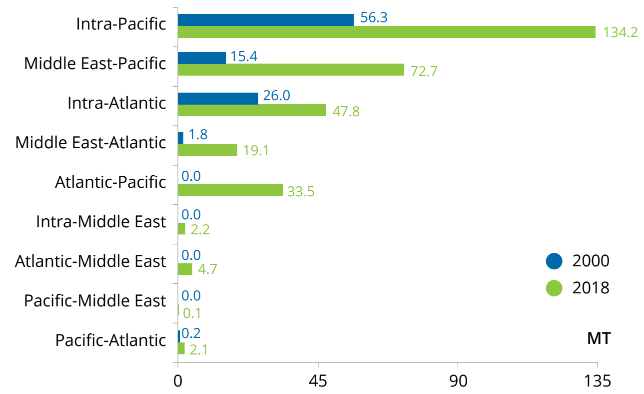
The largest global LNG trade flow route continues to be intra-Pacific trade (see Figure 3.10), a trend that is unlikely to change in the near term given high demand growth in China, Southeast Asia, and South Asia, and increasing supply from Australia. Trade between the Middle East and Pacific was the second-highest by volume owing to Qatar's role in supplying Japan, South Korea, and China. Stronger production in the Atlantic Basin during the year resulted in higher intra-basin flows as well as increased deliveries to the Pacific Basin. Intra-Atlantic trade remained the third largest route by volume, although Atlantic-Pacific trade grew by 11.6 MT during 2018, becoming the fourth largest route.

Figure 3.10: Inter-Basin Trade Flows 1964-2018



Sources: IHS Markit, IGU

Figure 3.11: Inter-Basin Trade, 2000 v. 2018



Sources: IHS Markit, IGU

Pacific Basin LNG has continued to remain mostly within its own basin, with Pacific-Middle East and Pacific-Atlantic flows totalling just 2.2 MT in 2018, compared to 134.2 MT of Intra-Pacific trade. Moreover, the Pacific Basin attracted more LNG from the Atlantic Basin, largely the result of higher LNG flows from the United States to Asia via the Panama Canal. Flows into the Middle East remain relatively small, with other Middle East and Atlantic Basin sources providing nearly all of those markets' imports.

DSLNG Tanker - Courtesy of KOGAS

Table 3.2: LNG Trade Volumes between Markets, 2018 (in MT)

	Algeria	Angola	Australia	Brunei	Cameroon	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	2018 Exports	2017 Net Imports	2016 Net Imports	2015 Net Imports	2014 Net Imports	2013 Net Imports	2012 Net Imports
Egypt	-	-	-	-	-	-	0.06	-	-	0.20	0.44	-	-	-	1.02	0.20	0.07	-	0.13	-	0.15	-	2.26	5.97	7.32	2.68	-	-	-
Africa	-	-	-	-	-	-	0.06	-	-	0.20	0.44	-	-	-	1.02	0.20	0.07	-	0.13	-	0.15	-	2.26	5.97	7.32	2.68	-	-	-
Bangladesh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.70	-	-	-	-	-	-	-	0.70	-	-	-	-	-	-
China	0.07	0.56	24.06	0.21	0.17	0.20	0.70	4.85	6.01	1.09	0.26	0.38	2.31	0.07	9.19	1.20	0.38	-	2.26	-	0.79	-	54.75	38.97	27.01	19.69	19.81	18.51	14.77
India	0.23	1.72	1.49	-	0.27	0.14	0.95	-	0.27	3.04	0.07	1.07	-	-	11.61	0.35	0.38	0.32	1.04	-	0.39	(0.07)	23.26	19.30	18.38	15.79	14.29	13.24	13.99
Pakistan	0.14	0.07	0.06	-	-	-	0.32	0.12	0.06	0.89	0.12	0.06	-	-	4.59	0.07	0.06	0.13	0.25	-	0.20	-	7.15	4.74	2.91	0.95	-	-	-
Asia	0.43	2.35	25.61	0.21	0.44	0.34	1.96	4.97	6.34	5.02	0.44	1.51	2.31	0.07	26.09	1.62	0.82	0.45	3.56	-	1.38	(0.07)	85.86	63.01	48.30	36.43	34.11	31.74	28.76
Japan	-	0.20	29.00	4.20	-	0.13	0.12	5.05	11.30	1.41	0.06	3.05	3.18	0.56	9.98	7.00	0.12	4.90	2.48	-	0.63	(0.17)	83.21	83.84	82.78	85.34	88.69	87.75	87.24
Malaysia	-	-	0.90	0.39	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	1.29	1.42	1.08	1.53	1.55	1.46	-
Singapore	-	0.14	2.17	-	-	-	0.28	0.13	-	-	-	-	0.08	-	0.43	-	0.07	-	-	-	0.07	(0.65)	2.71	2.24	2.08	2.02	1.88	0.92	-
South Korea	-	0.27	8.15	0.83	-	0.19	0.06	3.52	3.60	0.49	0.06	4.28	0.07	0.96	14.45	2.06	0.18	-	4.74	-	0.64	(0.06)	44.50	38.05	33.87	33.22	37.81	40.69	36.78
Chinese Taipei	-	0.06	2.59	0.76	0.06	-	-	1.22	2.71	0.18	0.06	0.31	1.15	0.06	5.03	2.32	0.24	0.06	0.25	-	0.07	-	17.14	16.84	15.19	14.58	13.59	12.84	12.78
Thailand	-	-	0.07	0.06	-	0.07	-	0.19	0.53	0.92	-	0.07	-	-	2.02	0.07	0.39	0.06	-	-	-	-	4.45	3.70	2.90	2.62	1.28	1.41	0.97
Asia-Pacific	-	0.67	42.86	6.24	0.06	0.40	0.47	10.11	18.14	3.00	0.19	7.71	4.48	1.58	31.91	11.45	1.00	5.03	7.47	-	1.40	(0.88)	153.29	146.09	137.89	139.32	144.80	145.06	137.77
Belgium	-	0.07	-	-	-	-	-	-	-	-	0.07	-	-	-	1.89	0.59	-	-	-	-	0.03	(0.26)	2.40	1.03	1.00	1.90	0.81	1.18	1.91
France	3.16	0.07	-	-	-	0.26	-	-	-	2.76	1.13	-	-	0.20	0.86	1.10	0.06	-	0.31	-	-	(1.47)	8.43	7.58	5.57	4.57	4.72	5.65	7.48
Greece	0.60	-	-	-	-	-	-	-	-	-	-	-	-	-	0.06	-	-	-	0.07	-	-	-	0.73	1.11	0.56	0.42	0.40	0.42	1.07
Italy	0.65	0.07	-	-	0.06	0.10	0.14	-	-	0.06	0.13	-	-	-	4.71	-	-	-	0.34	-	-	-	6.26	6.13	4.43	4.08	3.02	3.96	5.23
Lithuania	-	-	-	-	-	-	-	-	-	-	0.60	-	-	-	-	-	-	-	-	-	-	-	0.60	0.91	1.07	0.32	0.10	-	-
Malta	-	-	-	-	-	-	0.06	-	-	0.08	-	-	-	0.06	-	-	0.18	-	0.07	-	-	-	0.45	0.26	-	-	-	-	-
Netherlands	0.11	0.15	-	-	-	-	-	-	-	-	0.31	-	-	0.24	0.28	1.25	-	-	0.24	-	-	(0.60)	1.97	0.69	0.39	0.63	0.43	0.49	0.61
Poland	-	-	-	-	-	-	-	-	-	-	0.25	-	-	-	1.68	-	-	-	0.07	-	-	-	2.00	1.26	0.81	0.08	-		
Portugal	0.10	-	-	-	-	-	-	-	-	1.82	-	-	-	-	0.73	-	-	-	0.26	-	0.03	-	2.94	2.78	1.34	1.22	0.98	1.39	1.66
Spain	1.12	0.06	-	-	0.06	-	-	-	-	3.11	0.44	-	-	1.29	2.48	0.66	1.61	-	0.20	-	0.11	(0.32)	10.82	12.25	10.11	8.84	8.16	9.74	14.22
Turkey	3.54	0.07	-	-	-	0.15	0.06	-	-	1.64	0.06	-	-	-	2.15	-	0.36	-	0.26	-	0.20	-	8.48	7.92	5.56	5.60	5.32	4.41	5.68
United Kingdom	0.17	-	-	-	-	0.12	0.06	-	-	0.06	0.08	-	-	0.06	2.11	1.25	0.42	-	0.88	-	-	(0.25)	4.95	4.70	7.20	9.86	8.36	6.99	10.36
Europe	9.45	0.50	-	-	0.12	0.62	0.32	-	-	9.53	3.06	-	-	1.85	16.94	4.85	2.62	-	2.70	-	0.38	(2.89)	50.03	46.62	38.03	37.52	32.31	34.24	48.22
Argentina	0.06	-	-	-	-	-	0.06	-	-	0.38	-	-	-	-	1.05	-	0.42	-	0.51	-	0.08	-	2.56	3.16	3.59	4.19	4.68	4.75	3.82
Brazil	-	0.07	-	-	-	-	-	-	-	0.20	0.18	-	-	-	0.06	0.28	0.35	-	0.74	-	0.15	(0.08)	1.95	1.54	1.28	5.00	5.71	4.26	2.52
Chile	-	-	-	-	-	-	0.47	-	-	-	-	-	-	-	-	-	1.84	-	0.82	-	-	-	3.13	3.37	3.27	3.00	2.78	2.86	3.03
Colombia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.13	-	0.09	-	-	-	0.22	0.03	0.06	-	-	-	-
Dominican Republic	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.92	-	0.16	-	-	(0.02)	1.06	1.04	0.84	0.95	0.92	1.09	0.96
Jamaica	-	-	-	-	-	-	-	-	-	-	0.01	-	-	-	-	-	0.17	-	0.06	-	-	-	0.23	0.17	0.06	-	-	-	-
Panama	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.06	-	-	0.09	-	-	-	0.16						
Puerto Rico	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-	1.28	0.96	1.30	1.13	1.24	1.21	0.97
Latin America	0.06	0.07	-	-	-	-	0.53	-	-	0.58	0.19	-	-	-	1.11	0.34	3.83	-	2.47	-	0.22	(0.10)	9.32	9.31	9.10	13.14	14.09	12.96	10.33
Israel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.47	-	0.06	-	-	-	0.53	0.46	0.28	0.13	0.12	0.41	-
Jordan	0.07	-	-	-	-	-	0.07	-	-	0.62	0.12	0.08	-	-	0.19	0.28	0.23	-	0.83	-	0.06	-	2.55	3.36	3.25	1.90	-	-	-
Kuwait	-	0.49	-	-	-	0.06	0.13	-	-	0.41	0.12	0.48	-	-	1.43	0.06	0.06	-	0.16	-	0.06	-	3.48	3.55	3.62	3.07	2.73	1.64	2.11
United Arab Emirates	0.28	0.07	0.14	-	-	-	-	-	-	0.07	-	-	-	-	-	-	-	-	0.07	-	0.20	-	0.83	2.21	3.17	2.40	1.39	1.25	1.20
Middle East	0.36	0.56	0.14	-	-	0.06	0.20	-	-	1.10	0.25	0.56	-	-	1.62	0.34	0.75	-	1.13	-	0.32	-	7.39	9.58	10.33	7.51	4.24	3.30	3.31
Canada	-	-	-	-	-	-	-	-	-	-	0.06	-	-	-	-	0.07	0.32	-	-	-	-	-	0.45	0.32	0.24	0.47	0.42	0.75	1.28
Mexico	-	-	-	-	-	-	-	0.13	-	1.06	-	-	0.07	0.06	-	-	0.20	-	3.59	-	-	-	5.10	4.94	4.14	5.07	6.87	5.94	3.55
United States	-	-	-	-	-	-	-	-	-	0.06	-	-	-	-	-	0.06	2.62	-	-	-	0.09	-	2.84	2.53	2.98	2.86	2.42	3.04	4.24
North America	-	-	-	-	-	-	-	0.13	-	1.12	0.06	-	0.07	0.06	-	0.14	3.13	-	3.59	-	0.09	-	8.39	7.79	7.36	8.40	9.71	9.74	9.06
2018 Exports	10.30	4.14	68.61	6.45	0.61	1.43	3.54	15.21	24.49	20.55	4.63	9.79	6.86	3.56	78.69	18.93	12.23	5.48	21.05	-	3.95	(3.95)	316.54						
2017 Exports	12.17	3.67	56.37	6.74	-	0.86	3.60	16.02	26.49	21.15	4.04	8.33	4.14	8.13	76.71	11.11	10.76	5.20	12.90	-	2.70	(2.70)		288.37					
2016 Exports	11.62	0.77	43.79	6.23	-	0.52	3.28	16.28	24.79	18.14	4.40	8.11	4.04	7.68	78.68	10.75	10.59	5.77	2.89	-	4.46	(4.46)			258.33				
2015 Exports	12.13	-	29.25	6.45	-	-	3.76	15.94	24.76	20.29	4.30	7.66	3.65	7.10	79.17	10.81	12.27	5.61	0.32	1.53	4.57	(4.57)				245.00			
2014 Exports	12.53	0.34	23.25	6.17	-	0.33	3.70	15.88	24.90	19.31	3.70	7.86	4.33	3.49	75.90	10.56	14.31	5.78	0.25	6.66	6.23	(6.23)					239.26		
2013 Exports	10.81	0.33	22.18	6.93	-	2.79	3.87	17.00	24.68	16.70	2.98	8.64	4.26	-	78.01	10.75	14.52	5.41	-	7.20	4.59	(4.59)						237.05	
2012 Exports	10.97	-	20.78	6.85	-	5.08	3.75	18.12	23.11	19.95	3.41	8.08	3.89	-	77.32	10.92	14.40	5.53	0.17	5.13	3.45	(3.45)							237.46

Note: Indonesia, Malaysia, India, France, and the UAE conducted domestic LNG trade in 2012-2018. These volumes are not included above as they do not reflect international trade between markets.
Sources: IHS Markit, IGU

3.5 SHORT, MEDIUM AND LONG-TERM TRADE[5]

The LNG market has grown increasingly complex over the past decade, as a greater number of participants utilize a broader variety of trading strategies. While cargoes were historically mainly delivered under long-term fixed destination contracts, a growing portion of LNG is being sold under shorter contracts or on the spot market.

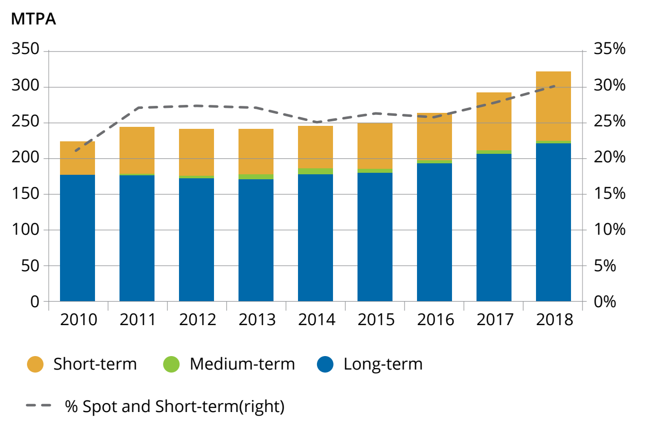
99.0 MT
Non-long-term trade in 2018;
31% of total gross trade

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. Non-long-term trade surged in 2011, owing to shocks like those that resulted from the Fukushima disaster and the growth in production of shale gas in the United States, but then stagnated through 2016 as new LNG supply came mostly from long-term contracted projects. Since then, the volume of LNG traded without a long-term contract has increased significantly, growing by 19% YOY in 2017 and by 18% YOY in 2018. This recent growth is partially caused by the ramp-up of new flexibly-contracted liquefaction projects in the Atlantic Basin, such as those in the United States and Russia. The share of the LNG market traded without a long-term contract has now reached 31% – roughly 50% higher than in 2008. 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 2018, 30 markets (including re-exporters) exported spot volumes to 35 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.
- Sudden changes in supply or demand dynamics such as the Fukushima disaster in Japan or replacing pipeline supply in Jordan.
- The decline in competitiveness of LNG in interfuel competition such as coal in the power sector (chiefly in Europe) and shale gas (North America) that has freed up volumes to be re-directed elsewhere.
- Periods of large disparity between prices in different basins such as that 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 markets to enter the LNG import market.
- The large growth in the LNG fleet, especially vessels ordered without a long-term charter, which has at times allowed for low-cost inter-basin deliveries.

Short-term trade – defined here as all volumes traded either on the spot market or under agreements of less than two years – makes up the vast majority (97%) of cargoes traded without a long-term contract, with the remainder sold under medium-term deals. In 2018, short-term trade reached 96 MT, or 29.9% of total gross traded LNG (including re-exports). As in 2017, the growth in short-term trade was supported by new liquefaction project start-ups in the Atlantic Basin. Many of the projects in the Atlantic Basin that have come online in the past two years – such as Sabine Pass LNG in the US and Yamal LNG in Russia – have destination-flexible contracts with traders or aggregator companies that have large LNG portfolios. This contrasts with the marketing structure of projects that started up in the Pacific Basin between 2014 and 2016, which were largely contracted under long-term deals directly with end-users.

Figure 3.12: Short, Medium and Long-Term Trade, 2010-2018

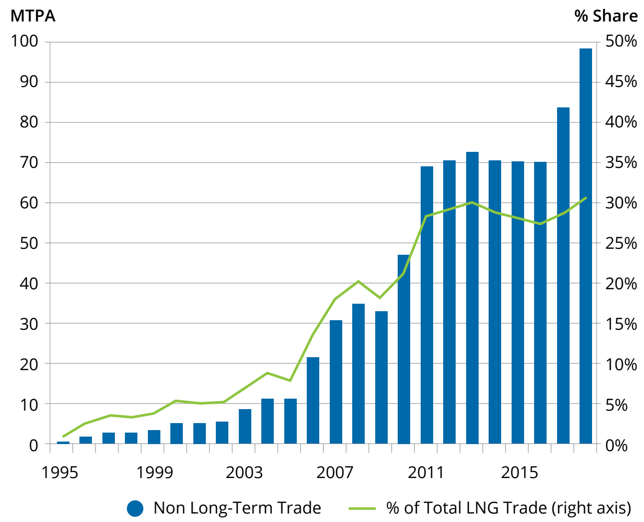


Sources: IHS Markit, IGU

[5] As defined in Chapter 10.
[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 categorized under the shortest duration of any part of the trade (e.g., volumes procured from the spot market and then delivered under a medium- or long-term portfolio contract would be considered spot).

Volumes traded under medium-term contracts (between 2 and <5 years) remain a comparatively small portion of all non-long-term trade. True medium-term deliveries – those cargoes both procured and delivered under a medium-term contract – declined for the fourth year in a row in 2018, falling from 7.1 MT at peak in 2014 to 3.0 MT in 2018. This is not necessarily a sign that medium-term contracts are falling out of favour – in fact, the volume of medium-term LNG contracted for delivery in 2018 increased by 26% YOY in 2018. The reason for the apparent decline in medium-term trade is that many traditional trader companies that were formerly active only in the spot market have begun to sign medium-term contracts as a seller, though they continue to source spot cargoes to fulfil them. Thus, medium-term contracts are being filled increasingly with short-term volumes. Medium term contracts offer markets 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.

Figure 3.13: Non Long-Term Volumes, 1995-2018



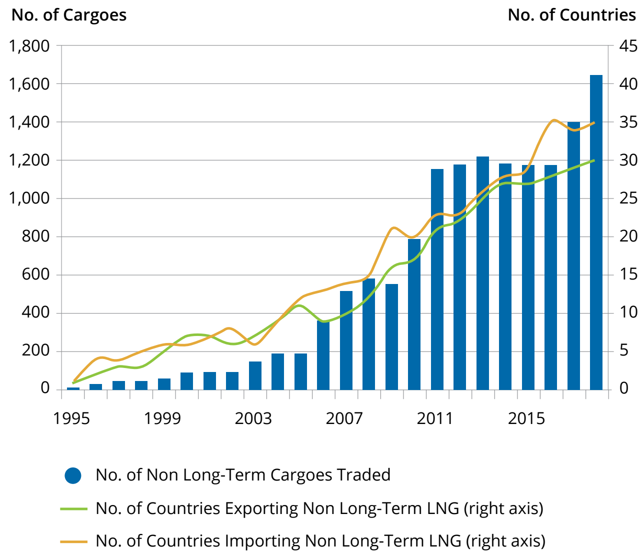
Sources: IHS Markit, IGU

Total non-long-term LNG trade (all volumes traded under contracts of less than 5 years or on the spot market) reached 99.0 MT in 2018, an increase of 14.5 MT relative to 2017. Non-long-term trade accounted for an all-time high 31% of total gross LNG trade – a 2% increase in share from 2017. With the build-up in long-term contracted Australian capacity set to come to an end in 2019 as the final few projects come online, the share of non-long-term LNG is likely to continue to increase in the near-term, particularly as the build-out in flexibly-contracted Atlantic Basin capacity is still in full swing.

As with total gross LNG trade, the largest increase in non-long-term imports came from China. The market's 41% YOY growth in LNG imports pulled heavily from the spot- and short-term market, as long-term contracts increased by only 9% YOY; non-long-term Chinese imports grew by 10 MT YOY. In early 2018, many Chinese buyers continued to search for additional short-term volumes to meet the growth spurred by 2017's anti-pollution measures, and heightened buying activity continued into the summer and fall months as buyers sought to fill storage to avoid another tight winter market. As in the previous year, South Korea continued to rely on the spot market to offset continued nuclear outages, with non-long-term imports rising by 47% YOY in 2018.

The largest decline in non-long-term imports was in Japan. In 2018, returning nuclear plants let LNG demand start to ease off the peak levels reached in the mid-2010s, causing total Japanese LNG imports to fall by 0.6 MT. Meanwhile, several new contracts between Australian LNG plants and Japanese buyers continued to ramp-up during the year, causing non-long-term imports to fall at a much faster rate (-4 MT YOY). Japan's decline was followed closely by Egypt, where non-long-term imports fell by 3.7 MT. The market had relied exclusively on short- and medium-term contracts to fill its temporary LNG demand spike, and new domestic gas production has all but eliminated the need for LNG, thus causing Egyptian buyers to pull back from the short-term market.

Figure 3.14: Non Long-Term Cargo Market Development, 1995-2018



Sources: IHS Markit, IGU

As with importers, the largest growth in non-long-term supply also came from the market with the largest total growth in exports – Australia (+6.4 MT YOY). While exports from Australian markets are primarily sent to long-term customers, several plants that ramped-up supply in 2018 were contracted to large aggregator companies that sell into a diverse portfolio of end-markets, both on a contracted and spot basis. Furthermore, the strong demand increase in China led many Australian projects to divert cargoes there rather than other Pacific markets. New Atlantic Basin suppliers also had significant growth in non-long-term supply in 2018, owing to flexible-destination contracts with aggregators, especially from Yamal LNG (Russia) and Sabine Pass LNG (the US). Russian deliveries outside of long-term contracts grew by 5.7 MT in 2018, followed by an increase of 3.5 MT from the US.

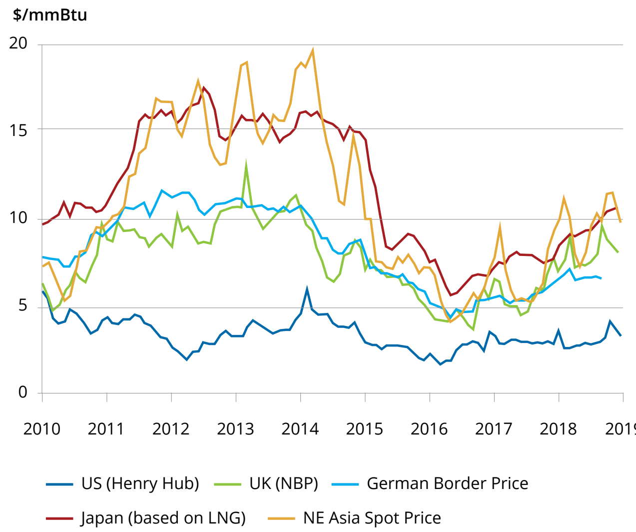
Many of the markets with declines in non-long-term supply had an outage-induced decline in total exports, including Malaysia (-2.6 MT of non-long-term deliveries) and Papua New Guinea (-1.3 MT). While total exports also declined in Nigeria (-0.6 MT of total deliveries), non-long-term exports fell more quickly as the ramp-up at Australian and new Atlantic Basin projects pushed more cargoes to be directed to their original contracted markets, particularly in Europe. As a result, non-long-term Nigerian deliveries fell by -2.1 MT.

3.6 LNG PRICING OVERVIEW

Most LNG-related prices around the world followed an upward trend in 2018, influenced by rising oil prices and strong LNG demand in Asia. Several price markers experienced some volatility in the spring and summer months, but a cold winter at the start of the year and active spot buying from China kept prices generally elevated; although Northeast Asian spot prices fell from an average $9.88/MMBtu in January 2018 to a low of $7.20/MMBtu in May 2018, this was 36% higher than their level in May 2017. While this resurgence is notable, spot prices showed some signs of weakness toward the end of 2018, as a thus far mild winter in Asia and Europe, coupled with the continued ramp-up of new supply, started to place downward pressure on spot prices, with average Northeast Asian spot prices falling by 18% between November 2018 and January 2019, landing at $9.36/MMBtu. European spot prices climbed for most of the year, though a large influx of LNG in the fourth quarter of the year began to place some downward pressure on market prices like the UK's NBP, compounded by the fall in oil prices. After hitting a peak of $9.54/MMBtu in September 2018 – over 50% higher than its level in the previous year – NBP began to decline in October and had reached $7.44/MMBtu by January 2018. As new liquefaction capacity is added in 2019, prices could fall further, particularly during traditional seasonal lulls in demand in the spring and summer months.

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 make use of gas hub-based or oil-linked pricing, and often use 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. The delivered costs of US LNG provide 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.

Figure 3.15: Monthly Average Regional Gas Prices, 2010 – January 2019



Sources: IHS Markit, Cedigaz, US Department of Energy (DOE)

Hazira Regas Terminal - Courtesy of Shell

Courtesy of Shell

As a large portion of contracts are still at least partially indexed to the price of oil, trends in the oil market are crucial indicators for LNG. 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 caused a turnaround. From an average of over $100 per barrel (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 a peak of $81/bbl in September 2018. This was short-lived, however, with Brent subsequently dropping to an average of $62/bbl in the fourth quarter of the year. Given that most oil-indexed contracts have a three- to six-month time lag against the oil price, Asian term import prices followed the rise in oil prices throughout most of 2018. The average contracted Japanese import price rose from $8.36/MMBtu in January 2018 to a high of $10.70/MMBtu in December, though this will likely fall once delayed contract linkages catch up to the drop in oil prices.

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. While buyer contracting activity from the US waned between 2014 and 2016 when oil prices were low, their increase over the past two years has led to a resurgence in interest in US volumes.

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 other primarily oil-indexed 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, though its oscillations are typically more muted than those of Japanese LNG contracted prices, owing to the influence of European hub prices. While German prices followed the slow rise in oil prices in 2017, climbing from $5.51/MMBtu in January 2017 to $6.28/MMBtu by December, prices stagnated in 2018. Prices varied by only $0.75/MMBtu in the months between January and November 2018, when German prices reached an average $6.93/MMBtu.

Spot prices in Europe typically show more variability than their long-term contracted counterparts. While LNG market dynamics and weather fundamentals caused European prices to vary significantly between seasons in 2017, prices rose steadily throughout most of 2018. NBP started the year at $6.97/MMBtu and climbed to a peak of $9.54/MMBtu in September 2018 – over 50% higher than its level in the previous year. However, a large influx of LNG in the fourth quarter of the year began to place some downward pressure on prices, and NBP fell to $7.44/MMBtu by December 2018. If near-term LNG imports into the European continent continue to reach the levels that they did in the last quarter of 2018, it may put downward pressure on the UK NBP in the coming years, though other market factors linked to supply and demand will also play an important role in prices.

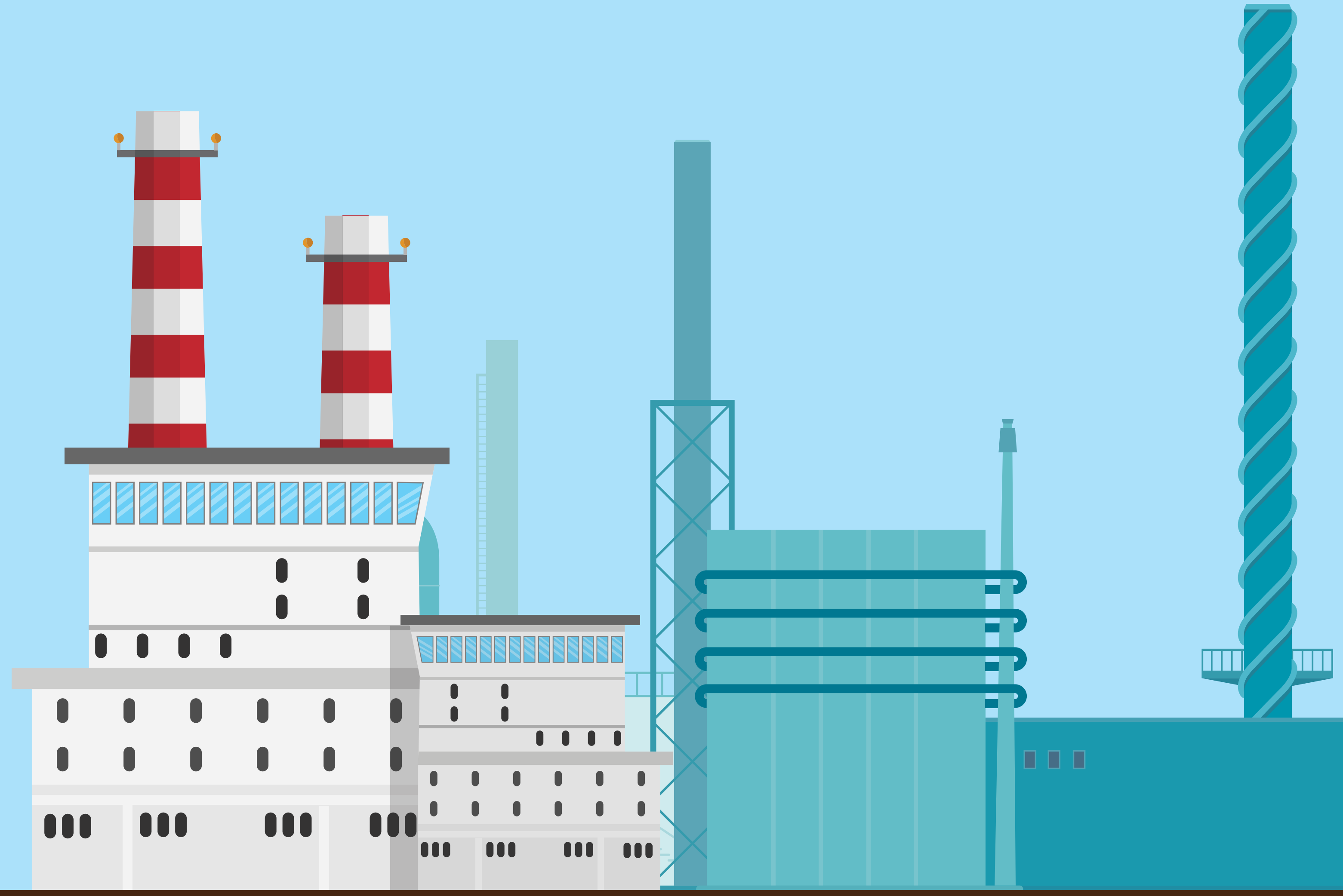
Differentials between LNG prices around the world narrowed significantly after the drop in oil prices in 2014, though recent trends have begun to widen potential arbitrages again. Although the differential between Asian and European spot prices became slightly negative once again during the summer as it had in the previous two years (with northeast Asia spot prices at an average $0.21/MMBtu discount to NBP in May 2018), it had widened substantially by the end of the year, with Asian prices at a $3.19/MMBtu premium to NBP in November. However, as both sets of prices fell going into winter, the differential had narrowed to just $1.92/MMBtu by January 2019. The differential between NBP and Henry Hub stayed relatively high throughout 2018, rising from a low of $3.25/MMBtu in January 2018 to $6.59/MMBtu by September, though the drop in NBP toward the end of the year brought the differential back down to $4.19/MMBtu by January 2019.

Gas price movements in North America are driven more by overall gas supply-demand market fundamentals than by changes in the oil price. After briefly dropping at the beginning of the year as the market left the peak winter months, Henry Hub prices climbed steadily through 2018, rising from $2.66/MMBtu in February 2018 to $4.06/MMBtu by November – the first time Henry Hub prices have averaged over $4/MMBtu for a month since late 2014. The spike in prices toward the end of the year can be partially attributed to an early start to winter in the US, with particularly cold weather in November. These pressures had begun to ease by January, with Henry Hub falling back to $3.25/MMBtu. 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.

4.
Liquefaction Plants

The substantial expansion of global liquefaction capacity that began in 2016 continued through 2018



Led by additions in
Russia & Australia

Capacity has reached
392.9 MTPA
as of February 2019

Total nominal liquefaction capacity increased by
30.6 MTPA
since the end of 2017

A further
101.3 MTPA
has been sanctioned for development, the majority of which is under construction in the United States

A total of
21.5 MTPA
of liquefaction projects reached FID in 2018 — nearly as much as in the previous three years combined

Significant additional FIDs are expected in 2019
starting with the **15.6 MTPA**
Golden Pass LNG project in February.

A growth of
22%
is expected by 2024 in global nominal liquefaction capacity from February 2019

Liquefaction project developers are poised to drive a wave of new capacity with approximately
843 MTPA
in proposed capacity seeking to come online by 2025

Courtesy of Shell

The substantial expansion of global liquefaction capacity that began in 2016 continued through 2018. Led by significant additions in Russia and Australia, total nominal liquefaction capacity increased by 30.6 MTPA since the end of 2017 (36.2 MTPA of new additions offset by 5.6 MTPA of decommissioned capacity) to reach 392.9 MTPA as of February 2019. A further 101.3 MTPA has been sanctioned for development, the majority of which is under construction in the United States. Approximately 60% of the current liquefaction buildout is expected to be completed by the end of 2020.

The present state of under-construction liquefaction projects means that a rapid rise in capacity over the next two years will be followed by a period of lower capacity additions in 2021-22. This is the result of low investment in recent years, particularly 2016 and 2017 owing to factors like low energy prices, demand uncertainty, and some expectations of surplus LNG supply. A total of 21.5 MTPA of liquefaction projects reached FID in 2018—nearly as much as in the previous three years combined—followed by an FID at the 15.6 MTPA Golden Pass LNG project in February 2019. Significant additional FIDs are expected in 2019. Throughout 2018, proposed projects signed a number of long-term LNG contracts to advance their prospects for FID, while some project sponsors committed to taking on their projects' marketing risk themselves to accelerate development and meet expected growth in LNG demand by the mid-2020s. Liquefaction project developers are poised to drive a wave of new capacity with a total of approximately 843 MTPA in proposed capacity seeking to come online by the middle of the next decade. However, many of these projects will likely need to sign long-term offtake contracts to enable FID and will be competing for the same set of buyers, making it unlikely that all projects will move forward.

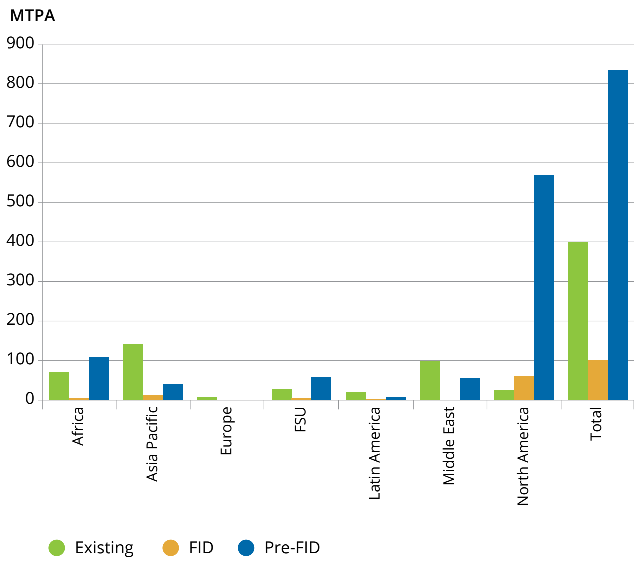
Current proposals not only include many greenfield projects, but also expansion plans at brownfield projects targeted to keep costs down. For example, Qatargas plans to expand capacity by over 30 MTPA to reach 110 MTPA and secure Qatar's status as the world's largest LNG exporter by the mid-2020s. New upstream developments are also providing backfill opportunities for older plants, further heightening supply-side competition.

4.1 OVERVIEW

For the second straight year, nominal liquefaction capacity grew by 7% in 2018, ending the year at 382.9 MTPA. Additions came entirely from new projects rather than expansions of existing liquefaction plants. Commercial starts were reached at both trains of Wheatstone LNG in Australia (8.9 MTPA total), the first two trains of Yamal LNG in the Russian Arctic (11 MTPA total), Cove Point in the US (5.25 MTPA), and Kribi FLNG offshore Cameroon (2.4 MTPA). In addition, commissioning cargoes were exported by Ichthys LNG T1 (4.45 MTPA) in October 2018 and Yamal LNG T3 (5.5 MTPA) in December, with commercial start assumed to have begun at both trains in early 2019. This has brought total capacity to 392.9 MTPA as of February 2019 (see Figure 4.1). Prelude FLNG offshore Australia also reported initial gas production in December, with commercial exports targeted for early 2019.

392.9 MTPA
Global nominal liquefaction capacity, February 2019

Figure 4.1: Nominal Liquefaction Capacity by Status and Region, February 2019



Sources: IHS Markit, Company Announcements

The ongoing wave of liquefaction capacity expansion that began in 2016 is set to continue in 2019, with a total of 51.8 MTPA scheduled to be completed during the year. In addition to Ichthys LNG T1 and Yamal LNG T3, projects totalling 41.8 MTPA in capacity (49% of all sanctioned or under-construction liquefaction capacity) currently have announced commercial start dates before the end of 2019. US liquefaction will lead the way in the addition of new capacity. Corpus Christi LNG T1 and T2 (9 MTPA total), Elba Island LNG T1-T10 (2.5 MTPA total), Cameron LNG T1 and T2 (8 MTPA total), Freeport LNG T1 (5.1 MTPA), and Sabine Pass LNG T5 (4.5 MTPA) are all targeted for 2019 start-up, more than doubling existing US Atlantic Basin capacity. Additional capacity to be added in 2019 includes new liquefaction trains in Russia, Australia, Indonesia, and Argentina.

The commercial start of Ichthys LNG at the beginning of 2019 will make Australia the world's largest source of liquefaction capacity (79.9 MTPA total), surpassing Qatar. After the US, the largest contribution to global capacity in 2019 will come from Australia (12.5 MTPA). Australia, which has been a primary driver of the current phase of capacity growth alongside the US, will complete its current wave of growth after Prelude FLNG and Ichthys LNG T2 come online as no other projects in the nation have reached FID.

Investment in new liquefaction capacity accelerated in 2018. Only 13.3 MTPA in capacity reached FID in 2016 and 2017 combined, including only 8.6 MTPA in greenfield projects. However, 21.5 MTPA in announced capacity reached FID in 2018 followed by another FID in February 2019 at Golden Pass LNG in the US (15.6 MTPA). FIDs were driven by factors including higher energy prices and an expectation that the relatively low aggregate capacity expected to be added in the early 2020s by under-construction projects will mean that the market will need new projects within several years to meet global demand growth. Much of the capacity sanctioned in 2018 came from the 14 MTPA LNG Canada T1-2, its nation's first project to be sanctioned. Only one train to reach FID in 2018, Corpus Christi LNG T3 (4.5 MTPA), is a brownfield addition; its first two trains reached FID in 2015. The remaining sanctioned projects were both smaller floating proposals in frontier regions, with the 2.5 MTPA Greater Tortue FLNG on the Mauritania-Senegal border and the 0.5 MTPA Tango FLNG in Argentina.

Ahead of a potential near-term supply surplus, buyers have tended toward a preference for shorter-term contracts. This has resulted in limited long-term contracting activity of the type that has traditionally underpinned FIDs at proposed projects. While project sponsors have continued to compete for long-term contracts in order to drive FIDs, confidence that new supply will be needed in the early-to-mid-2020s is increasingly prompting liquefaction partners to take on greater marketing activities themselves. LNG Canada reached FID under an equity marketing model, in which its ownership partners are responsible for feed gas supply and LNG offtake. This shows a strong willingness to take on substantial volume and price risk and represents the largest liquefaction project to take FID under an affiliate marketing arrangement (without pre-FID recontracting) since the Qatari megatrains over a decade ago. Later in 2018, Greater Tortue FLNG (2.5 MTPA) announced FID with majority partner BP committing to marketing the full offtake from its portfolio.

101.3 MTPA
Global liquefaction capacity under construction, February 2019

Much of the 844.8 MTPA in currently proposed capacity is aiming to reach commercial operation by the mid-2020s to meet anticipated demand. Most of these projects will require long-term contracts to be signed to obtain the required financing to reach FID. North America is the source of the majority of this proposed pre-FID capacity (571.6 MTPA), with 293.1 MTPA alone located on the US Gulf of Mexico (US GOM) coastline and another 210.6 MTPA in Canada. After North America,[1] Mozambique, Russia, and Qatar each have large amounts of proposed capacity under consideration. Many of these proposals have proceeded slowly amid a crowded and competitive field. Globally, only 48% of pre-FID capacity is estimated to have entered at least the pre-front end engineering and design (pre-FEED) phase.

Many advanced proposals have sought to underpin an FID by securing long-term offtake commitments for the majority of their capacity. This has become more challenging as buyers have increasingly shown a preference for shorter-term contracts; if this imbalance between term preferences prevents projects from reaching FID, the market could become short by the mid-2020s. However, as in 2018, it is likely that 2019 may see further FIDs without long-term purchase agreements in place, as competition to be one of the new projects to meet expected demand needs in the early-to-mid 2020s accelerates. For example, the sponsors of Rovuma LNG (15.2 MTPA) in Mozambique announced in December 2018 that they would take on all offtake responsibilities under an affiliate marketing model rather than seek third-party contracting to drive FID, which is targeted for 2019.

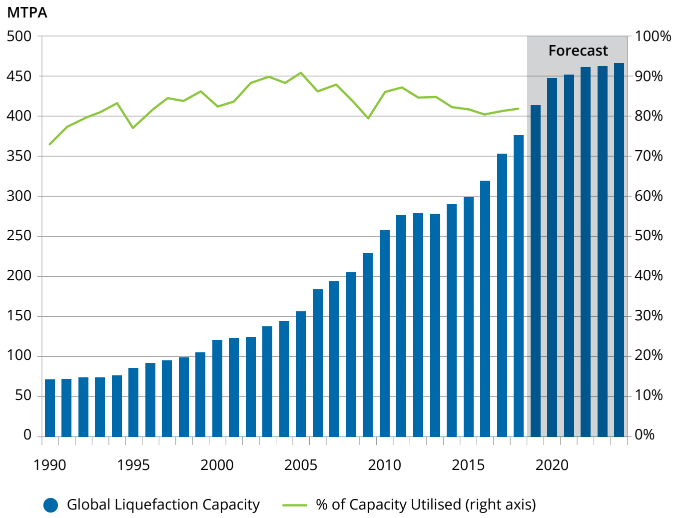
Courtesy of Shell

[1] Please refer to Chapter 10: References for an exact definition of each region.

4.2 GLOBAL LIQUEFACTION CAPACITY AND UTILISATION

Global liquefaction capacity utilisation was 85% in 2018, up from 83% in 2017. This marked the highest utilisation rate since 2013 (see Figure 4.2).

Figure 4.2: Global Liquefaction Capacity Build-Out, 1990-2024



Sources: IHS Markit, Company Announcements

Most existing projects were highly utilised. Average liquefaction project utilisation in Australia, Brunei, Equatorial Guinea, Nigeria, Norway, Oman, Papua New Guinea, Qatar, Russia, the UAE, and the US reached 90% or above of nationwide nameplate capacity in 2018.

The largest sources of incremental supply in 2018 were relatively new projects that continued to ramp up production and add new trains. Yamal LNG in Russia (+7.5 MT from 2017), Wheatstone LNG in Australia (+6.1 MT), Sabine Pass LNG in the US (+5.6 MT), and Gorgon LNG in Australia (+4.3 MT). The first three trains of Yamal and first two trains of Wheatstone each reached commercial operation in 2018; it was also the first full year of operation for Sabine Pass LNG T3-4 and Gorgon LNG T3.

Elsewhere, changes in feedstock availability affected the utilisation of several liquefaction plants worldwide. The impact of new upstream projects in Trinidad that began operation in 2017 led to a 14% increase in LNG output at Atlantic LNG in 2018 after a period of decline earlier this decade. The start-up of the Khazzan field in late 2017 helped Oman LNG increase exports 18% over 2017 and reach record output, driving a current proposal to expand capacity via debottlenecking. While the Egyptian LNG plant at Idku only reached 20% utilisation, this was nearly double its 2017 level thanks to booming gas production from new fields that will continue to ramp up in 2019.

Despite the global overall utilisation increase, certain projects faced technical or upstream issues that decreased their exports. Pipeline challenges contributed to a 9% fall in LNG output by Malaysia. Declining feedstock availability led to a third consecutive annual decline in utilisation at Bontang LNG in Indonesia, where official statements suggested that only four trains remained in operation as of the end of 2018, with two trains assumed to have been decommissioned during the year. Domestic demand and continued strong competition for gas from pipeline customers in Europe contributed to a decrease in Algerian output as well. Further, an unplanned outage in Papua New Guinea following an earthquake in the first half of the year led to a 16% drop in exports.

The existing projects that did not export cargoes in 2017 remained unutilised in 2018. Although SEGAS LNG has not exported a cargo since 2012 due to feedstock constraints, rejuvenated gas production in Egypt coupled with progress in a long-running arbitration dispute has advanced negotiations to restart operation. Yemen LNG has remained offline since 2015 due to an ongoing civil war. In Alaska, Kenai LNG has not exported a cargo since 2015 owing to feedstock constraints and market conditions. After its acquisition by the owner of a nearby refinery in January 2018, it remains unclear whether it will resume exports.

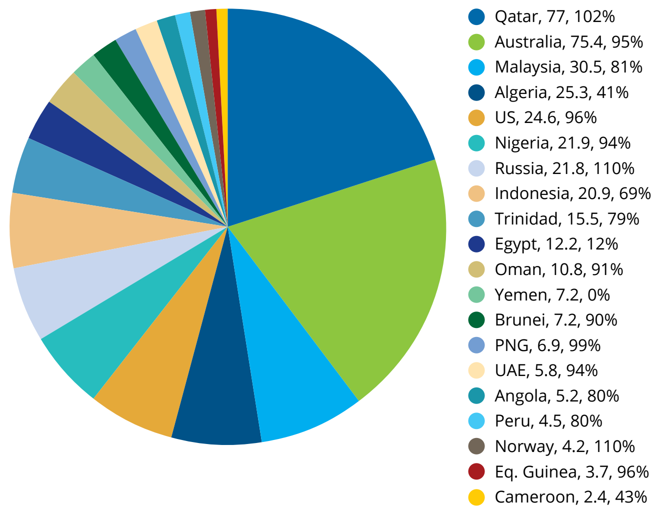
4.3 LIQUEFACTION CAPACITY BY MARKET

Existing

As of January 2019, there are 20 markets with existing liquefaction capacity (see Figure 4.3).[2] In 2018, Cameroon became the newest LNG exporter when Kribi FLNG loaded its first cargo in May. Prior to this, Papua New Guinea in 2014 was the most recent nation to add liquefaction capacity, although the start of commercial operation at Sabine Pass LNG in 2016 marked the first LNG exports from the continental United States.

[2] Includes Yemen, which did not export cargoes in 2016-2018. Although the US has exported from Kenai LNG in Alaska, the US Lower 48 began exporting in 2016 (not including re-exports). Projects in the US Lower 48 are utilising a different resource base.

Figure 4.3: Nominal Liquefaction Capacity and Utilisation by Market, 2018[3]



Sources: IHS Markit, IGU

Qatar remained the world's largest source of liquefaction capacity through 2018 (77 MTPA). However, the assumed commercial start-up of Ichthys LNG T1 in the new year pushed total Australian liquefaction to 79.9 MTPA by January 2019, overtaking Qatar. Capacity expansion in Australia and the US in 2018 further concentrated global capacity in the world's largest producers. Together, Qatar, Australia, Malaysia, Indonesia, Algeria, the US, and Nigeria comprised over 71% of nominal liquefaction capacity at the end of 2018.

+22% by 2024
Expected growth in global nominal liquefaction capacity from February 2019

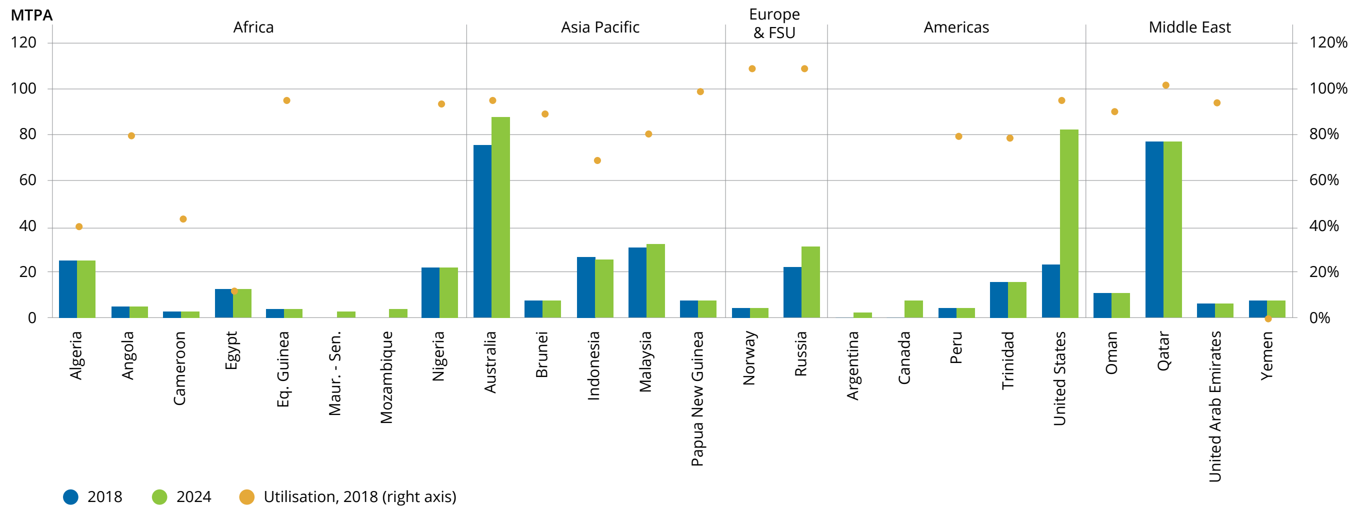
Under Construction

As of January 2019, 101.3 MTPA of liquefaction capacity was under construction or sanctioned for development. This includes Prelude FLNG, which aimed to begin commercial operation in early 2019. More than 75% of global capacity under construction (77.4 MTPA) is located in North America, with LNG Canada as the only non-US project in that category. Although Australia has been a leading contributor in the ongoing wave of capacity additions, its only remaining under-construction trains are Prelude FLNG and Ichthys LNG T2. Further capacity is under construction in Indonesia (4.3 MTPA), Russia (3.6 MTPA), Mozambique (3.4 MTPA), Malaysia (1.5 MTPA), and Argentina (via an 0.5 MTPA floating liquefaction barge). In addition, partners in the Greater Tortue FLNG project to be based offshore Mauritania and Senegal announced FID in December 2018 for the 2.5 MTPA first phase, but have yet to award construction contracts. Similarly, Golden Pass LNG (15.6 MTPA) in the US reached FID in February 2019 but has not yet begun construction.

Capacity additions in the near future will be dominated by US liquefaction. 63.4 MTPA of capacity is sanctioned or under construction on the US Atlantic and Gulf of Mexico coasts. All of this capacity aside from Corpus Christi LNG is at brownfield projects in which existing regasification plants are being converted. Just under half of this capacity is scheduled for completion and commercial start in 2019, including Cameron LNG T1-2 (8.0 MTPA total), Freeport LNG T1 (5.1 MTPA), Corpus Christi LNG T1-2 (9 MTPA total), Sabine Pass LNG T5 (4.5 MTPA), and Elba Island LNG T1-10 (2.5 MTPA total).

Outside of the US and Australia, Argentina's Tango FLNG, Indonesia's Sengkang LNG (0.5 MTPA), and Russia's Vysotsk LNG T1 (0.7 MTPA), Portovaya LNG (2.0 MTPA), and Yamal LNG T4 (0.9 MTPA) are all targeted for commercial start in 2019. This leaves only a narrow majority of total under-construction capacity (59.5 MTPA) scheduled for completion in 2020 or beyond. This is one factor driving the competition by project sponsors to reach FID imminently as projects sanctioned in 2019 will likely be well positioned to respond to anticipated growth in gas supply needs following the limited expected capacity additions in the first years of the 2020s. This likely helped prompt the FIDs taken by LNG Canada, Greater Tortue FLNG, and Golden Pass LNG in 2018 under affiliate marketing arrangements.

Figure 4.4: Nominal Liquefaction Capacity by Market in 2018 and 2024



Note: Liquefaction capacity only includes existing and sanctioned projects expected online by 2024.
Sources: IHS Markit, IGU, Company Announcements

[3] Utilisation is calculated based on prorated capacity. Indonesian prorated capacity is higher than nominal capacity due to decommissioning of two trains at Bontang LNG, assumed in December 2018.

Proposed

There is approximately 842.5 MTPA in pre-FID liquefaction capacity worldwide. Concerns about how many projects can be supported by expected global demand growth have resulted in fierce competition for offtakers by proposed projects. The large number of pre-FID projects as well as uncertainty over future LNG demand and the near-term supply build-up have made it difficult for most proposals to secure offtake deals. This could lead to the market being short of capacity in the mid-2020s if it prevents sufficient FIDs. However, some project sponsors with experience in LNG marketing and confidence in the economics of their proposals may decide to accelerate development by taking FID under an affiliate marketing model, as LNG Canada and Greater Tortue FLNG did in 2018.

The majority of proposed capacity lies in Canada (211 MTPA) and the US (329 MTPA). 89% of proposed US capacity is located on the Gulf of Mexico. North America holds a commercially-recoverable gas resource of over 2,200 trillion cubic feet (Tcf). Feedgas for these proposals will come from a variety of supply basins, although the vast and interconnected gas pipeline network across North America allows natural gas to be procured securely from any number of supply sources. Notably, the largest US proposal in the Pacific Basin, the approximately 20 MTPA Alaska LNG project, aims to use stranded gas from the North Slope.

Most existing and under-construction US LNG projects have been structured as tolling facilities, with capacity holders procuring feed gas from the interconnected North American pipeline network, or have sold Henry Hub-indexed LNG on a free on board (FOB) basis. In a competitive LNG market, some US LNG projects have sought to differentiate themselves by offering a wider variety of commercial structures. These range from vertical integration with upstream resource ownership to alternative pricing mechanisms, such as price linkages to oil or LNG-specific markers. Golden Pass LNG is the first US LNG project to pursue affiliate marketing rather than signing long-term contracts with third parties before FID.

Most Canadian proposals are located on the nation's Pacific coastline in British Columbia. These proposals intend to source feedstock from the Western Canadian Sedimentary Basin but will require significant investment in lengthy greenfield pipelines to connect the upstream resources to the coastal liquefaction plants. This challenge has contributed to the high capital expenditure estimates that have led to the stalling or cancellation of several Canadian proposals. LNG Canada became the first proposal in the nation to reach FID when it did so in 2018, and the success with which the pipeline associated with the project can be completed, despite ongoing challenges from First Nations leaders, could be indicative of the prospects for pre-FID capacity on the British Columbia coast. Another 47 MTPA of estimated capacity is proposed on Canada's Atlantic coast; proposed feedstock sources for these projects include gas from Western Canada and the Eastern US.

After the successful start-up of Yamal LNG in 2018 confirmed the potential of commercialising stranded Arctic gas resources, Russia aims to continue its ambitious plans in the region. Building on experience gained in the under-construction Yamal LNG T4 (0.9 MTPA), proposals largely aim to use indigenously produced components to build their projects. This strategy is driven by the goals of reducing costs and exchange rate risk while also insulating sponsors from the risk of potential future sanctions. The largest project among Russia's 59.3 MTPA in pre-FID capacity is the three-train Arctic LNG-2 (19.8 MTPA total), another project led by Yamal LNG operator Novatek. The project aims to take FID in 2019 and will utilise three domestically-produced gravity-based structures to be built in Murmansk before being shipped complete for installation in the waters off Gydan. A third Novatek proposal in the region, Arctic LNG-1, is targeted for later development. Other Russian project proposals include an additional 5.4 MTPA train at the existing Sakhalin-2 plant on the Pacific coast, the nearby Far East LNG proposal (6.2 MTPA), the 10 MTPA Baltic LNG project on the Baltic Sea, and a second train (0.66 MTPA) at Vysotsk LNG, all of which are targeting FID in 2019.

African proposals account for 111 MTPA in pre-FID capacity. Of this capacity, 81 MTPA is on the east coast of the continent and aim to follow Mozambique's Coral South FLNG (3.4 MTPA), the first project to reach FID underpinned by the vast new gas discoveries offshore East Africa. 50 MTPA of this capacity is in Mozambique, where the Mozambique LNG (Area 1) (12.9 MTPA) and the Rovuma LNG (15.2 MTPA) projects are both seeking to reach FID in 2019. The two projects have followed different approaches toward sanctioning. As of February 2019, Mozambique LNG has struck seven preliminary or confirmed offtake agreements, including an innovative flexible hybrid contract to sell volumes to buyers in Japan and Europe, as it seeks enough sales to enable FID. The owners of Rovuma LNG, however, agreed in December 2018 to commit to affiliate marketing, taking on contracting risk themselves in order to drive project development forward. Just north of the volumes targeted for Mozambican projects lie offshore reserves tied to the 15 MTPA Tanzania LNG proposal, which aims to begin operation in the second half of the 2020s. Also in East Africa, a 3 MTPA liquefaction project has been proposed in Djibouti to utilise gas from neighbouring Ethiopia.

In West Africa, Nigeria LNG has scaled back its expansion plan to a single 8 MTPA train and hopes to reach FID by the end of 2019. The sponsors of the cross-border Greater Tortue FLNG in Mauritania and Senegal have plans to eventually add a second floating phase, and the resources supporting the project could lead to several more floating and/or larger-scale onshore liquefaction projects in both Mauritania and Senegal in the long term, either as additional cross-border schemes or individual single-market projects. Additional floating projects have been proposed in Republic of Congo, Equatorial Guinea, and Cameroon.

In the Asia Pacific region (40.8 MTPA proposed), Australia is home to only four active proposals for new trains despite its recently-gained position as the world leader in liquefaction capacity. Australia may instead see more development of gas fields to backfill existing plants. The Browse field could fill spare capacity at North West Shelf LNG, while the Scarborough field has been proposed to backfill North West Shelf or Pluto LNG and potentially drive construction of a new 5 MTPA train at Pluto. Both fields had previously been the subject of floating liquefaction proposals. Indonesia (15.6 MTPA) and Papua New Guinea (12 MTPA) are far greater sources of pre-FID capacity, with the majority of the Papua New Guinea proposals seeking FID in 2019.

In the rest of the world, pre-FID capacity is dominated by the proposed expansion of Qatargas. Having observed a moratorium on new gas development in the North Field for over a decade, Qatar announced an end to the policy in 2017 and signalled plans to increase its liquefaction capacity. After two announcements that it had increased the scope of its plans, Qatar currently plans to bring its total capacity to 110 MTPA and regain its position as the global leader in LNG export capacity in the face of ongoing US and Australian expansion. Its expansion plan includes four megatrains, listed at 7.8 MTPA each in the FEED scope of work announced in March 2018. Qatar aims to take FID in 2019, potentially with foreign partners. It targets first LNG by end-2023 and hopes to complete the expansion by end-2024.

As in Australia, backfill at mature projects may increase output from nations where new nominal capacity will be limited or non-existent. Discussions aimed at securing Venezuelan and cross-border resources to solidify utilisation increases at Trinidad's Atlantic LNG continue, and gas could arrive from the Dragon field as early as 2020. In Egypt, production from new fields like Zohr and West Nile Delta is likely to allow for increased output at the underutilised Egyptian LNG plant and the long-idle SEGAS LNG. Potentially more significant in the long-term are emerging proposals to feed Egypt's plants with gas from fields offshore Israel and Cyprus. First pipeline gas exports from Israel to Egypt are expected to begin in 2019, and while these initial volumes are not explicitly tied to liquefaction, they are likely to help a gas surplus in Egypt and facilitate greater LNG exports.

Courtesy of Shell

Decommissioned

No train has been formally announced as decommissioned since Arun LNG in Indonesia, which was then converted to a regasification terminal. However, Bontang LNG has confirmed only four trains are operational at the plant, meaning that an additional two trains of the plant are assumed to have been decommissioned at end 2018[4]. Two trains had initially been taken offline and presumed decommissioned in the early 2010s. Elsewhere, limited decommissioning activity is expected in the near term. Kenai LNG in Alaska, which went into preservation mode in 2017, has not exported a cargo since 2015. After being sold to refiner Andeavor in January 2018 for likely integration with its nearby refinery, it is unclear when or if it will resume exports. Aside from Kenai, 33.6 MTPA of global liquefaction capacity is at plants that have been in operation for 35 years or longer as of February 2019, including trains at Arzew LNG in Algeria, Bontang LNG in Indonesia, and Malaysia LNG Satu. Ageing trains may be decommissioned for technical reasons, but these plants have not made any such announcements. In November 2018, Abu Dhabi officials announced that the first two trains of ADNOC LNG (formerly known as ADGAS) would undergo a refurbishment process in the coming years to maintain the project's full capacity. The trains began commercial operation in 1977. While younger in age, the three trains of Oman LNG were to be taken offline in 2025, but the arrival of new feedstock from the Khazzan tight gas field since 2017 has shifted the nation's gas balance. This has led Oman not only to cancel its decommissioning plans but also to explore a debottlenecking of the plant, which it hopes will add 1-1.5 MTPA in capacity over 2019-20.

[4] The 5.6 MTPA in capacity at the two trains assumed to have been decommissioned at end-2018 is not included in totals of year-end liquefaction capacity for Indonesia referenced in charts in this chapter.

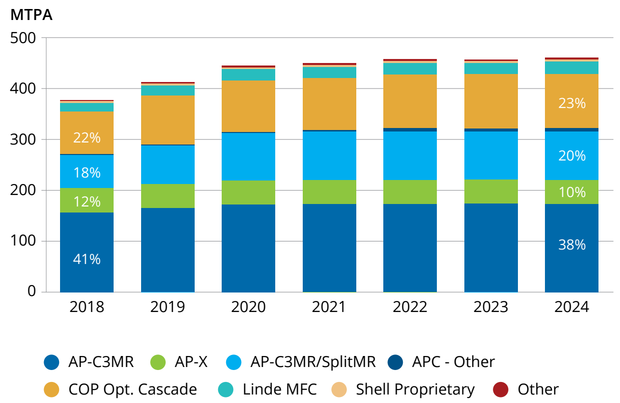
4.4 LIQUEFACTION PROCESSES

Air Products liquefaction processes remained the most widely used in liquefaction in 2018, totalling 72% of global capacity (see Figure 4.5) The most widely used process was AP-C3MR™ at 42% of global capacity, while AP-C3MR/SplitMR® accounted for 18% of capacity and the AP-X® process accounted for 12% of capacity worldwide. Air Products processes are used in much of the capacity that began operation in 2018; the AP-C3MR™ design is used at Yamal LNG in Russia, and the AP-C3MR/SplitMR® process is used at Cove Point LNG in the US. These processes will be used in projects set for 2019 start-up as well. AP-C3MR™ is to be used at Cameron LNG in the US and AP-C3MR/SplitMR® is set for use at Freeport LNG in the US and Ichthys LNG in Australia, helping drive its share of total liquefaction to 20% by 2024. All global capacity to use the AP-X® process is in the existing Qatari megatrains, and its share of global liquefaction capacity will be bolstered if it is selected for the four new megatrains proposed to expand Qatargas.

Air Products also has a central role in most existing or under-construction floating liquefaction. AP-N™ process is used in PFLNG Satu and the under-construction PFLNG Dua, and the AP-DMR™ process will be used at Coral South FLNG. While Shell's proprietary Floating LNG process is used at Prelude FLNG, the vessel does incorporate a cryogenic heat exchanger provided by Air Products. However, Kribi FLNG—which, unlike the previous LNG FPSO projects, is a converted floating liquefaction unit rather than a purpose-built one—uses the Black & Veatch PRICO® process.

Over 21 MTPA in new liquefaction is expected to come online with the ConocoPhillips Optimized Cascade® process by 2022. The process, well-suited for dry gas, is particularly prominent in US and Australian projects. It was used in the 8.9 MTPA Wheatstone LNG project that came online in 2018. It is also used in the under-construction Corpus Christi T1-3 (13.5 MTPA total) and Sabine Pass LNG, including the 4.5 MTPA T5 expected online in early 2019. By 2020, it will have been used in 62.2 MTPA in new liquefaction capacity to have come online since 2016, all of which is in the US and Australia. By 2024, it is expected to be used in 23% of global liquefaction.

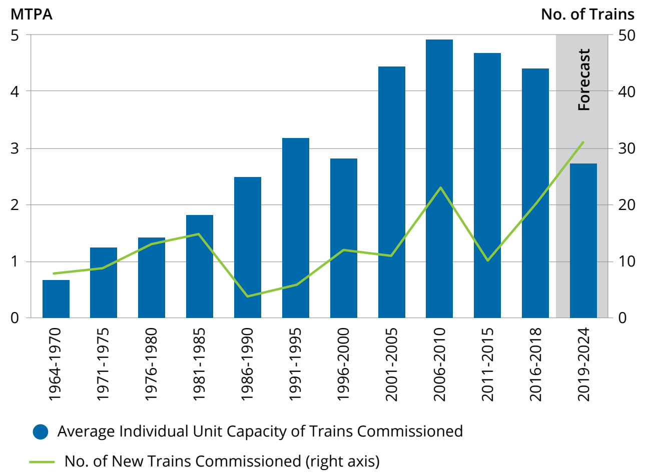
Figure 4.5: Liquefaction Capacity by Type of Process, 2018-2024



Source: IHS Markit

Smaller or modular trains are increasingly common in liquefaction plant proposals (see Figure 4.6). This can lower costs by enabling offsite construction and reduce the volume of contracts needed before an FID is reached. Certain liquefaction processes are geared toward smaller train capacities. This approach is particularly common in current North American proposals. Calcasieu Pass LNG T1-18 (20 MTPA total) and Fourchon LNG T1-10 (5 MTPA total) both target FID in 2019 and are among the US proposals to use Chart Industries' IPSMR® process. Magnolia LNG T1-4 (8 MTPA total) plans to use the LNG Limited OSMR® process. Annova LNG T1-6 (6 MTPA total), Jordan Cove T1-5 (7.5 MTPA total) and several US and Canadian floating proposals all plan to use Black & Veatch's PRICO®. Elba Island T1-10 (2.5 MTPA total) is expected to come online by end-2019 with Shell's Movable Modular Liquefaction System (MMLS). In Russia, Novatek's proprietary Arctic Cascade process will be used for the first time in the under-construction Yamal T4 (0.9 MTPA), targeted for completion in 2019.

Figure 4.6: Number of Trains Commissioned vs. Average Train Capacity, 1964-2024



Sources: IHS Markit, Company Announcements

4.5 FLOATING LIQUEFACTION

161.6 MTPA
Proposed floating liquefaction capacity, February 2019[5]

Cameroon's Kribi FLNG (2.4 MTPA) began exports in 2018, becoming the second floating liquefaction project in operation, and the first to utilise a liquefaction unit built from a converted LNG vessel. The plant followed the purpose-built PFLNG Satu in Malaysia (1.2 MTPA), which started exports in 2017 in a major milestone for the LNG industry. An additional 11.5 MTPA in floating liquefaction capacity has reached FID and is anticipated to come online by 2022, with the purpose-built Prelude FLNG in Australia (3.6 MTPA) and the barge-based Tango FLNG in Argentina (0.5 MTPA) expected to start operations in 2019.

As of January 2018, there is 161.6 MTPA of pre-FID floating liquefaction capacity proposed worldwide across 21 projects. Including existing and sanctioned projects, a combined 80% of this capacity is located in Canada (74.4 MTPA) and the US (69 MTPA). Other proposals exist in Argentina, Australia, Cameroon, Republic of the Congo, Djibouti, Equatorial Guinea, Indonesia, Malaysia, Mauritania-Senegal, Mozambique, Papua New Guinea, and Russia (see Figure 4.7).

Floating liquefaction projects, which are generally smaller in capacity (approximately 0.5 MTPA-4 MTPA) than onshore liquefaction plants, can allow for the commercialisation of stranded offshore gas resources. Their smaller capacity can enable them to underpin FID with fewer offtake contracts or with contracts to deliver to buyers with lower needs. Barge-based floating projects, which tend to be the smallest (around 0.5 MTPA), are generally based at or near the shoreline and supplied by gas from onshore resources.

Through offsite construction, LNG FPSO projects aim to gain cost advantages over onshore construction. Some initial projects have experienced delays and cost escalation as they confront challenges of the new technology. As floating liquefaction is a technology still in its relative infancy, the potential cost benefits of LNG FPSO technology will become clearer as more projects reach start-up. The lower infrastructure investment that may be required, particularly for projects based on a conversion model, and the ability of LNG FPSO vessels to serve multiple projects during their operational lifetimes, make the model especially suited for smaller, isolated gas resources that would be exhausted in a relatively short timeframe.

Offshore floating projects use either purpose-built or converted vessels for liquefaction. PFLNG Satu and three of the five floating liquefaction projects that are under construction or have reached FID are using purpose-built vessels. After arriving at its site offshore Australia in mid-2017, Prelude FLNG began gas production in late 2018 and anticipates first exports in early 2019. PFLNG Dua anticipates its newbuild vessel sailing to its site in early 2020 for commissioning. In Mozambique, Coral South FLNG aims to begin operation in early 2022. The 3.4 MTPA project reached FID in 2017 after being prioritised by project sponsors to rapidly commercialise offshore gas resources, demonstrating the viability of investments in Mozambique's Rovuma basin and paving the way for future liquefaction developments in the market.

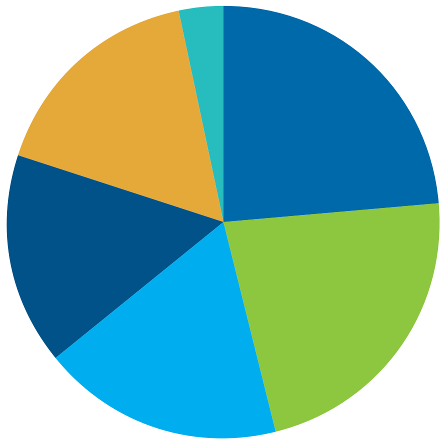
The Tango FLNG barge (0.5 MTPA), which is being delivered to Argentina to help commercialize seasonal gas surpluses in the nation, was originally built for use in Colombia. Then known as Caribbean FLNG, the Exmar-owned vessel had been looking for a new charterer since Colombia's liquefaction plans were cancelled in 2016. A proposal to use the barge to liquefy Iranian gas for export fell through in early 2018. Argentina's use of the barge is an example both of the flexibility the technology offers and the quick development timeframe possible when barges are available for charter. The ten-year charter between Exmar and Argentina's YPF was only signed in November 2018, and first exports are anticipated in the second quarter of 2019.

Conversion schemes are also emerging as an option for floating liquefaction, and the first such project to begin operation was Kribi FLNG in 2018. After approximately 40 Tcf was discovered between Mauritania and Senegal in recent years, Greater Tortue FLNG was proposed to commercialise the 15 Tcf cross-border Ahmeyim/Guembeul offshore field. The project's first phase (2.5 MTPA) reached FID in late 2018 based on a conversion scheme, with project partner BP committing to take the entire offtake into its portfolio. The project targets first gas in 2022, and may pave the way for further floating and onshore liquefaction capacity in Mauritania and Senegal.

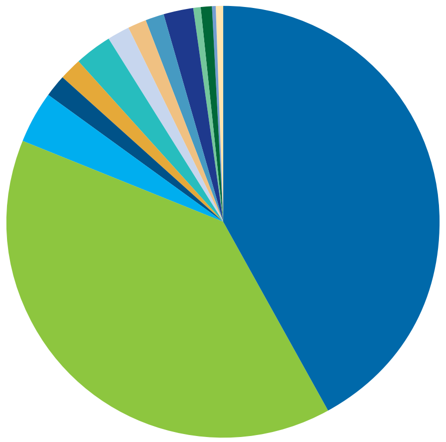
[5] This number is included in the 842.5 MTPA of total proposed global liquefaction capacity quoted in Section 4.1. It excludes the 15.1 MTPA of FLNG capacity in operation or having reached FID.

Figure 4.7: Under Construction and Total Proposed Floating Liquefaction Capacity by Market in MTPA and Share of Total, February 2019

Existing and under construction



Total proposed



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

2017-2018 Liquefaction in Review

Capacity Additions	New LNG Exporters	FIDs	Floating Liquefaction
+20.6 MTPA Additions in global nominal liquefaction capacity in 2018	**+1** Number of new LNG exporters in 2018 (Cameroon)	**37.1 MTPA** Total capacity to reach FID between January 2018 and February 2019	**3.6 MTPA** Floating liquefaction capacity existing as of February 2019
Nominal liquefaction capacity increased from 362.3 MTPA at end-2017 to 382.9 MTPA at end-2018, as 26.2 MTPA of additions were offset slightly by 5.6 MTPA of retirements. 10.0 MTPA of capacity then reached commercial operations in January and February 2019. 101.3 MTPA was under construction or sanctioned for development as of February 2019. 842.5 MTPA of new liquefaction projects have been proposed as of February 2019, primarily in North America. Qatar has proposed a major capacity expansion.	Cameroon joined the list of LNG exporting nations with the start-up of Kribi FLNG in 2018. Argentina's barge-based Tango FLNG project will begin exports in 2019. A number of new exporters could join the market in the coming years with proposals in emerging regions. Mozambique, Mauritania-Senegal, and Canada have large sanctioned projects under development.	Only 13.3 MTPA of liquefaction capacity reached FIDs in 2016 and 2017 combined. Five projects reached FID between January 2018 and February 2019, in Canada, the US, Mauritania-Senegal, and Argentina. Many projects could follow in a new wave of FIDs supported by traditional long-term offtake contracts or affiliate marketing, with 98.7 MTPA in proposals aiming to reach FID by June 2019.	The first exports from an LNG FPSO project, PFLNG Satu, commenced in 2017, followed by Kribi FLNG in 2018. Seven floating liquefaction projects have reached an FID. Tango FLNG and Greater Tortue FLNG were two of the four LNG FPSO projects sanctioned in 2018. 11.5 MTPA of floating liquefaction capacity was under construction or sanctioned as of February 2019. 161.6 MTPA of additional floating liquefaction capacity has been proposed as of February 2019.

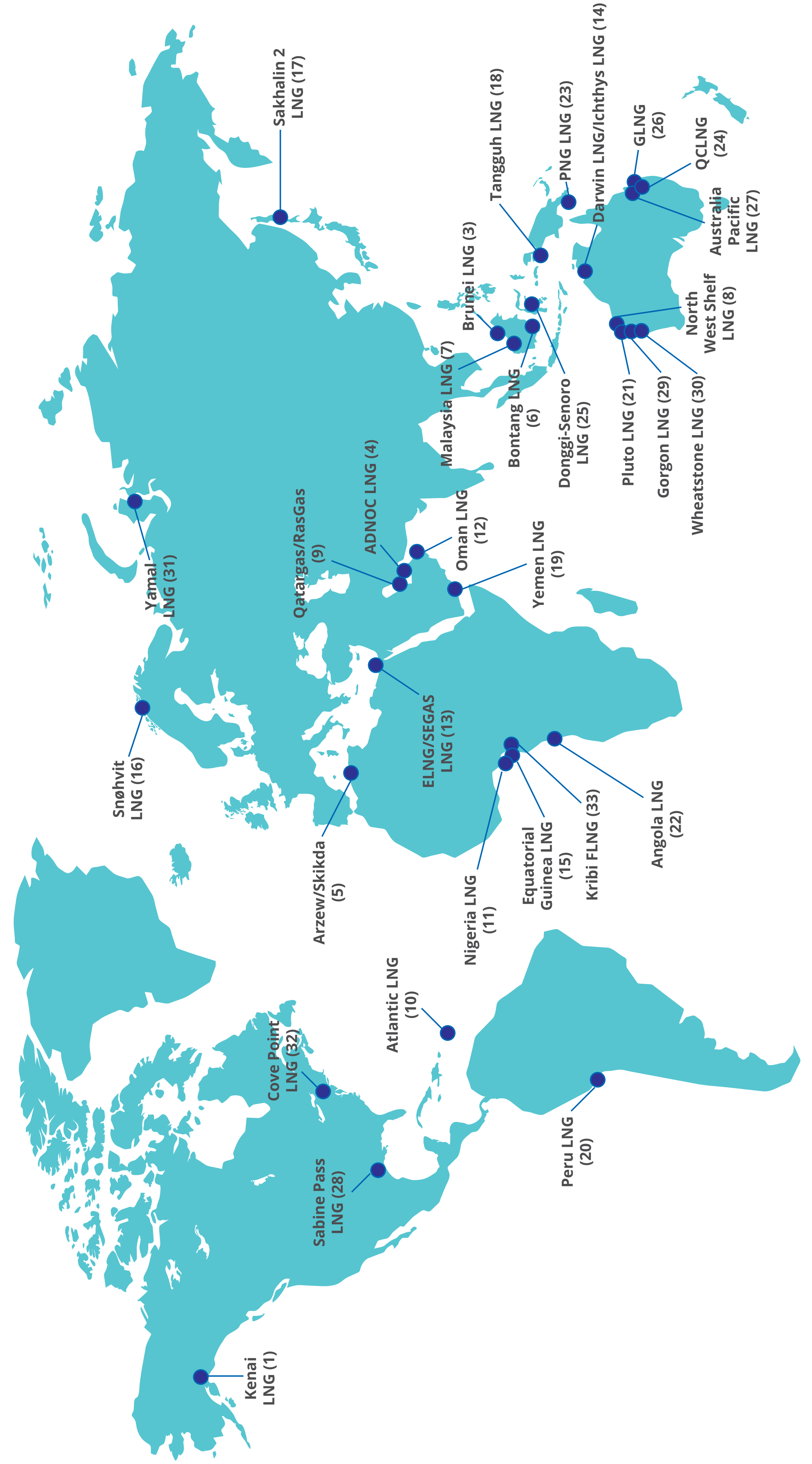


Figure 4.8: Global Liquefaction Plants, February 2019

Note: Numbers in parentheses behind project names refer to Appendix 1: Table of Global Liquefaction Plants.
Source: IHS Markit

4.6 RISKS TO PROJECT DEVELOPMENT

While there have been real improvements in LNG flexibility, which can contribute to easing supply shortages, uncertainties remain for the future evolution of gas markets. This includes a risk of tightening from insufficient investment in production and infrastructure capacity, and questions surrounding future shipping capacity growth - a pre-condition for LNG market flexibility. These uncertainties could have an impact on price volatility and hurt consumers – especially the most price-sensitive emerging buyers – and cause additional security of supply concerns.

LNG flexibility has evolved with the development of secondary markets, emphasizing the role of portfolio players and the growing role of emerging LNG buyers, and of the development of market liquidity on trade and new contracts. To address these issues, supply flexibility remains a key prerequisite to ensure further global gas trade development and security. Yet the priorities in terms of flexibility differ for long-term traditional buyers who seek the removal of destination clauses, and new emerging buyers whose priority is more focused on procuring short-term supply, usually for prompt execution.

Changing LNG markets are also reshaping shipping needs and the risk of a lack of timely investment in the LNG carrier fleet could pose a threat to market development and security of supply, which could materialise even earlier than the risk of insufficient liquefaction capacity.

The traditional risks facing liquefaction project development continue to include project economics, politics and geopolitics, regulatory approvals, partner priorities and ability to execute, business cycles, feedstock availability, domestic gas needs, fuel competition, and marketing and contracting.

However there has been progress and 2018 saw 4 liquefaction project FIDs (LNG Canada, Corpus Christi Train 3, Tango FLNG, and Greater Tortue FLNG).

LNG Carrier and Samcheok Terminal - Courtesy of KOGAS

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 uncertainty, which has been a challenge in some emerging liquefaction regions, can also impact project costs.

LNG Canada, for example, rebid EPC work on a competitive basis, and the government of British Columbia, where LNG Canada is located, also announced a series of fiscal measures intended to improve projects' competitiveness. This combination of measures has been successful, resulting in the sanctioning of the LNG Canada project in 2018.

Other projects, such as the now state-owned Alaska LNG project, 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.

It is estimated that the production deficit gap in 2025 will be about 50 MTPA, which would need to be sanctioned soon to be on-stream in that timeframe. By assessing breakeven prices for potential future LNG projects, it is possible to predict which projects will most likely be developed, being those projects with the lowest breakeven cost.

Politics, Geopolitics, and Regulatory Approvals

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

Some projects in operation have been impacted by security issues, including Yemen LNG which declared force majeure in 2015 and remains offline owing to an ongoing civil war.

US and European Union (EU) sanctions remain a challenge to LNG project development in Russia and Iran, providing greater uncertainty around future project development in those markets, though Yamal LNG was ultimately able to secure financing and has begun exports. In Iran, the sanctions lifted in 2016 were reimposed by the US at end 2018. Iran's LNG ambitions now face numerous challenges, as Iran is unable to use US-sourced liquefaction technology, and secondary sanctions remain in place, meaning that EU sourced technologies and equipment for Iran LNG projects have also been affected by these sanctions, as are payment mechanisms.

Extensive regulatory requirements, particularly in developed supplier markets, can be time-consuming and costly, although in many cases the process, while rigorous, is nonetheless predictable. In some circumstances, the review process can be protracted due to local opposition, based on environmental or Not In My Backyard (NIMBY) grounds. Other potential LNG exporting markets, such as 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 uncertainty and macroeconomic conditions have been important factors in the reduction in foundational contracting activity and FIDs over the past few 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 that market'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 several proposed projects are being developed by companies with limited or no direct liquefaction, or major project development, experience.

Feedstock Availability, Domestic Gas Needs, and Fuel Competition

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

Coal seam gas-based projects in Eastern Australia faced significant pressure in 2017 to supply more gas locally in response to high domestic gas prices. Fracking restrictions in several states 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 to ensure sufficient domestic gas supply in 2018 and 2019. In June 2018, the Australian Energy Market Operator (AEMO) advised that Australia is no longer in danger of a domestic gas supply shortfall. AEMO's 2018 Gas Statement of Opportunities (GSOO) has found a change in international market dynamics, lower demand for gas-powered generation, new pipeline interconnections and the Federal Government's Australian Domestic Gas Supply Mechanism have delivered an improved outlook for the east-coast gas markets.

Progress on new upstream developments has accelerated over the past two years, which will extend the life of some existing liquefaction plants by either supplying them directly or being used to fulfil domestic demand. For example:

- The Browse gas fields are being proposed to backfill North West Shelf LNG in Australia. Australia's oldest LNG plant is for the first time set to process third-party gas after a landmark agreement was reached among the North West Shelf venture partners that will ensure the plant can keep running after the venture's own gas runs out. The deal, agreed in July 2018 by the partners also paves the way for gas from Woodside Petroleum's Browse fields to be processed at the NW Shelf venture's LNG plant in Karratha.

- ConocoPhillips and its co-venturers are proposing to develop the Barossa hydrocarbon resources located offshore about 300 kilometres north of Darwin to provide a new source of gas to backfill the Darwin LNG facility from 2023 when the existing offshore gas supply from Bayu-Undan is expected to be exhausted. Barossa FEED phase will be completed in 1Q2019 and FID is targeted towards the end of 2019.

- Exports from Oman LNG could be extended as a result of new production from the Khazzan field that began in the last quarter of 2017. With the new stream feeding straight into the plant, all three liquefaction trains are now operating at almost full capacity.

- In Egypt the successful commercialisation of new gas fields is supporting a return to exports on a larger scale. The latest turnaround in Egypt's gas fortunes is due to production from the Zohr field, as well as some fresh BP finds. Located off the market's northern coast, Zohr is the largest gas deposit in the Mediterranean and its gas reserves are not only bringing an end to the need for LNG imports but also meeting local demand and supporting a resumption of LNG exports. The Damietta LNG facility has agreed to restart exports from the plant, while Idku LNG had already recommenced limited shipments in 2016. Damietta ceased export shipments in February 2013, citing insufficient quantities of feed gas for its liquefaction train, and Idku followed 12 months later, declaring force majeure to its LNG customers due to ongoing diversions of gas supplies to the local market.

- In Trinidad BP and Shell have been working to extend the operational life of Atlantic LNG in Point Fortin. In 2018 the government signed an agreement to purchase natural gas from Venezuela's offshore Dragon field (via Shell's Hibiscus platform), providing much needed additional feedstock for the Atlantic liquefied natural gas (ALNG) project. In recent years, ALNG project stakeholders have also identified several new fields to shore up LNG production. In 2017, BP started production from the Juniper field and also sanctioned the development of the Angelin field, expected to start production in 2019. BP has also commissioned the Trinidad onshore compression project to increase feedstock supply to the facility. Additional offshore fields that could provide natural gas feedstock for the project include BHP Billiton's LeClerc field and BP's blocks near Juniper and Cashima fields.

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

Marketing and Contracting

The long-term contracting environment remained challenging in 2018. With expectations that the significant LNG supply build-up 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 were signed 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 term 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. Japan's trade ministry has also advocated the re-working of current LNG supply contracts to remove restrictive destination clauses, deemed to be 'anti-competitive'.

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 have 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 require long-term LNG sales 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. The recently sanctioned LNG Canada project is different in that it isn't underpinned by long-term sales contracts. These agreements are typically necessary to provide a level of certainty to the oil and gas companies and their financiers that guaranteed buyers existed for the output and revenues. Instead, each of the partners in LNG Canada is responsible for providing their share of the natural gas to be liquefied and would also oversee marketing their share of the LNG.

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.
Regulatory Approvals	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	Markets 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.

4.7 UPDATE ON NEW LIQUEFACTION PLAYS

The current wave of new global LNG export capacity development is due online by the end of 2020. In the short run, this massive capacity addition is likely to result in a surplus and increase competition – however this could be short-lived with dynamic growth in Asian emerging markets. Without new investment, the continuous growth of the LNG trade could result in a tight market by 2023. Owing to the long lead time of such projects, investment decisions need to be taken in the next few years to ensure adequate supply through the 2020s.

The pickup in the second half of 2018 and 1Q2019 in new LNG export project approvals suggests that the risk of an abrupt tightening in global LNG around the mid-2020s may be easing. A steady flow of additional projects will still be required to meet demand and there is still considerable disagreement between buyers and sellers about what kind of business models and contracting structures will underpin new investment decisions in the new global LNG order. However, the outlook for new projects is more optimistic, as an increasingly liquid, flexible and transparent trading space is creating opportunities to spread market risks more evenly among stakeholders and along the value chain.

While projects that can come to market relatively quickly and at a lower cost (such as the brownfield Qatari expansion) are the ones most amenable to the industry's current focus on capital discipline and short-cycle investments, large-scale greenfield projects can also find a place in the new gas order supported by new emerging market solutions.

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 fronts in 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.

Middle East

In Qatar, the 12-year self-imposed moratorium on further North Field gas utilisation has been removed and a major Expansion Project is under development by Qatar Petroleum. Chiyoda has been contracted to carry out FEED work for a total of four new 7.8MTPA production trains. When the expansion plans were unveiled last year the production capacity was to be increased from the current 77MTPA to 100MTPA. However, based on the good results obtained through recent additional appraisal and testing, they decided to add a fourth train (to the three trains previously announced), expanding Qatar's export capacity by around 43% to 110MTPA. Qatar Petroleum plans to make its final investment decision on the expansion and announce partners by the end of 2019, and aims to be onstream in 2024.

Iran's first LNG export project, Iran LNG with a planned capacity of 10.8MTPA, has been stalled again due to the impact from the US sanctions. Work on the plant hit a wall in 2012 when sanctions stopped Iran from bringing in specialist liquefaction equipment. Much of the offsites and utilities facilities for this project, including power station and LNG and LPG tanks, are in place.

United States

The emergence of the United States as a global exporter challenges the traditional features of LNG trade. The wave of liquefaction projects being developed in the US ensures ample supply and growth of LNG trade but also challenges the traditional features of supply contracts. The emergence of US exports with flexible destination and gas-indexed pricing presents a different model from the standard fixed-delivery, oil-indexed supply agreements. The United States appears likely to challenge Qatar in Asian and European LNG markets as a new global player.

The United States began exporting LNG from the Lower 48 states in February 2016, when the Sabine Pass liquefaction terminal in Louisiana shipped its first cargo. Since then, Sabine Pass expanded from one to four operating liquefaction trains, and the single train Cove Point LNG export facility began operation in Maryland. Two more trains, Sabine Pass Train 5 and Corpus Christi LNG Train 1, began LNG production this year, several months ahead of schedule.

The innovative Elba Island Liquefaction facility (which involves adding 10 small-scale 0.25MTPA modular units to the existing import terminal) is reported as planning a Q1 2019 start-up with trains being progressively placed in-service through 2019.

In November, Sempra announced that Cameron LNG's first train is now slated to enter service in September 2019, with the second and third trains coming online in January 2020 and May 2020, respectively.

The Freeport LNG project was originally planning to have all LNG-producing units in service by the end of 2019, however, the terminal site faced flooding after Hurricane Harvey, and the developer and its contractors are competing for labour with other megaprojects along the U.S. Gulf Coast, forcing delays. The start date for the first train has been pushed back to September 2019, with the subsequent start-ups of trains two and three also pushed back to January 2020 and May 2020 respectively.

As of December 2018, a total of 34 MTPA of LNG nameplate capacity was operational in the US. A further 50 MTPA of liquefaction capacity is in the construction phase and is due to be on-line in 2019/2020. With all currently sanctioned US liquefaction capacity expected to be online by 2020, developers are focusing on the next wave of US LNG supply. In addition to those export projects which are either in operation or under construction, there are nearly twenty other LNG export facilities which have been proposed in the USA - in Texas, Louisiana and Oregon – with a total proposed LNG export capacity of approximately 190 MTPA. Only a few of these multibillion-dollar LNG export projects are likely to advance to final investment decisions (FID), and construction and operation, but even those that do will have profound impacts on U.S. natural gas production, pipeline flows, and the global LNG market. With global demand for LNG rising and U.S. natural gas producers needing markets for their burgeoning output, it has not been a question of whether another round of U.S. liquefaction/LNG export facilities will be built, but which developer would be first to FID. In February 2019, ExxonMobil and Qatar Petroleum announced an FID on Golden Pass LNG. Built originally to handle imports from Qatar, Golden Pass LNG will add liquefaction facilities to handle exports from the US.

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, several current customers of US produced LNG are seeking to place some of their contracted volumes via recontracting as well as time or destination swaps to reduce shipping costs.

Many of the sanctioned US project developers act as infrastructure providers under a tolling model. Several 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 sale 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 favourable 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.

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 project, developed by the Alaska Gasline Development Corp (AGDC) stated they are working towards sanction in 2020, with a 2024 start-up. A centrepiece to progress on this project has been the joint development agreement that the AGDC has signed with the state-owned Chinese companies Sinopec, China Investment Corp. and the Bank of China, and although nonbinding, the JDA has been touted as the early stages of a foundational deal to support the gas line as it calls for selling up to 75 percent of the project's LNG production capacity to Sinopec in exchange for a similar percentage of the needed financing. The close proximity of the export facility site to the major North Asian markets is an offset to the high development costs.

A Memorandum of Understanding was signed on August 31, 2018 between FERC and PHMSA, describing how they will coordinate their efforts to expedite the review of applications for LNG facilities. The US regulatory process remains time-consuming and expensive, but it is unlikely to be a major obstacle for most projects.

Canada

The proposed Western Canadian LNG export projects are advantaged by access to abundant, low-cost natural gas from British Columbia's vast resources and the relatively short shipping distance to North Asia, which is about 50 percent shorter than from the Gulf of Mexico and avoids the Panama Canal.

However, the greenfield nature and location of the developments, which require the need for lengthy pipeline infrastructure to transport gas from the Western Canadian Sedimentary Basin 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.

Around twenty LNG export facilities have been proposed in Canada – in British Columbia, Quebec and Nova Scotia – with a total proposed export capacity of 257MTPA of LNG. However, over the past few years, a number of those projects have been cancelled or re-paced. The most notable cancellation was the 12 MTPA Pacific Northwest LNG project, one of the market's highest-profile projects at the time of cancellation.

However, the first Canadian LNG FID was taken in 2018 with the Shell-led LNG Canada project being sanctioned in October. This also marked the first greenfield LNG export project FID globally in five years. The project will initially export LNG from two trains totalling 14MTPA, with the potential to expand to four trains in the future. The LNG export facility will be constructed on a large, partially developed industrial site with an existing deep-water port, roads, rail and power supplies. The project has a 40-year export license and all major environmental permits are in place for the plant and the pipeline. Notably, the project will also achieve the lowest carbon intensity of any LNG project in operation today, aided by the use of aero derivative gas-turbine drivers and the use of hydropower for auxiliary power demand.

Both Pieridae's $10-billion Goldboro LNG project in Nova Scotia and Woodfibre's $1.6-billion project in British Columbia are nearing sanction in a race to be the second LNG project in Canada. The Woodfibre LNG project, backed by the Indonesian RGE Group, is a relatively small endeavour with a capacity of 2.1MTPA, while the Goldboro LNG project is planning to construct a 10MTPA export facility.

Taxes and tariffs could impact the competitiveness of Canadian LNG. 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 regulatory approval process in Canada has generally taken approximately two years to complete, though in some cases the process has been significantly longer. Impacted First Nations, including those with traditional territories along associated pipeline routes, must also be accommodated and provide consent.

Mexico

An LNG export project, Sempra's Costa Azul LNG export facility, has been proposed for Mexico. Sempra has signed three equal volume HOAs for 20-year LNG sales-and-purchase agreements for the 2.4MTPA export capacity of Phase 1 of the project located in Baja California, Mexico. Energia Costa Azul LNG Phase 1 is a single-train liquefaction facility to be integrated into the existing LNG import terminal. A final investment decision for ECA LNG is targeted in late 2019 with potential first LNG deliveries in 2023. In June, TechnipFMC and Kiewit were selected as the EPC contractor for the project.

East Africa

East African LNG will face strong competition from other producers, especially Qatar, Australia and Papua New Guinea, in the race for the rising demand in South-East Asia and West Asia. East Africa benefits particularly from its proximity to India and Pakistan.

The first project in the region to reach an FID in 2017, the Coral South FLNG project offshore Mozambique has contracted its entire 3.4 MTPA capacity to BP and is expected online in 2022.

Several other floating and onshore projects totalling 70 MTPA have been proposed following large offshore dry discoveries in Mozambique and Tanzania. Of these, the Anadarko led Area 1 Mozambique LNG export project anticipates making FID in the first half of 2019, provided they have lined up enough customers for the LNG. LNG is being marketed jointly by the partners, and Anadarko has stated that 8.5 MTPA of contracted offtake is necessary for an FID. The Mozambique LNG project, located between both the Asia-Pacific and European markets, will consist of two liquefaction trains with the capacity to liquefy 12.88 MTPA. The site preparation and resettlement processes commenced in Q4 2017. Mozambique's ongoing debt crisis is a potential obstacle.

Another Mozambique LNG project is the Rovuma LNG Area 4 consortium, which aims to build the world's biggest liquefaction trains outside Qatar, in pursuit of cost savings. The first two liquefaction trains are each to produce 7.6 MTPA, with FID expected in 2019 and an LNG production start date in 2024. Significant progress has been made on marketing and the joint venture partners are in active negotiations on binding sales and purchase deals with some affiliated buyer entities of the Area 4 co-venturers. ExxonMobil will lead construction and operation of liquefaction trains and related onshore facilities for the Rovuma LNG project, while Eni will lead upstream developments and operations. Discussions regarding potential coordination or infrastructure sharing between the Area 1 and 4 partners are ongoing.

LNG development in Tanzania is at a more preliminary stage. Shell and Equinor are still committed to a project, however, significant regulatory challenges remain. Proposals to build a $30 billion two train LNG plant, with total capacity of 10MTPA, have been under consideration since 2011, clouded by policy uncertainty in Tanzania's extractives industry.

West Africa

The Kribi FLNG project offshore Cameroon, commenced exports in April 2018. The project, based on a conversion of an older LNGC by Keppel in Singapore, is the world's first converted FLNG vessel. The Episeyo was converted from the 1975-built Golar Hilli Moss containment LNG carrier with a storage capacity of 125,000 cm. It is designed for a liquefaction capacity of about 2.4 MTPA from four 0.6MTPA trains.

Several projects have been proposed to commercialise approximately 40 Tcf of gas resources in Mauritania and Senegal. The Tortue/Ahmeyim field straddles the territorial waters of Senegal and Mauritania and development of the first project, Greater Tortue FLNG, continues at an accelerated pace only 16 months after the discovery of the gas deposit. 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. Based on experience gained from converting the Hilli LNGC into an FLNG vessel, Golar entered into an agreement with BP to proceed with FEED on the provision of a vessel to service the project. The intention is to use the Golar Gimi LNGC for conversion, in a similar fashion to the Golar Hilli conversion, as the Greater Tortue FLNG vessel. FID on the project was made in December 2018, enabling the FLNG vessel to begin producing cargoes for export expected in 2022. The FLNG facility is designed to provide circa 2.5 MTPA of LNG for global export as well as making gas available for domestic use in both Mauritania and Senegal.

A third FLNG development, the Fortuna FLNG offshore Equatorial Guinea was planning to reach an FID in 2018, however the project has faced significant challenges. Fortuna FLNG was originally planned to be developed by Ophir Energy using Golar's FLNG technology, converting the 126,000 cm LNG carrier Gandria and aiming to produce 2.2 MTPA, but Equatorial Guinea's decision not to extend Ophir Energy's licence on offshore block R, has scuppered the long-delayed LNG project, which was largely expected, given the firm's protracted struggle to find funding.

In Nigeria, expansion at the existing Nigeria LNG complex is currently undergoing a dual FEED study, with the development concept being for two trains with capacities of 3.2 and 4 MTPA. Nigeria LNG has announced that the company is making steady progress towards achieving FID on its expansion project, originally planned for end 2018 but now delayed. This project will increase NLNG's annual production capacity to approximately 30 MTPA.

The much delayed 10 MTPA Brass LNG project continues to undergo a planning review by partners Nigerian National Petroleum Corporation (NNPC), TOTAL, and Eni.

Russia

The 16.5 MTPA Yamal LNG project in the Russian Arctic exported its first cargoes in 2017 and the first cargo from Train 2 was loaded in August 2018, adding 5.5MTPA, doubling the plant's capacity and 6 months ahead of schedule. The third 5.5 MTPA train is expected to start operations early in 2019. During 2018, Yamal LNG shipped several cargoes eastbound via the Northern Sea Route, transiting the ice-covered part of the route in 9 days with no icebreaker escort.

Novatek's Arctic-2 LNG project, with an estimated cost of US$25.5 billion, envisages construction of three LNG trains at 6.6 million tons per annum each, with a total capacity of 19.8MTPA, located on gravity-based structures (GBS) floated in and ballasted down nearshore. Novatek will use Linde's technology for the liquefaction process and Saipem will develop the gravity-based structures. Novatek has announced that the use of GBS systems will reduce construction costs for Arctic LNG 2 by 30% (or approximately $9 B) from what was spent on Yamal LNG. FID may be made as early as the second half of 2019 (the first train is planned to be put into operation in 2023, and the third in 2026). The company is planning to sell up to 40 percent of the Arctic LNG 2 project to foreign partners. Total has signed an agreement with Novatek outlining the terms upon which Total shall acquire a direct working interest of 10% in Arctic LNG 2. The project also attracted a lot of interest from international partners, including Chinese national oil and gas major CNPC, energy giant Saudi Aramco, South Korean public natural gas company KOGAS, as well as from Japanese investors. In May 2018, Novatek announced that it was planning to produce 70 million tonnes of liquefied natural gas annually by 2035.

Additionally, the LNG delivery method for Arctic LNG 2 will also differ from that used for Yamal LNG. Rather than use icebreaking LNG carriers to export the product all the way to markets, Novatek will develop trans-shipment facilities in Norway and Kamchatka. The ice-class tankers will deliver LNG to these terminals, from where the LNG will be loaded into traditional LNGCs for export. The terminals will significantly slash the company's transportation expenses. In November, Novatek completed the first ship-to-ship LNG trans-shipment in the area near the port of Honningsvag in northern Norway. The ice-class LNG tanker Vladimir Rusanov reloaded an LNG cargo delivered from the Yamal LNG facility at Sabetta to the lower ice-class designated tanker Pskov, which then delivered the reloaded cargo to customers in North-West Europe. This approach decreases the travel distance of the Arc7 ice-class tankers and the experience gained from ship-to-ship LNG trans-shipments will be used at Novatek's future large-scale LNG trans-shipment projects.

In mid-2018 Gazprom announced that they and Shell would take an FID on the third train of the Sakhalin 2 LNG plant at the end of 2018 or in early 2019. The expansion would increase the plant's capacity by 50%, from 9.6 to 15.0MTPA. FEED work on the third train has been completed. Sanctions and delays in a third-party gas supply agreement have challenged development of the third train.

In October 2018, Gazprom and Shell signed the Framework Agreement on the joint design concept (pre-FEED) for the Baltic LNG project. The document outlines the next stage of the Baltic LNG project in the lead-up to the FEED stage. During the signing process, the parties noted that the joint feasibility study had been successfully completed. Baltic LNG is a Gazprom long-term project and the project provides for the construction of an LNG plant near Ust-Luga port in Eastern Russia. Projected plant capacity is 10MTPA of LNG, with the potential to increase production by 15m tonnes. It is expected that the plant would be commissioned in 2023.

ExxonMobil with its partner Rosneft is reportedly moving forward with the Far East LNG project, with a final investment decision planned for 2019. They continue to work on their LNG project and have stated that sanctions are not an obstacle to the collaborative work on the project Far East LNG, valued at $15bn, has a planned capacity of more than 6.2 MTPA. The facility would use gas from the Sakhalin-1 venture as a source. The plant's capacity also could be increased from planned initial volumes.

Australia

By the end 2018, Australia's liquefaction capacity, with 20 LNG trains operational, was 84MTPA nameplate capacity. During 2018, LNG start-ups included Wheatstone Train 2 and Ichthys.

The remaining project under construction in Australia, the single train Prelude floating LNG project, was scheduled to begin in late 2018. However, in late December, Shell announced that the wells have been opened and that Prelude now enters start-up and ramp-up, which is the initial phase of production where gas and condensate is produced and is moved through the facility. Once this has concluded the facility will be stabilised for reliable production of LPG and LNG.

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 brownfield expansions on the West Coast.

Woodside plans to monetise the Scarborough development through an expansion of the existing Pluto LNG facility, via a second train with a targeted capacity of between 4 and 5 MTPA of LNG. In February 2018, Woodside announced it would increase its stake in Scarborough, providing greater partner alignment across the project. Woodside has awarded a FEED contract to Bechtel for build a second Pluto LNG train as part of its $US11 billion project. The FEED contract will include the option to construct the train, subject to a positive FID planned for 2020. First LNG is scheduled for 2024.

The Browse development, evaluated in the past as a standalone greenfield project, is now proposed to backfill North West Shelf LNG, with an FID slated for 2021. Both Chevron and Woodside have raised the potential for a pipeline running from Woodside's Scarborough field through to the Burrup Peninsula LNG hub (at the Woodside operated North West Shelf LNG export facility), linking the Scarborough, Pluto, Gorgon, Wheatstone and North West Shelf (NWS) LNG developments, which could ensure these resources are developed efficiently.

With the Bayu-Undan field, which supplies gas to the Darwin LNG plant maturing, the operator ConocoPhillips has been evaluating alternate supply sources. The Barossa field is the primary choice and progress on the FEED phase of the offshore project progressed with the award of three major engineering contracts. These contracts reaffirm Barossa's position as the leading candidate for Darwin LNG backfill, with no alternative projects in the FEED phase. The award of the FEED contracts is another big step towards ensuring Barossa replaces Bayu-Undan production when it ceases in the early 2020s. The Barossa development concept includes a floating production storage and offloading facility (FPSO), six subsea production wells to be drilled in the initial phase, subsea production system, supporting in-field subsea infrastructure and a gas pipeline to Darwin, all located in Australian Commonwealth waters.

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 to feed into the Sunrise LNG project. The agreement, however, did not specify a definitive gas commercialisation plan, indicating development of the field is likely a longer-term opportunity. In 2018, both ConocoPhillips and Shell sold their shareholdings in the Greater Sunrise fields in the Timor Sea to the Timor Leste Government. Both deals are subject to approval from East Timor's Parliament and remaining partners Woodside (33.4%) and Osaka Gas (10%) not exercising their pre-emption rights. The Sunrise LNG project has been stalled for more than a decade, with the Government and the Joint Venture having differing views regarding development plans. Timor-Leste's leaders want to build an onshore LNG plant in Timor, fed by a 150-kilometre pipeline to the south coast hamlet of Beaço from the Greater Sunrise field of the Timor Sea. Building that pipeline to Timor-Leste poses formidable challenges as it would have to cross a seismically active trench called the Timor Trough, which plunges to depths of more than three kilometres.

Papua New Guinea

An expansion of the PNG LNG site in Papua New Guinea gained momentum in 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 Papua LNG project led by TOTAL. The PNG LNG project is planned to be a three-train 8.1 MTPA expansion (each train 2.7MTPA) on the existing PNG LNG site, as ExxonMobil, Total, OilSearch and other shareholders pool their gas resources together to support an integrated expansion of the facility, as opposed to building a second standalone project. The plan will see PNG LNG's export capacity expanded to 16 MTPA at an estimated cost of US$13 billion. Three new LNG trains are underpinned by gas from P'nyang for one train and two trains based on gas from Elk-Antelope. The FEED work at both fields commenced in the second half of 2018, with a final investment decision due by 2020-2021.

Eastern Mediterranean

The SEGAS Damietta LNG plant ceased export shipments in February 2013, citing insufficient quantities of feed gas for its liquefaction train. The Shell Egyptian LNG Idku facility followed 12 months later, declaring force majeure to its LNG customers due to ongoing diversions of gas supplies to the local market. With its dwindling gas reserves unable to meet growing domestic demand, Egypt turned to LNG imports to bridge the gap, positioning the two chartered FSRUs at Ain Sokhna in April and October 2015, respectively. In 2016, the peak year for Egyptian imports, the two FSRUs received 7.5MT of LNG.

2019 appears to signal a potential increase in LNG exports from both the Damietta and Idku LNG export facilities. As recent gas discoveries have led to Egypt becoming self-sufficient for gas again, this has led to an increase in exports. The Egyptian LNG plant at Idku recommenced overseas shipments in 2016. Shell shipped 12 LNG cargoes from the Idku plant in 2018 and plans to increase LNG exports from Egypt in 2019, as it ramps up production from the West Delta Deep Marine field Phase 9B project. Egypt is expected to begin exporting LNG again from the Damietta export plant in 2019. Egypt's Ministry of Petroleum and Naturgy (previously Union Fenosa Gas (UFG)), the operator of the Damietta LNG project in the Nile Delta, have agreed to restart exports from the plant.

The recent string of gas discoveries in Egypt and the East Mediterranean has given rise to the ambition for Egypt to be a regional hub for the trade of LNG. With new production from the Zohr, Atoll, and West Nile Delta Felds enabling LNG imports to be halted in October 2018, the re-emergence of Egypt 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 in the Eastern Mediterranean.

Indonesia

Tangguh Train 3 construction is progressing with the BP-operated LNG export facility in Indonesia adding 3.8 MTPA of production capacity to the existing facility, bringing total plant capacity to 11.4 MTPA. The project also includes two offshore platforms, 13 new production wells, an expanded LNG loading facility, and supporting infrastructure. The project is due to start up by mid-2020.

In 2018, Inpex Masela Ltd let a pre-FEED contract to KBR for the Abadi LNG project in eastern Indonesia, based on an onshore LNG development scheme with an annual LNG production capacity of 9.5 MTPA, liquefying natural gas from the offshore Abadi field. Initially being evaluated as an offshore floating LNG development, in 2016, the Indonesian authorities instructed Inpex to re-propose the development for the Abadi LNG Project based on an onshore LNG development scheme. The field is in 400-800 m of water in the Arafura Sea, 150 km offshore to an onshore location, on either Aru or Saumlaki Island.

Malaysia

Petronas' PFLNG-1 Satu, the world's first operational FLNG, reached its final stages of commissioning and start up with the introduction of gas from the Kanowit gas field in November 2016, with its first cargo in the first quarter of 2017, raising Malaysia's LNG production capacity by 1.2 MTPA.

Construction of Petronas' second floating LNG facility, PFLNG-2 Dua, is underway and is to be installed on the Murphy-operated Rotan field 240 kilometres off Sabah. PFLNG Dua will boost Malaysia's total production capacity of LNG by another 1.5 MTPA. Petronas says second floating LNG facility to be operational in 2020.

Tongyeong Terminal - Courtesy of KOGAS

Looking Ahead

Will liquefaction investment activity remain muted in 2019?

LNG Canada is the first greenfield LNG export project to take FID in five years, since Yamal LNG in 2013. A clutch of projects are vying for FID in 2019, including four mega trains in Qatar, Arctic LNG-2 in Russia, at least one development in Mozambique and several US projects. 2019 could be the busiest for LNG FIDs in many years.

Many projects are seeking to reach an FID in 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, particularly if suppliers show a willingness to invest without contracts.

Is a significant LNG surplus still expected?

Construction delays and slow ramp-ups at some projects reduced supply in 2018. 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 mid-2020s.

Two camps have emerged within the LNG market and their views are polar. The oversupply group argues that LNG supply will outpace demand growth over 2018 to 2021, while the tight market group sees little evidence of oversupply, given demand growth is broadly keeping pace with new liquefaction projects coming online. The latter also points to a shortage of gas in the early 2020s due to a lack of investment now and that growing gas demand from Asia, particularly from China, could swing the liquefied natural gas (LNG) market into a deficit by 2022-2025.

Market expectations of oversupply and weak gas prices have curtailed new investment activity in the sector in the past four years. An unprecedented wave of new projects becoming operational in 2014 to 2019 has not resulted in, and is unlikely to, result in a material surplus in the LNG market in the medium term. These additional LNG volumes continue to find a home across a diverse array of markets and new buyers, and under more flexible contracts.

Funding for new LNG capacity is often structured as non-recourse project finance and is dependent on sponsors' ability to secure long-term offtake agreements, which buyers have been less willing to sign in anticipation of larger volumes of uncontracted LNG coming to the market. Therefore, sponsors may need to commit a higher equity contribution to get funding for LNG projects, which will continue to delay FIDs for some time. A typical timeframe for a new LNG project to become operational following the FID is four to five years. Due to limited new FIDs, very few new projects will come on stream in the early 2020s. FIDs in the next one to two years are likely to be limited to projects with lower capital and operating costs given constraints on the funding side.

It is expected that gas demand will continue its robust growth in the coming years, mostly driven by Asian markets that account for two-thirds of overall LNG demand. This is due a combination of healthy power demand growth in the region, natural gas being the fossil fuel of choice in pursuit of curbing air pollution, and the backlash against nuclear energy. Japan is currently the largest LNG importer, but China is catching up quickly and becoming the major market for LNG.

Gas pricing is improving in the major importer markets, benefiting LNG projects relying on spot and hub pricing and entities with significant LNG trading portfolios.

Oil majors are also gradually returning to their earlier LNG ambitions, including Shell, BP, Total and ExxonMobil, most of whom emphasise the growing role of gas in the global energy mix.

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. This was followed by Kribi FLNG offshore Cameroon which began LNG commercial production in May 2018. One other FLNG project, Shell's Prelude, will commence LNG exports early 2019.

The future of near-shore FLNG technology is looking more positive with the news that Exmar's 0.5 MTPA Caribbean FLNG barge (now called Tango FLNG) has been chartered by Argentina-based firm YPF under a ten-year agreement, and it is expected to start up LNG production in the second quarter of 2019. Under the deal, Exmar's FLNG barge will produce and export LNG from the Vaca Muerta source at the Neuquén Basin in Argentina. The project marks the market's entry to the club of global LNG exporting nations, with an initial plan to export 0.5MTPA to overseas markets. Up to eight LNG cargoes per year are expected to be produced over the ten-year period. The vessel was delivered by Chinese shipyard Wison in July last year and was originally intended to be used nearshore Colombia, South America, however that agreement was terminated in March 2016. In 2017 it was reported that Exmar was in talks to deploy the unit for an Iranian export project to process gas from offshore oilfields near Kharg Island, but the agreement was not approved by the government.

Another FLNG project in development is the BP led Greater Tortue project offshore Senegal and Mauritania. This project is detailed above under West Africa.

The market will be watching how these FLNG facilities ramp up to assess the initial performance of the various development concepts and the overall longer-term potential of FLNG. Several FLNG projects are planned to utilize a similar conversion design to Kribi 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.

5. LNG Carriers

525
LNG Vessels
At end-2018

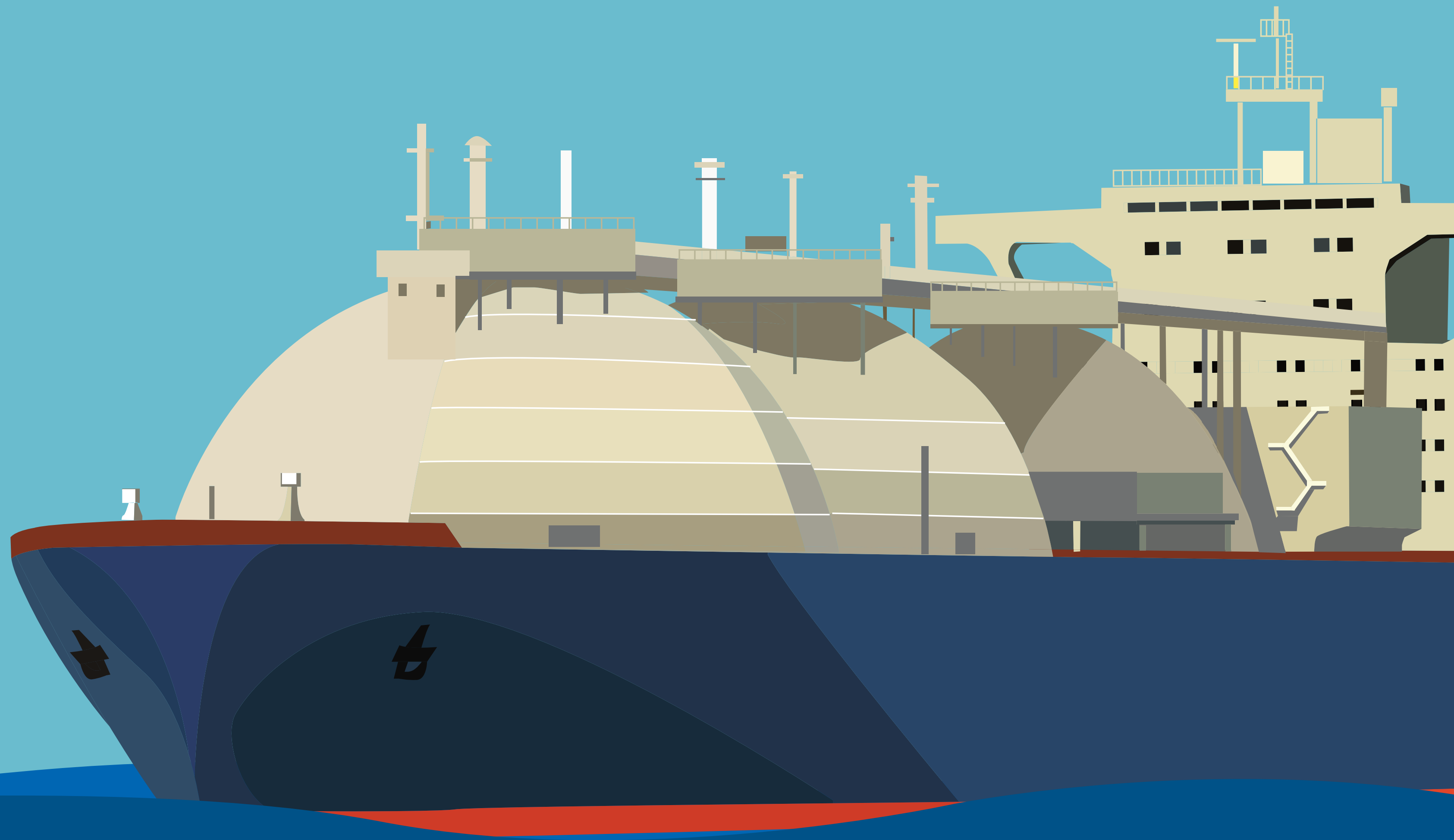
5,119
Trade voyages
In 2018

Spot charter rates for a modern fuel-efficient tanker averaged $76,000/day for the first two months of the year, an **81%** YOY increase

Spot charter rates tapered off during the spring and summer months, averaging **$56,000/day**

Spot charter rates in Q4 2018 peaked at an all-time high of **$195,500/day** and averaged **$150,000/day**

This was short-lived and spot charter rates had returned to around **$74,000/day** by January 2019



Global LNG Fleet

+53
Conventional carriers added to the global fleet in 2018

Propulsion systems

41%
Active vessels with DFDE/TFDE, ME-GI, or XDF propulsion systems

Charter Market

Steam $53,400
TFDE/DFDE $85,500
Average spot charter rate per day in 2018

Orderbook Growth

+52
Conventional carriers ordered in 2017

The LNG shipping sector has evolved over the past decade in response to substantial changes in the broader LNG market. The market has been cyclical in nature, with charter rates falling from historic highs in 2012 when the Fukushima disaster in Japan caused a spike in the need for spot deliveries, to historic lows in the summer of 2017 owing to the lingering effects of a large buildup in shipping tonnage experienced since 2013.

New deliveries matched additions in LNG supply in 2018 more evenly, and rates were supported by an increase in winter LNG demand in China. Spot charter rates for a modern fuel-efficient tanker averaged $76,000/day during the first two months of the year, an 81% YOY increase. While spot charter rates tapered off during the spring and summer months, averaging around $56,000/day, they were still significantly higher than the levels of 2017.

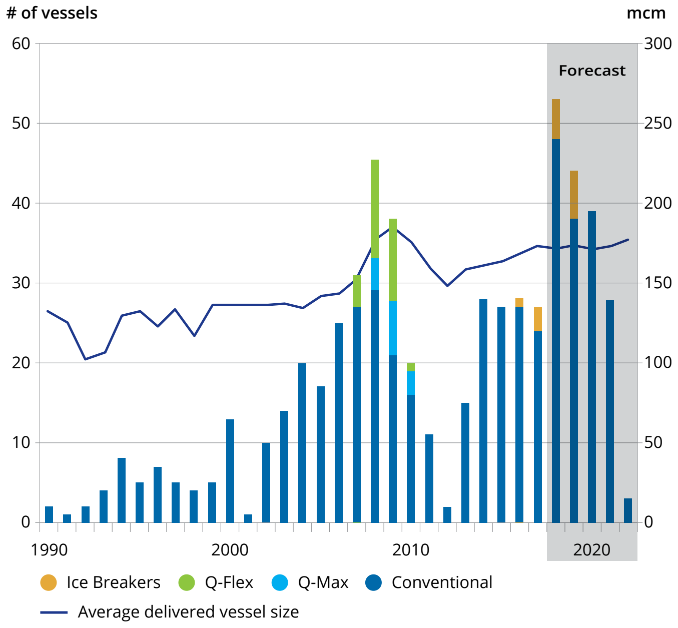
Notably, toward the end of 2018 there was a significant uptick in charter rates owing to the buildup of winter LNG inventories in Northeast Asian markets. This rate increase was further bolstered by a resulting floating storage play as inventory levels maxed out in Northeast Asia, resulting in laden tankers with postponed discharge dates. Spot charter rates in Q4 2018 peaked at an all-time high of $195,500/day and averaged $150,000/day. However, this was short-lived and spot charter rates had already returned to around $74,000/day by January 2019. Still, even with the decline from end-2018 it is unlikely that charter rates will return to their 2017 levels as 51.8 MTPA of new liquefaction capacity is expected to start up in 2019, which will help keep rates higher. This liquefaction capacity will be met by only 43 newbuild deliveries. Given the historical rubric of one tanker for 0.75 MTPA or 1.2-1.3 vessels per 1 MTPA of liquefaction capacity, there is a high probability that rates will stay high as shipping capacity struggles to match new LNG exports.

LNG Carrier Pyeongtaek - Courtesy of KOGAS

5.1 OVERVIEW

There were a total of 525 vessels in the LNG fleet by the end of 2018, including those vessels actively trading, sitting idle available for work, and acting as FSRUs.[1] Of the total global LNG fleet, there are 31 FSRUs and five floating storage units. The overall global LNG fleet grew by 11.5% in 2018, as 53 carriers were added to the fleet (see Figure 5.1), including four FSRUs. The global LNG fleet growth was matched by 26.2 MTPA of new liquefaction capacity in 2018.

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

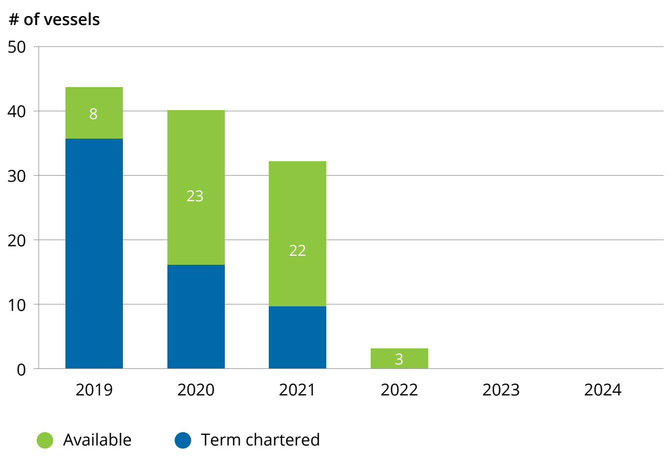
The shipping market continued to add new tonnage in 2018, continuing a pattern of growth established in early 2013 with speculative newbuild orders. However, as the growth in new liquefaction capacity catches up to new vessel deliveries, the dampening effect that the large buildout has had on charter rates since 2013 should ease.

525 vessels
Number of LNG vessels (including chartered FSRUs) at end-2018

Average storage capacity at LNG carriers has also increased over the years, supported by a push to capture economies of scale and build ever-larger vessels in the early 2010s, reflected in the buildout of the Qatari Q-Max and Q-Flex fleet. More recently, the newbuild deliveries and newbuild orders seen during 2018 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 upper limits for the new Panama Canal expansion. However, in 2018, Korean yards introduced a new Neopanamax design for an LNG carrier with a capacity of 200,000 cm. The average LNG storage capacity for a newbuild delivered during 2018 was a little above 171,000 cm.

At the end of 2018, the LNG vessel orderbook contained 118 carriers expected to be delivered through 2022, 59 of which were ordered during the year; a 195% increase from 2017.[2] The large jump in newbuild orders is caused both by LNG offtakers ordering ships for new liquefaction capacity and speculative orders by shipowners. There was a slowdown in project FIDs being reached in 2016-2018, which also 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 2018, around 52% of the orderbook was tied to a specific project or charterer, leaving 56 carriers available for the spot market or to be chartered out on term business (see Figure 5.2).

Figure 5.2: Estimated Future Conventional Vessel Deliveries, 2018-2024



Note: Available = currently open for charter. Data represents the order book as of end-2018.
Source: IHS Markit

[1] For the purposes of this report, only LNG vessels with a capacity greater than 30,000 cm are considered part of the global fleet and included in this analysis. All vessels below 30,000 cm are considered small-scale.
[2] As with existing vessels, only LNG vessels with a capacity greater than 30,000 cm are included in the analysis of the order book. All vessels below 30,000 cm are considered small-scale.

LNG Carrier Pyeongtaek - Courtesy of KOGAS

An additional 43 carriers (including 4 FSRUs) are expected to be delivered from the shipyards in 2019, while another 51.8 MTPA of new liquefaction capacity is targeted to start up. After 2019, the buildout of the 49.5 MTPA of LNG liquefaction capacity currently under construction will be mostly aligned with expected deliveries from shipyards. The market could even potentially move towards a situation of under-supply when the retirement or conversion of older steam carriers is taken into consideration.

The Panama Canal has continued to play a significant role in 2018, as exports from Sabine Pass, Cove Point, and Atlantic LNG have turned toward Asian markets in search of higher returns. Transit through the canal allows offtakers from those projects to access Asia-Pacific and Asian markets in only 22 days, as opposed to 35 days via the Suez Canal or Cape of Good Hope. A total of 12.6 MT of LNG made the transit through the Panama Canal in 2018. This was composed of 190 laden voyages through the Panama Canal, of which Sabine Pass accounted for 77%. When compared to 2017, the number of laden voyages through the Panama Canal increased by 78%. For the better part of 2018, there was a substantial price spread between the Pacific and Atlantic Basin, resulting in an increase in cross-basin trade. Of the 190 laden transits through the Panama Canal, 134 were destined for Asia-Pacific and Asian markets, 46 for Latin America, and the remaining 10 were Peru LNG cargoes destined for the European market. Initial constraints associated with the new Panama Canal expansion limited laden LNG transits to one per day, but these constraints have since been removed and the Panama Canal is now consistently accommodating three laden tankers per day. However, while the Panama Canal has reduced the shipping distance between the United States and Asia, the Canal will not be able to accommodate the sheer amount of US liquefaction capacity expected to come online over the next few years, meaning that the average length of LNG voyages will likely increase depending on how much US LNG supply flows to Asia.

After the first floating liquefaction project started up in 2017, the sector continued to evolve in 2018 with the start-up of a second project. The purpose-built PFLNG Satu unit sent out its first cargo in April 2017, and the unit is slowly ramping up production with seven cargoes delivered throughout the year. The converted floating liquefaction unit *Hilli Episeyo* was delivered in October 2017, and arrived on site in Cameroon for the Kribi FLNG project in November 2017. The first Kribi FLNG cargo was loaded on May 2018 and exported a total of 0.62 MMT throughout 2018. The sector will continue to expand with a third project in 2019; 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. The first cargo is expected in Q1 of 2019. For further information, see Chapter 9: Floating LNG.

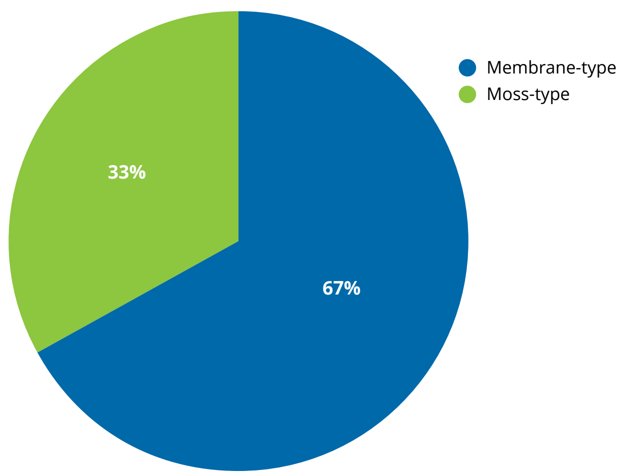
5.2 VESSEL CHARACTERISTICS

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 already been implemented on board of LNG carriers for many years now and other designs from different companies have recently been developed. GTT recently developed new solutions to reduce boil-off rates to around 0.07% of a cargo during transit. Among these new systems, the Mark III Flex +, Mark V, and NO96 Flex 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 2018, 67% 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. The Sayaringo LNG carrier was developed by Mitsubishi and was purpose built for the long haul voyages between the US and Japan.

Both tank systems rely on expensive insulation to keep LNG cold during the voyage and minimize evaporation. Nevertheless, an amount equivalent up to roughly 0.15% of the cargo evaporates per day in older designs. 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%. The Japan Marine United shipyard has achieved this low boil-off rate as well as reduced sloshing with the IHI SPB containment system. They delivered one LNG carrier with this containment system in 2018 and have another three on order.

Figure 5.3: Existing Fleet by Containment Type, end-2018



Source: IHS Markit

Propulsion Systems

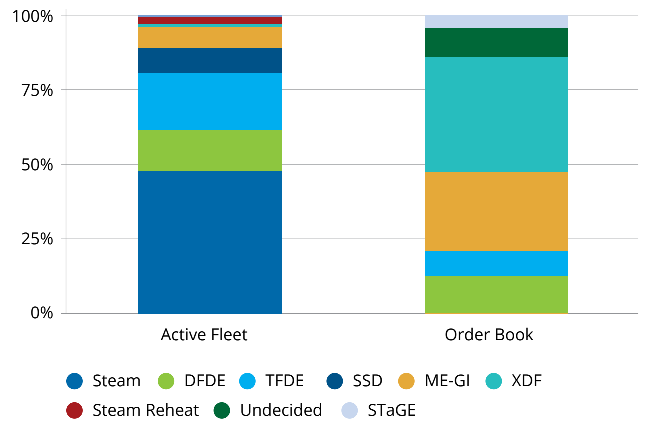
To keep the tank pressure close to atmospheric conditions per design conditions for Moss and membrane systems, BOG has to be taken out from the tanks, and has generally been used for fuelling the ships' steam-turbine propulsion systems, which are reliable but not the most efficient. Since the early 2000s, 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 even 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 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.

Figure 5.4: Existing and On Order LNG Fleet by Propulsion Type, end-2018



Source: IHS Markit

[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, ENGIE (then GDF SUEZ) 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 32% of active vessels in 2018 were equipped with DFDE/TFDE propulsion systems. Additionally, the orderbook consists of 22% of vessels planned with DFDE/TFDE systems as of end-2018 (see Figure 5.4).

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: Fearnleys, IHS Markit

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.

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)
As of end-2018, around 27% 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. As of end-2018, there are 36 carriers in the global LNG fleet utilising this propulsion system, 21 of which were delivered in 2018. The share of carriers utilising the ME-GI system is expected to continue to grow substantially in 2019, as another 17 such carriers are expected to be delivered during the year.

Winterthur Gas & Diesel (WinGD) Low-Pressure Two-Stroke Engine (XDF)
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 (NO_X) abatement systems may not be required. By end-2018 there were 6 active tankers utilising the XDF propulsion system, with 44 XDF tankers on the orderbook.

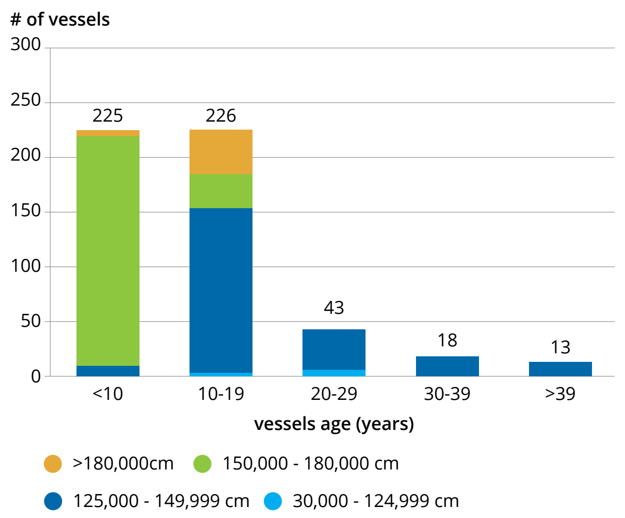
Steam Reheat and STaGE
In order to improve the performance of a traditional steam-turbine propulsion system, modern designs have been developed. The Steam Reheat design is based on a reheat cycle, where the steam used in the turbine is reheated to improve its efficiency. The STaGE system combines steam turbines and gas engines equipped with waste heat recovery. These improvements in steam adaptation have maintained the benefits of the simple steam-turbine while improving overall efficiency.

Vessel Size

The size of an LNG vessel can vary widely depending on age and need. 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-2018, 43% of active LNG carriers had a capacity within this range. However, vessels with a capacity of between 150,200 cm and 180,000 accounted for 46% of the market by end-2018, making that range the new most common vessel size in the existing fleet (see Figure 5.5). Conventional carrier newbuilds delivered during 2018 had an average size of 171,500 cm, and none of the 48 vessels had a capacity lower than 150,200 cm.

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 9% of the active fleet and 12% of total LNG transportation capacity at the end of 2018.

Figure 5.5: Active Global LNG Fleet by Capacity and Age, end-2018



Source: IHS Markit

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 a larger carrier from the US LNG trade. As of end-2018, 91% 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 2018, 51% of the active fleet was 10 years of age or younger, a reflection of the newbuild order boom that accompanied liquefaction capacity growth in the mid-2000s, and again in the early 2010s. Generally, shipowners primarily consider safety and operating economics when deciding whether to retire a vessel after it reaches the age of 35, although some vessels have operated for approximately 40 years. Around 6% of active LNG carriers were 30 years of age or older by the end of 2018; 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, those vessels can still re-enter the market. At the end of 2018, 19 vessels (primarily Moss-type steam carriers, all with a capacity of under 150,000 cm) were laid-up. Over 83% of these vessels were over 30 years old, and all were older than 10. A total of 7 tankers were either scrapped or scheduled to be scrapped during 2018, with the average age being 40 years old.

As 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 2018, one vessel was nominated for conversion to an FSRU; the 14-year-old, steam propelled, 140,000 cm *Golar Viking* will be delivered to the Croatia LNG project in 2020. One problem that potential conversion candidates are running into is size, as most modern LNG FPSO, 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.

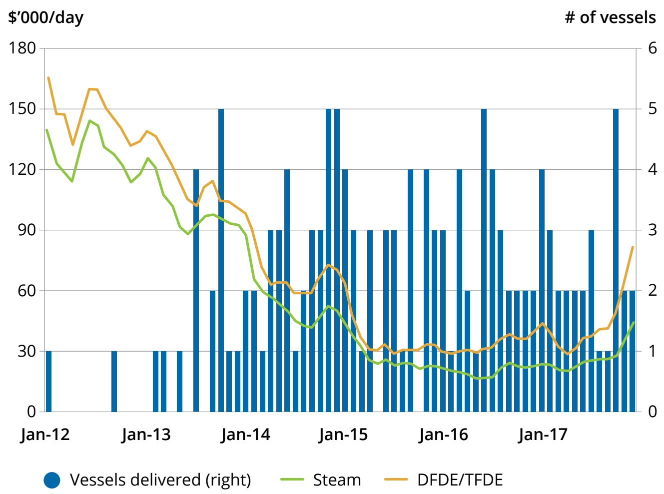
Global LNG Fleet	Propulsion systems	Charter Market	Orderbook Growth
53 Conventional carriers added to the global fleet in 2018	**41%** Active vessels with DFDE/TFDE, ME-GI, or XDF propulsion systems	**Steam $53,400** **TFDE/DFDE $85,500** Average spot charter rate per day in 2018	**59** Conventional carriers ordered in 2018
The active fleet expanded to 525 conventional carriers in 2018. The average ship capacity of newbuilds in 2018 was 171,500 cm, a slight decrease compared to 2017. Four FSRUs were also completed in 2018, plus one floating storage unit.	In 2015, over 72% of the fleet was steam-based; by 2018, this had fallen to 47%. The orderbook has a variety of vessels with new propulsion systems, including ME-GI and XDF, which together account for 64% of the vessels on order.	After three years of low charter rates, delivery of vessels more evenly matched new LNG supply, propping up rates in 2018. Rates spiked to an all-time high in Q4 2018, peaking at $195,500/day for modern fuel-efficient tonnage due to high Asian LNG demand.	After a multi-year lull in new orders, additions to the orderbook increased by 195% in 2018. Two FSRUs were also ordered in 2018. Nearly three-quarters of the orders placed in 2018 were speculative.

[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 180,000cm, but there is no specific limitation on capacity.

5.3 CHARTER MARKET

In 2018, spot charter rates averaged $53,000/day for conventional steam tankers, and $85,000/day for modern fuel-efficient tankers (DFDE, TFDE, ME-GI, X-DF). However, for the first three quarters of 2018, rates for a modern fuel-efficient tanker averaged only $63,000. The surge in spot charter rates during Q4 2018 skewed the annual average, with rates reaching a historic peak of $195,000/day. This rate increase was spurred by the build-up of winter inventories in Asia, and ultimately the floating storage play that ensued as inventories filled up quicker than expected, delaying discharge windows. During this Q4 increase in spot charter rates, Europe had its highest-ever single month of LNG imports as the rise in freight costs made voyages to Asian markets less desirable to traders with Atlantic Basin cargoes. For traders without their own dedicated fleet that needed to charter tankers off the spot market, the high cost of cross-basin trades led them to turn to Europe as netbacks were more favourable. However, these historically high rates were short-lived as the market worked through the floating storage volumes; in the first month of 2019, rates fell back down to around $74,000/day.

Figure 5.6: Average LNG Spot Charter Rates versus Vessel Deliveries, 2012–2018



Source: IHS Markit

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 325 spot fixtures during 2018, a 12% YOY decrease as there was very little tanker availability in Q4 due to the winter inventory build-up and floating storage play. The bulk of spot fixtures were for DFDE/TFDE carriers; this is further evidence of the market's preference for the newer, larger, and more fuel efficient ME-GI, and XDF carriers as most of those vessels have already been contracted under long-term charter.

As LNG prices face downward pressure and in turn squeeze trading margins, charterers are trying to reduce costs where they can. 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 larger savings overall when boil-off and fuel consumption are taken into consideration. A few of 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, but the majority have been contracted under long-term charters. As the DFDE/TFDE, ME-GI, and XDF 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 2019, rates are expected to fall off their winter highs as the market enters the shoulder months for LNG demand. However, the continued buildout of liquefaction capacity should prevent a return to the lows reached in 2017. The 51.8 MTPA of new liquefaction capacity coming online in 2019 is currently being met by only 41 newbuild deliveries. This is slightly mismatched, as with current trading dynamics one LNG tanker is needed for every 0.75 MTPA of liquefaction capacity.

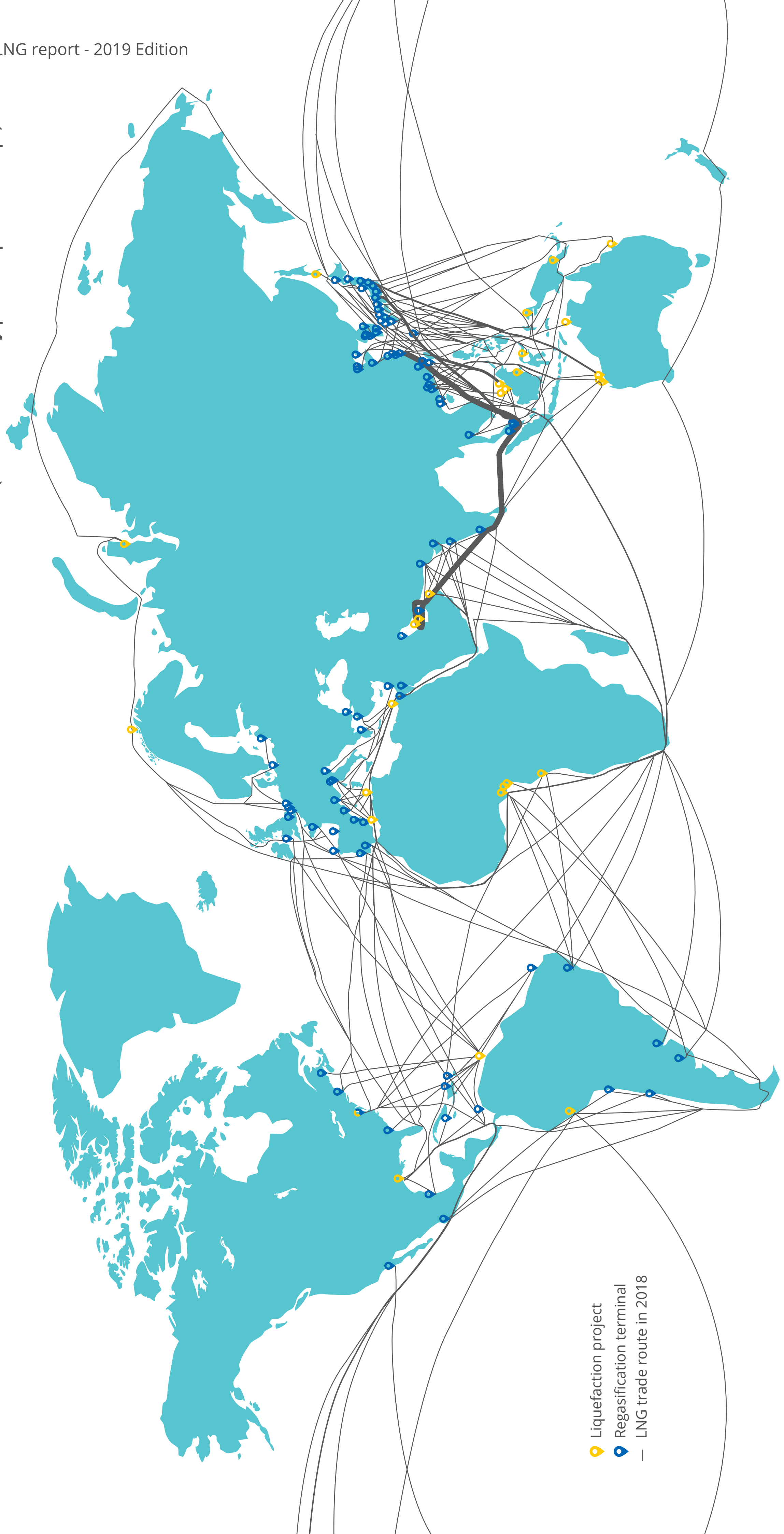
Pacific Breeze - Courtesy of Inpex

Figure 5.7: Major LNG Shipping Routes, 2018

Longest LNG voyages length in 2018:
15,520 nm
(Sabine Pass LNG to Japan via Cape of Good Hope)

Number of LNG voyages in 2018:
5,119

Shortest LNG voyage length in 2018:
130nm (Algeria to Spain)



Source: IHS Markit

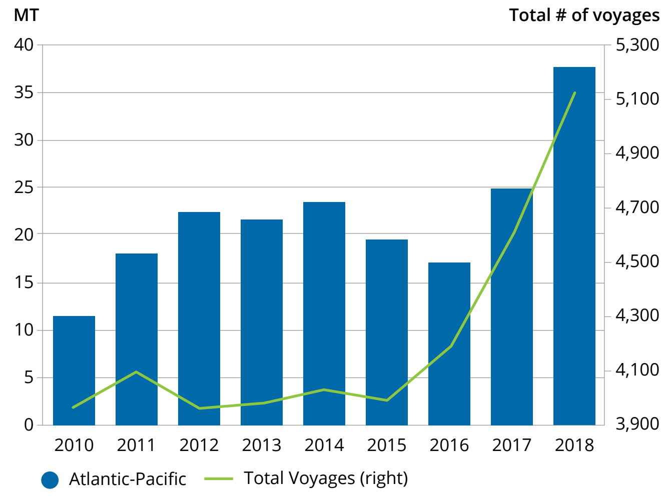
5.4 FLEET VOYAGES AND VESSEL UTILISATION

Once again, the total number of voyages completed in 2018 grew, as both Asian and European markets helped to absorb new supply from the continued build-out of new liquefaction capacity. A total of 5,119 voyages were completed during the year, an 8% YOY increase (see Figure 5.8). Historically, trade was most commonly conducted on a regional basis along fixed routes serving long-term point-to-point contracts, though the rapid expansion in LNG trade over the past decade has been accompanied by an increasing diversification of trade routes. With new liquefaction capacity coming online in the US and the Panama Canal expansion accommodating more LNG tankers, inter-basin trade was on the rise in 2018, at 13% YOY.

5,119 Voyages
Number of voyages of
LNG trade voyages in 2018

With the Panama Canal expansion now operational for over two years and daily slots for LNG tankers increasing, the voyage distance from the US Gulf Coast to Japan has been reduced to 9,500 nautical miles (nm), compared to 14,400 nm when the Suez Canal is used. The longest voyage undertaken in 2018 was from Sabine Pass LNG to Sakai, Japan around the Cape of Good Hope – a distance of 15,520 nm, with the shortest voyage being a more traditional route from Algeria to Spain, at 130 nm. The most common voyage in 2018 was from Australia to Japan, with 469 voyages completed during the year.

Figure 5.8: Atlantic-Pacific Trade versus Total Number of Voyages per year, 2010-2018

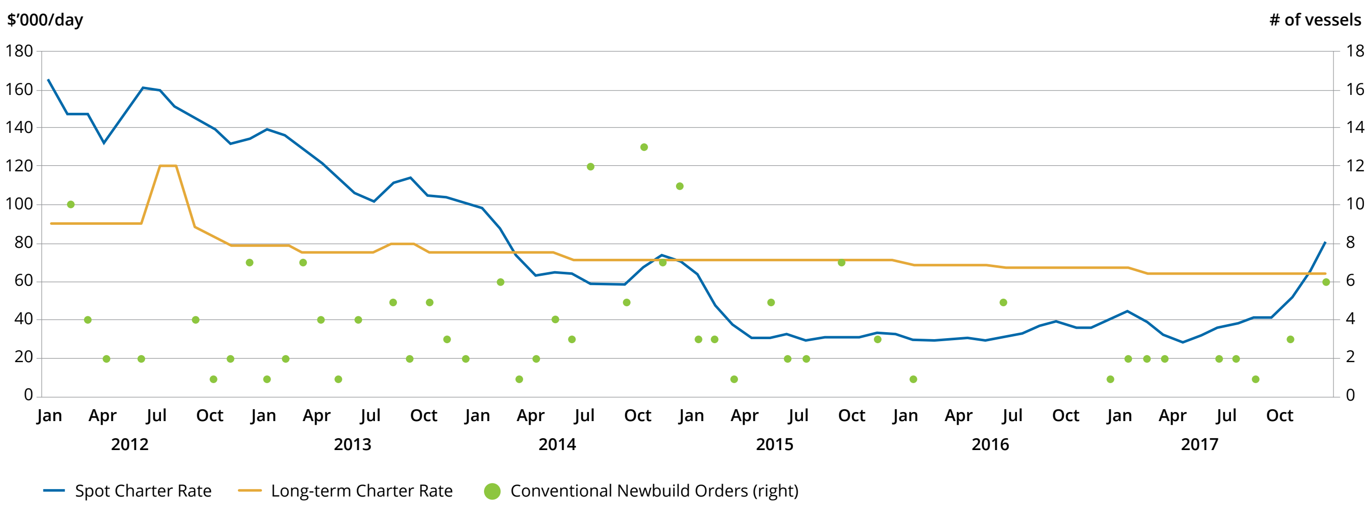


Source: IHS Markit

In 2018, the average number of voyages completed per tanker was 10.5, compared to the 11 voyages per tanker in 2017. Laden voyage days were up in 2018, averaging 14 days compared to 13 days in 2017. This corresponds with the increase in cross-basin trade – the longer voyage distance results in fewer completed voyages. Even with the buildout in new liquefaction capacity in 2018, the holdover from outmatched deliveries in previous 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.

Rita Andrea - Courtesy of Shell

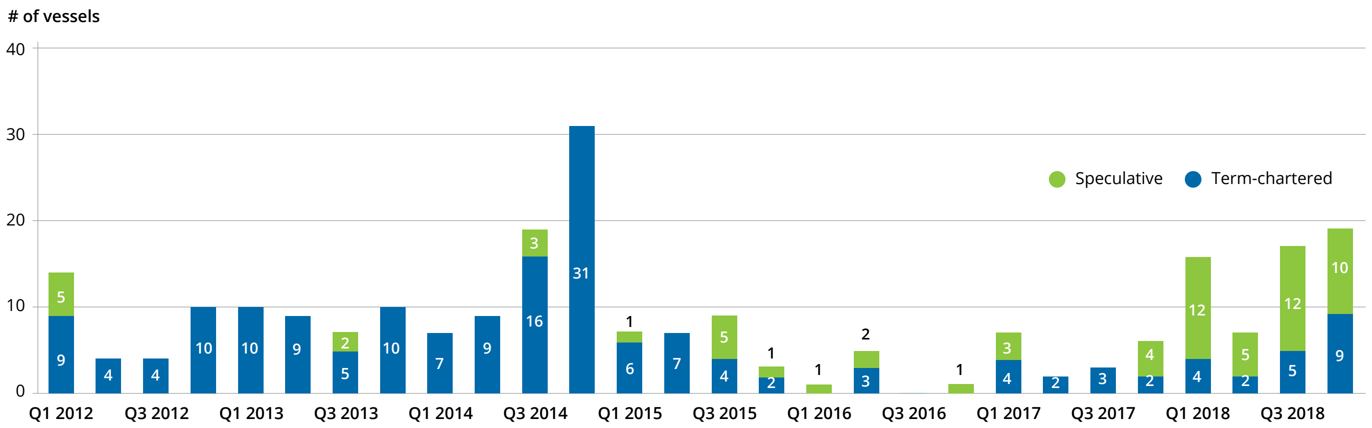
Figure 5.9: Estimated Long-term and Spot Charter Rates versus Newbuild Orders, 2012-2018[5]



Source: IHS Markit

Starting in 2013, the build-up in LNG liquefaction capacity lagged the influx of newbuilds to the market, creating high carrier availability and low charter rates, though 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. A continued influx of new tonnage through 2017 kept rates low and led them to hit an all-time trough in the spring of 2017. However, starting in the 2017-2018 winter, demand for spot tonnage was heightened by China's appetite for spot LNG volumes as they progressed coal-to-gas switching plans, causing spot charter rates to rise to levels not reached since early 2014. While there was a slight rate correction as the market exited the coldest winter months, rates stayed elevated throughout the first half of 2018. Toward the end of 2018, rates began to soar owing to the buildup of winter LNG inventories in Northeast Asian markets, further bolstered by a resulting floating storage play as inventory levels maxed out in Northeast Asia. This resulted in laden tankers with postponed discharge dates. Spot charter rates in Q4 2018 peaked at an all-time high $195,500/day and averaged $150,000/day. However, this was short-lived and spot charter rates had already returned to around $74,000/day by January 2019.

Figure 5.10: Firm Conventional Newbuild Orders by Quarter, 2012-2018



Sources: IHS Markit, Shipyard Reports

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

5.5 FLEET AND NEWBUILD ORDERS

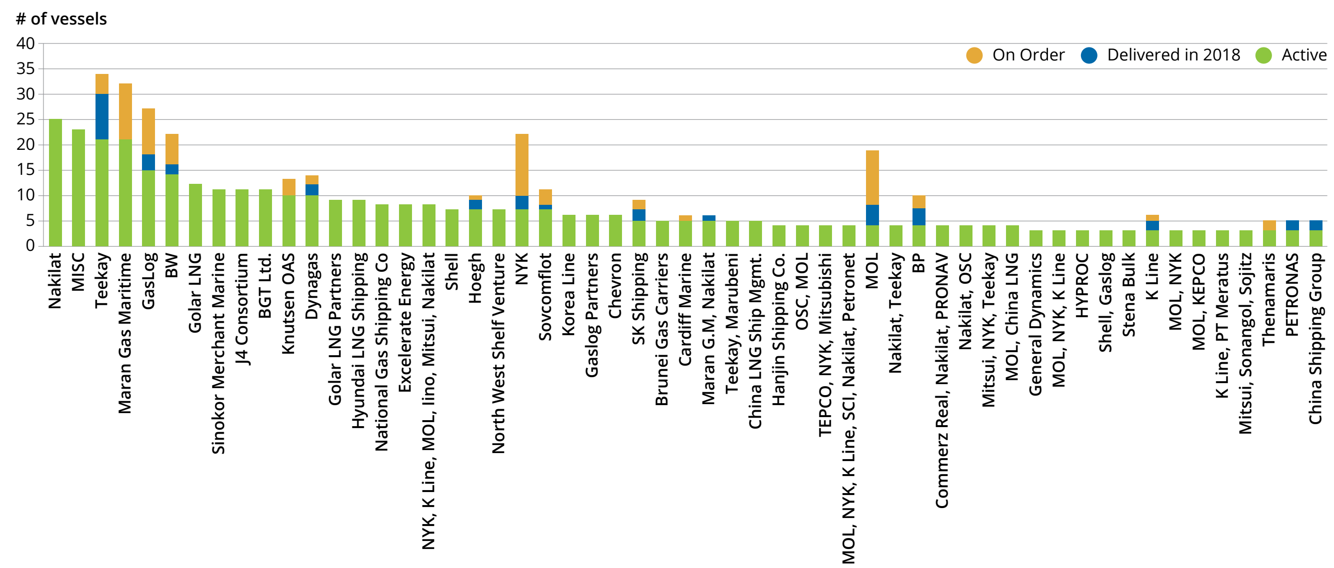
At the end of 2018, 118 vessels were on order. Around 52% of vessels in the orderbook were associated with charters that extend beyond a year, while 56 vessels were ordered on a speculative basis (see Figure 5.10).

In 2018, newbuild vessel orders increased by 195% YOY to 59, two of which were for FSRUs. Prior to 2017, the slowdown in liquefaction FIDs had also led to a lull in new vessel orders, as companies delayed a decision on potential associated 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, as the lull in new orders stretched into years, the potential for a tighter shipping market began to loom, particularly considering the propensity to favour more fuel-efficient DFDE/TFDE, ME-GI, and XDF carriers over steam turbine carriers. Newbuild orders began to increase in mid-2017 and this trend continued into 2018, especially as the first generation of LNG carriers are being considered as potential scrap or conversion candidates. The potential of a tightening shipping market post-2022 will keep the momentum in the newbuild market going into 2019, as a series of newbuild orders and options have already been taken by LNG shipowners in the first month of the year.

Many independent shipping companies made moves to dramatically grow their fleet sizes in the aftermath of the Fukushima nuclear crisis. The more traditional LNG shipowners have typically ordered newbuilds on the back of a long-term contract, leaving the speculative orders to the more niche owners. However, as with the growth of traditional buyers and sellers in the spot LNG trading market, traditional shipowners are also increasingly branching out into speculative orders.

Out of the 118 vessels on charter in the order book, 22% 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 35% of the new-build orders as the companies gear up for their Australian and US offtake. The remaining charters are from companies with multiple market strategies, including traders and aggregators.

Figure 5.11: LNG Fleet by Respective Interests, end-2018



Note: The above graph only includes shipping groups that have three or more active vessels.
Source: IHS Markit

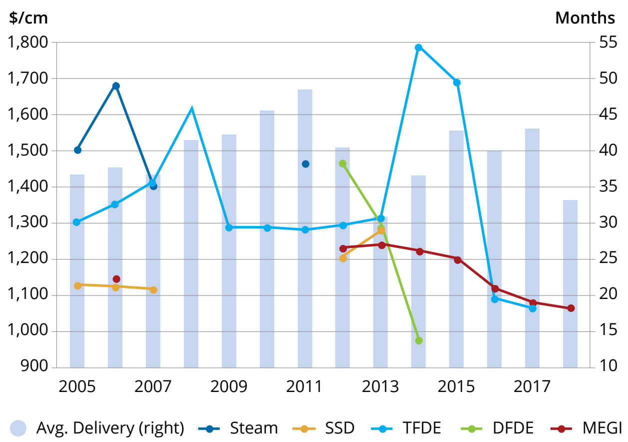
5.6 VESSEL COSTS AND DELIVERY SCHEDULE

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 XDF/ME-GI vessels dropped back to $1,057/cm. 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. Following a banner year for LNG newbuild orders in 2018, vessel costs have ticked upwards to $1,069/cm.

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 lengthened 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 this 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, all of which have already been ordered; 9 vessels have been delivered as of the end of 2018. 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. In December 2017, the first of these vessels loaded at the Yamal LNG project.

Figure 5.12: Average Delivery and Cost per Cubic Meter in Ordered Year by LNG Carrier Type, 2005-2018



Source: IHS Markit

Sakhalin Energy Grand Aniva - Courtesy of Shell

5.7 NEAR-TERM SHIPPING DEVELOPMENTS

Currently, 84% of global shipping uses heavy fuel oil that generates polluting sulphur dioxide. Shipping companies increasingly must consider local and global regulations for air emission pollution, among other developments.

In the maritime industry, IMO has a clear route to implement regulations to reduce Sulphur Oxides (SOx) and NOx in the near-term, and further reduce CO2 emissions in the long-term. In addition, regulatory bodies from states such as California (CARB), markets such as the EU, and markets such as China, Hong Kong and others have also issued specific regulations to limit the use of fuels with high content of sulphur. The most important global regulation is the IMO sulphur cap (0.5% maximum content) which will affect the global fleet starting in 2020. In emission control areas and in EU ports, this threshold is further reduced to 0.1% maximum content.

In particular for SOx compliance, the sulphur content of LNG is 1000 times lower than the IMO's 0.5% rule. Beside the use of low sulphur fuels, other alternative methods have been proposed such as exhaust gas treatment systems, called scrubbers. Nevertheless, some authorities have decided to ban the use of open loop scrubbers, equipment which uses sea water in an open loop as a method to clean the exhaust gas. Although the investment to install LNG fuel equipment on board may be significant compared to scrubber installation, LNG fuel might be a more convenient and economical solution in the long term. This may become an increasingly important consideration for shipping companies when developing their fleet in the future.

In addition to the above regulations in place for ships, environmental advantages of LNG as a fuel create a business case for the development of new LNG import terminals.

This has resulted in two clear trends in the LNG market. Firstly, the increased use of LNG as fuel for more ships, which had already been used traditionally for LNG carriers. Secondly, the implementation of fast regasification and trucked LNG to power solutions by means of floating storage units, floating storage and regasification units (FSRU's) and combinations of both.

The fleet of LNG fuelled ships, other than gas carriers, has grown sustainably in the last years. More than 150 ships are now in service and many more on order. Although the bunker capacity of the ships is relatively small, a fleet of small scale carriers dedicated to bunkering LNG has rapidly developed. As indicated in Chapter 8: Small-scale focus on LNG bunkering, 7 ships are already providing LNG as a bunker fuel in Europe and one barge has recently been delivered in the USA. Many more LNG bunkering ships are on order, so potentially by 2022 more than 20 ships could be in operation globally. Regions identified where those ships could deploy are the USA and Canada, Europe and large bunkering ports in the world such as Singapore.

The second main trend is the development of new business models; including floating installations to import LNG and feed gas to power plants. Multiple configurations of new terminals involving FSRU's or floating storage units have been implemented. Examples in the last years are the Malta and Jamaica floating storage unit import terminals. Although the concept is different the purpose is the same - to burn cleaner energy in power plants on shore. The Maltese power plant receives LNG by cryogenic pipe and then burns the natural gas once it is regasified on shore. The Jamaica project is a bit more complex, involving trans-shipment from the floating storage unit to a small-scale LNG carrier that delivers the parcels to a regas and power plant facility. Short term new developments may include floating gas power plants moored alongside or in the proximity of FSRU's. Different concepts for barges, both newbuild and conversions, have been proposed. Eventually, FSRPU (floating storage regasification and power units) have been designed.

More specifically for LNG carriers, the market has become very dynamic for different reasons. The main reason has been the high requirements for flexibility in LNG trade. For instance, ships are delivering more and more partial cargoes. This means that in some cases, only some cargo tanks would be offloaded at the receiving terminal, and the rest would be shipped to another destination. Many more small-scale developments are expected, thereby creating additional requirements for small LNG carriers.

LNG shipping will follow the same trend, and will look to become even more flexible. Technologies applied for ships will have to follow the charterers and owners' requirements. Containment system boil off rates and propulsion engines consumption will be aligned as much as possible, and ships speed reduced to 15-16 knots in more cases. Re-liquefaction technologies will be installed on board and new systems developed. In the short term, new containment systems for small scale ships will be developed as well.

6. LNG Receiving Terminals

Global LNG regasification capacity reached a high of
824 MTPA
as of February 2019

New terminals and expansion projects added
22.8 MTPA
of regasification capacity to the global LNG market in 2018

+6.2 MTPA
Net growth of global LNG receiving capacity

+5
New LNG onshore import terminals

+2
New LNG Offshore terminals

+2
Regasification markets

Argentina, Brazil, Egypt, and United Arab Emirates
had their chartered FSRUs leave port in 2018 removing 16.6 MTPA from the market and resulting in only 6.2 MTPA of net regasification capacity growth.

New markets including
Bahrain, Croatia, El Salvador, Ghana, and the Philippines
are in the process of constructing their first regasification terminals

Multiple new regasification terminals and expansion projects were set to begin operations in early 2019, including
Thailand, India, Chinese Taipei, China, Jamaica, Russia (Kaliningrad), Bahrain, and Bangladesh

China
was a particular source of growth, completing three new terminals in 2018 and an expansion of an existing terminal.

Global LNG regasification capacity reached a high of 824 MTPA[1] as of February 2019, continuing a path of consistent expansion. While the growth in regasification capacity was primarily centred in existing LNG markets, two new LNG importers – Bangladesh and Panama – added regasification capacity in 2018 as the first new importers to the market since 2016. In addition, China, Japan, and Turkey also added new terminals during the year.

China was a particular source of growth, completing three new terminals in 2018 and an expansion of an existing terminal. A regasification capacity expansion was also completed in Greece. In sum, new terminals and expansion projects added 22.8 MTPA of regasification capacity to the global LNG market in 2018[2]. However, four terminals – in Argentina, Brazil, Egypt, and United Arab Emirates – had their chartered FSRUs leave port in 2018 as their services were no longer required, removing 16.6 MTPA from the market and resulting in only 6.2 MTPA of net regasification capacity growth. Their departures highlight the inherent flexibility provided by offshore terminals as FSRUs can be added and removed with relative ease, particularly in markets subject to significant demand swings. Nonetheless, multiple new regasification terminals and expansion projects were set to begin operations in early 2019, including in Thailand, India, Chinese Taipei, China, Jamaica, Russia (Kaliningrad), Bahrain, and Bangladesh. Indeed, Russia (Kaliningrad) and Bahrain were expected to begin operations at their first regasification terminals in early 2019 after an FSRU arrived in Kaliningrad in December 2018 and a floating storage unit arrived in Bahrain in January 2019.

The majority of near-term regasification capacity growth is still expected to occur in established importing markets, particularly in Asia through additions in China, India, and elsewhere in the region. Although their regasification capacities are not yet on the scale of many existing importing markets, many new LNG importers continue to add or plan to develop regasification terminals, which could ultimately add a significant aggregate capacity volume in the future. Following the addition of Bangladesh and Panama in 2018 and of Russia (Kaliningrad) in early 2019, new markets including Bahrain, Croatia, El Salvador, Ghana, and the Philippines are in the process of constructing their first regasification terminals and will begin LNG imports in the next few years. Further, many other markets have proposed adding regasification capacity, including Australia, Sudan, Cyprus, Ireland, Nigeria, Côte D'Ivoire, Lebanon, Namibia, Vietnam, China (Hong Kong), South Africa, Morocco, and Germany. However, many of the markets listed have been subject to numerous delays in bringing terminals to fruition as a number of these developments face substantial headwinds to move forward, particularly in financing and infrastructure development. Despite these challenges, the trend of adding new importers to the global LNG market is expected to continue with a few new markets expected to emerge per year in the near-term.

Incheon Terminal - Courtesy of KOGAS

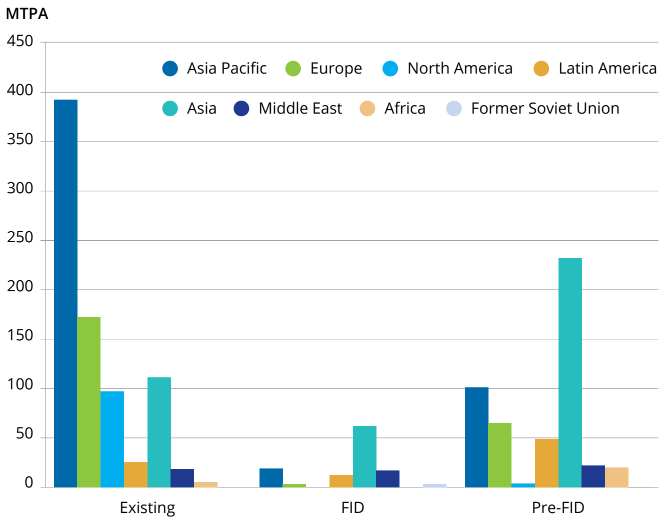
[1] All counts and totals within this section only include markets with large-scale LNG regasification capacity (0.5 MTPA and above). This includes markets that only regasify domestically-produced LNG, which may cause totals to differ from those reported in Chapter 3: LNG Trade. Refer to Chapter 10: References for a description of the categorization of small-scale versus large-scale LNG.

[2] Some individual capacity numbers have been restated over the past year owing to improved data availability and a methodological change in accounting for mothballed and available floating capacity. This may cause global capacity totals to differ compared to the IGU World LNG Report – 2018 Edition.

6.1 OVERVIEW

Two new markets, Bangladesh and Panama, added LNG regasification capacity in 2018. Beyond those two, new terminals were constructed in China, Japan, and Turkey, all of which were existing LNG markets. China and Greece also completed regasification capacity expansion projects at existing plants. Furthermore, one expansion project in Thailand came online in January 2019. In sum, these additions brought total LNG regasification capacity in the global market to 824 MTPA across 36 markets[3] as of February 2019 (see Figure 6.1).

Figure 6.1: LNG Receiving Capacity by Status and Region, as of February 2019



Sources: IHS Markit, Company Announcements

824 MTPA[4]
Global LNG nameplate receiving capacity, February 2019

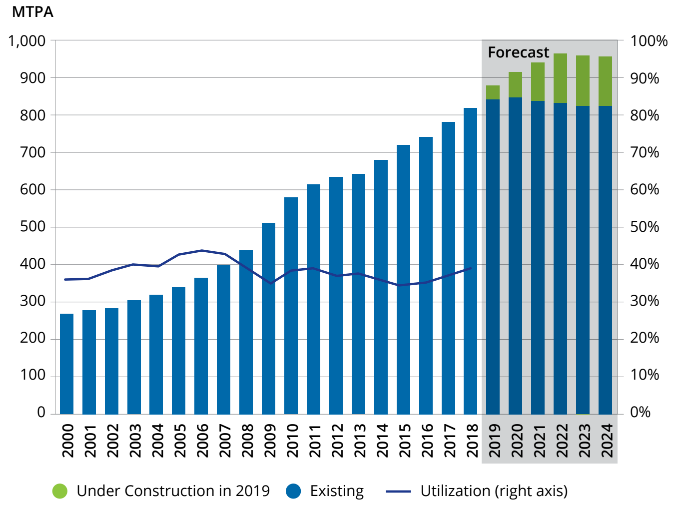
The global market's largest levels of regasification capacity are located in the Asia and Asia Pacific regions.[5] The two regions are anticipated to continue their high rates of capacity expansion moving forward in both growth markets as well as established LNG importers. Despite having high levels of existing regasification capacity, North America has not experienced capacity growth in recent years outside of small-scale projects in the Caribbean region due to increases in domestic production. The introduction of FSRUs have allowed several new markets to access the global LNG market over the last decade, especially in the Middle East, Asia, and Latin America. Indeed, Bangladesh's first regasification terminal is an FSRU added in 2018. FSRUs could continue to play an important role in bringing LNG imports to new markets quickly, provided there is sufficient pipeline and offloading infrastructure in place. However, while construction timelines are typically longer at onshore regasification terminals, they offer the stability of a permanent, larger-scale solution and thus will continue to be important to accommodate the needs of growing LNG importers.

6.2 RECEIVING TERMINAL CAPACITY AND REGASIFICATION UTILISATION GLOBALLY

In 2018, 22.8 MTPA of new regasification capacity was constructed. This is a slower rate of growth than experienced in 2017, when 45 MTPA of new capacity was completed. The new markets of Bangladesh and Panama added to regasification growth in 2018, following 2017 when capacity was only constructed at existing markets, which had marked the first time in ten years without a new regasification market[6]. The number of importers with regasification infrastructure has expanded significantly in recent years, more than tripling over the past 15 years. Increasingly flexible supply has supported LNG trade growth, and FSRUs have played a larger role in allowing new markets to access LNG supply at a faster rate as observed in Egypt and Pakistan in 2015 or in Bangladesh in 2018. LNG trade growth has also benefited from previous periods of lower global LNG prices, driving demand in markets 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, new markets continue to join the ranks of LNG importers even in established importing regions like Europe.

[3] The total number of markets excludes those with only small-scale (<0.5 MTPA) regasification capacity, such as Finland, Jamaica, Malta, Norway, and Sweden. It includes markets with large-scale regasification capacity that only consume domestically-produced cargoes, such as Indonesia.
[4] Total excludes regasification capacities from Abu Dhabi (Ruwais), Ain Sokhna Höegh, Bahia Blanca, and Guanabara Bay as FSRU charters ended at those ports in 2018.
[5] Please refer to Chapter 10: References for an exact definition of each region.
[6] Although Malta began LNG imports in 2017, its terminal is small-scale (0.4 MTPA) and thus not included in this chapter.

Figure 6.2: Global Receiving Terminal Capacity, 2000-2024

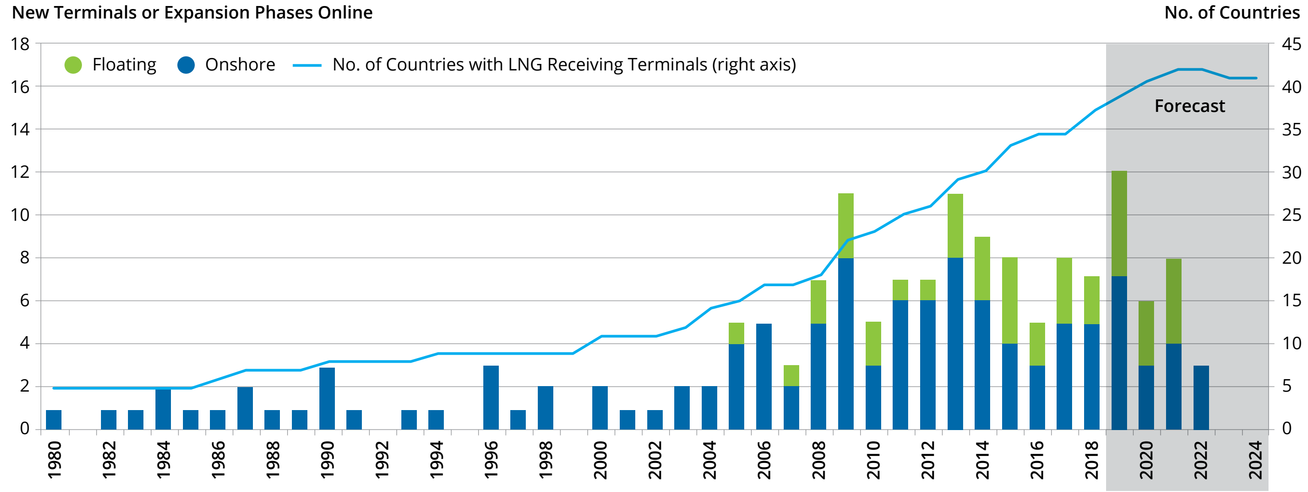


Note: The above forecast only includes projects sanctioned as of February 2019. Regasification utilisation figures are calculated using regasification capacity prorated based on terminal start dates. Owing to short construction timelines for regasification terminals, additional projects that have not yet been sanctioned may still come online in the forecast period. Capacity declines over the forecast period as FSRU charters conclude, although new charters may be signed during this time.
Sources: IHS Markit, IGU, Company Announcements

Seven new regasification terminals achieved commercial operations in 2018 (see Figure 6.3). Five of these new terminals were completed in the Asia or Asia Pacific regions, including three in China (Shenzhen, Tianjin (Sinopec), and Zhoushan), Japan (Soma), and Bangladesh (Moheshkhali (Petrobangla)). Panama added its first terminal (Costa Norte) in 2018, the first new regasification terminal for the Latin America region since Colombia's Cartagena terminal in 2016. In Europe, Turkey's Dortyol terminal began commercial operations in early 2018 after completing construction in 2017. In total, 20.7 MTPA of regasification capacity was added in new terminals in 2018.

7 terminals
Number of new receiving terminals brought online in 2018

Figure 6.3: Start-Ups of LNG Receiving Terminals, 1980-2024.



Note: Forecast only includes under-construction terminals as of February 2019. Owing to short construction timelines for regasification terminals, additional projects that have not yet been sanctioned may still come online in the forecast period. The decrease in number of markets with receiving terminals is due to the expiration of FSRU charters, although new FSRU charters may be signed during this time period.
Sources: IHS Markit, Company Announcements

Furthermore, there were an additional two expansion projects completed at existing regasification terminals in 2018. China's Qidong terminal added 0.6 MTPA of capacity, expanding the terminal's total regasification capacity to 1.2 MTPA. Greece's Revithoussa terminal also added 1.5 MTPA of capacity in the second capacity expansion at the terminal, increasing total capacity to 4.8 MTPA. The 2.1 MTPA of expansion projects, in combination with the 20.7 MTPA of new terminals, brought total added regasification capacity in 2018 to 22.8 MTPA.

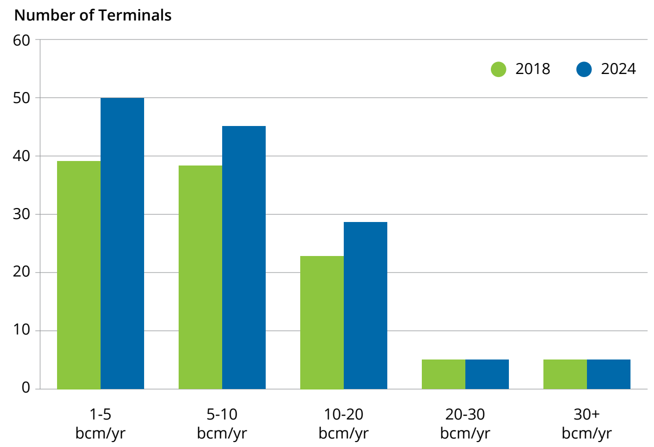
Four terminals had FSRUs leave their ports during 2018 as the vessels were no longer needed. Lower LNG demand in the UAE led to the *Excelerate* being re-chartered as a carrier vessel in mid-2018. The *Hoegh Gallant's* charter was ended early in October 2018 as Egypt's domestic gas production has increased significantly. In Argentina, the *Exemplar* FSRU left the Bahia Blanca terminal in October 2018 after it was decided that the charter would not be renewed. Brazil's Guanabara Bay terminal ended the charter of the *Golar Spirit* FSRU early in 2017, but temporarily brought in an FSRU in third quarter 2018 during a maintenance period at an offshore domestic gas processing platform. In sum, 16.6 MTPA of active regasification capacity was removed from the market as the FSRUs left without any clear announcement of future charters for the terminals.

One expansion project, adding 1.5 MTPA at Thailand's Map Ta Phut terminal, came online in January 2019. Beyond this project, 129.7 MTPA of new regasification capacity was under construction as of February 2019, including seventeen new onshore terminals, twelve FSRUs, and thirteen expansion projects to existing receiving terminals. Although 87% of this total capacity will be in existing import markets, six under-construction projects are anticipated to add capacity for the first LNG imports in Russia (Kaliningrad), Bahrain, the Philippines, El Salvador, Ghana, and Croatia. Indeed, the *Marshal Vasilevskiy* FSRU arrived in Kaliningrad in late December 2018 and the Bahrain Spirit floating storage unit arrived in Bahrain in January 2019, where operations were expected to begin imminently. China has nine terminals under construction, along with eight expansion projects, while India has five new terminal projects and an expansion project under construction. Brazil has two forthcoming FSRU projects also in development. Additional terminal construction and regasification capacity expansion projects are underway in Jamaica, Bangladesh, Belgium, South Korea, Japan, Kuwait, Poland, Indonesia, United States (Puerto Rico), and Thailand. An FSRU, the *Golar Freeze*, arrived at Old Harbour in Jamaica in December 2018, with operations expected to begin in early 2019.

129.7 MTPA
New receiving capacity under construction, as of February 2019

Average regasification utilisation levels across the global LNG market reached 39% in 2018. If idled or mothballed[7] terminals were included, this figure would drop to 36% globally. Onshore regasification terminals operated at 39% of capacity in 2018, roughly equal to 38% of capacity at offshore terminals 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 6.2 MTPA of net regasification capacity was added in 2018 (22.8 MTPA of new additions minus 16.6 MTPA from FSRU departures over the course of the year), the average levels of global regasification utilisation increased slightly on higher demand globally. US imports utilised just 4% of the market's 75 MTPA existing active regasification capacity[8], as domestic gas production from shale has expanded.

Figure 6.4: Annual Regasification Capacity of LNG Terminals in 2018 and 2024.



Sources: IHS Markit, Company Announcements

Due to multiple small-to medium-sized terminals in smaller markets beginning operations, average send-out capacity at regasification terminals has trended downwards over the last few years. Further intensifying this trend is the proliferation of floating regasification terminals installed worldwide, whose capacity is generally below 6 MTPA. Average regasification capacity for existing onshore terminals stood at 7.2 MTPA as of February 2019 compared to 4.0 MTPA for floating terminals. Global average regasification capacity has fallen from 9.8 billion cubic meters per year (bcm/yr; equivalent to 7.1 MTPA) in 2011 to 8.7 bcm/yr (6.4 MTPA) in 2018 (see Figure 6.4).

7 Includes Lake Charles, Cameron LNG, Golden Pass, Gulf LNG, and El Musel regasification terminals.
8 Including Puerto Rico's Peñuelas regasification terminal.

6.3 RECEIVING TERMINAL CAPACITY AND REGASIFICATION UTILISATION BY MARKET

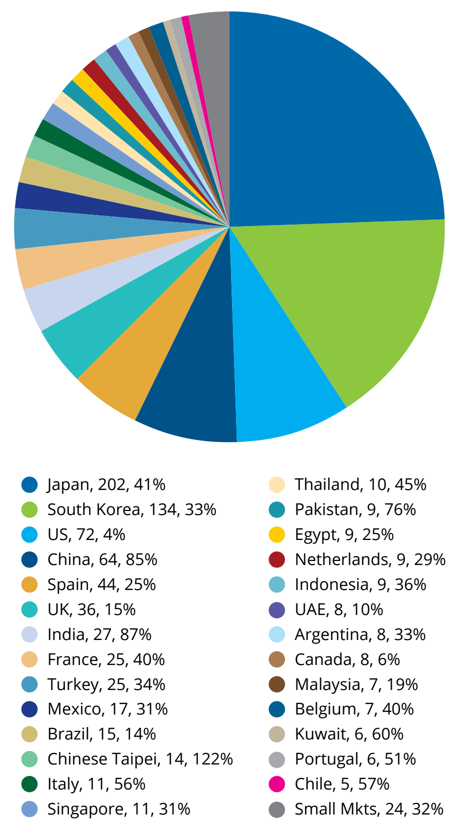
The market with the largest regasification capacity is also the largest LNG importer, Japan (see Figure 6.5). Japan's regasification capacity stood at 202 MTPA[9] in 2018, which includes the new 1.3 MTPA Soma terminal completed in early 2018. Japan's total accounts for 24% of global regasification capacity. Despite already being the global leader in regasification capacity, Japan continues to expand its importing abilities with a 3.8 MTPA expansion project at the Hitachi terminal under construction as of February 2019. At year end, Japan's regasification utilisation reached 41%, down slightly from 2017.

At 134 MTPA[10] of regasification capacity in 2018, South Korea has the second largest regasification capacity in the world, behind only Japan. The market remained the third largest LNG importer in 2018, following Japan and China. Although South Korea did not add any regasification capacity in 2018, one new terminal was under construction as of early 2019, the 1 MTPA Jeju Island project. South Korea experienced a regasification utilisation rate of 33% in 2018, up from 30% in 2017 as LNG demand increased owing to lower utilisation of nuclear and coal-fired power.

China became the second largest LNG import market in 2017, surpassing South Korea, and held this position throughout 2018; however, China is still behind South Korea in total regasification capacity, though the gap between them is quickly closing. China continues to be one of the fast-growing regasification markets, adding 10.6 MTPA of capacity in 2018. In addition, the market has 37.6 MTPA of capacity under construction as of February 2019. In terms of total regasification capacity, China is the fourth largest market in the world at 64 MTPA nameplate capacity in 2018. Notably, this is up from only 10 MTPA in 2008. China's regasification utilisation continued to rise significantly in 2018, reaching 85%, up from 70% in 2017 and 56% in 2016. Given northern China's colder climate in the winter, utilisation is typically high between November and March in comparison to southern China. Utilisation has consistently increased due to significantly higher imports as the market sought to reduce air pollution through coal-to-gas switching.

India has 26.5 MTPA of regasification capacity under construction as of February 2019 as the market is anticipated to be a significant source of growth for the LNG market moving forward. India's 27 MTPA of existing capacity in 2018 is the seventh largest in the world. India is expected to complete 14 MTPA of additional capacity in early 2019 at the Ennore, Jaigarh, and Mundra terminals, which will increase total capacity to 41 MTPA. Furthermore, based on announced proposed projects, India's total regasification capacity could reach as high as 98 MTPA by 2021. Eastern India requires additional supply since domestic upstream projects have either under-performed or been delayed. Moreover, new gas-consuming sectors such 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 market. 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. India's regasification utilisation rate hit 87% in 2018, a rise from 72% in 2017.

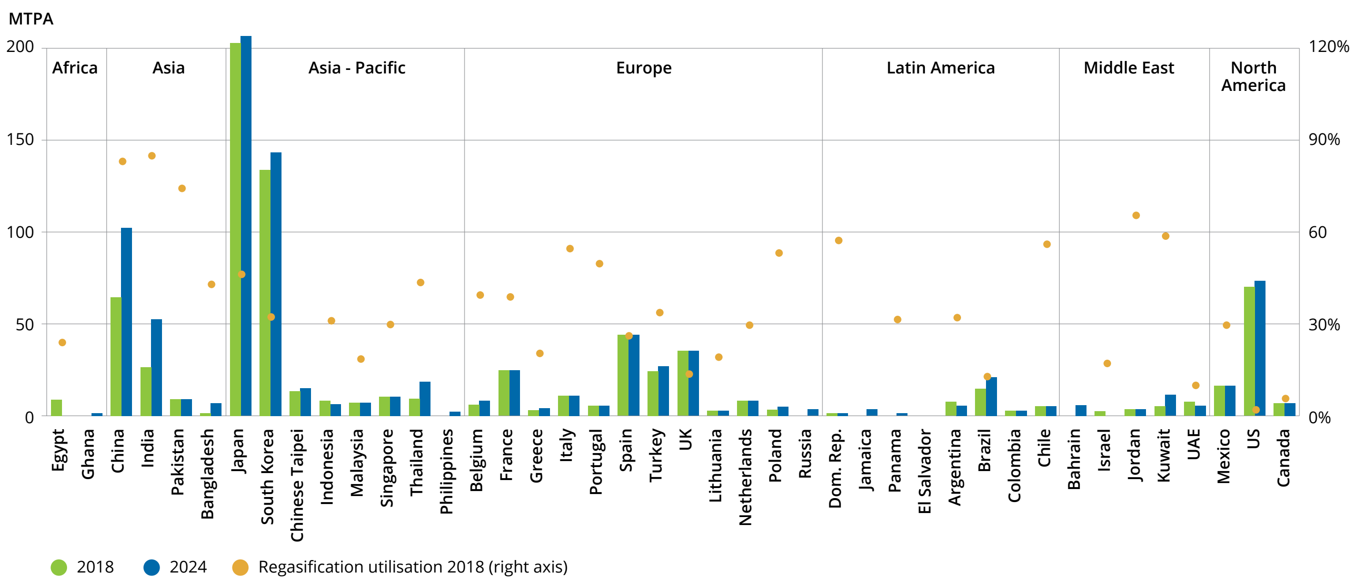
Figure 6.5: LNG Regasification Capacity by Market (MTPA) and Annual Regasification Utilisation, 2018.



Note: "Smaller Markets" includes (in order of size): Jordan, Poland, Greece, Lithuania, Israel, Colombia, Dominican Republic, Bangladesh, and Panama. Each of these markets had 4 MTPA or less of prorated capacity as of end-2018. Regasification utilisation figures are based on 2018 trade data and prorated regasification capacity based on terminal start dates in 2018. Prorated capacity in 2018 is displayed in this graph.
Sources: IHS Markit, IGU

9 Historical Japan regasification capacity figures have been restated this year owing to greater data availability.
10 Historical South Korea regasification capacity figures have been restated this year owing to greater data availability.

Figure 6.6: Receiving Terminal Import Capacity and Regasification Utilisation Rate by Market in 2018 and 2024.



Note: Forecast only includes under-construction capacity as of February 2019. Regasification utilisation figures are calculated using 2018 import data and prorated regasification capacity based on terminal start dates in 2018 and 2024. Prorated capacity in each year is displayed in this graph. Capacity declines over the forecast period are due to FSRU charter expirations, although new charters may be signed during this period.
Sources: IHS Markit, IGU, Company Announcements

Europe accounts for roughly 20% of total global regasification capacity, but regasification utilisation rates have generally been low, owing to competition from pipeline gas coupled with weaker gas demand in the power sector. Utilisation averaged 33% in 2018 (up from 30% in 2017). This figure, however, varies widely by market, ranging from 15% in the United Kingdom to 56% in Italy (see Figure 6.6). As global LNG supply increased throughout 2018, lower LNG spot prices and standard weather conditions in Asia pushed more cargoes normally destined for the region into Europe, causing utilisation rates to rise toward the end of the year.

Turkey was the only European market to develop a new regasification terminal in 2018 (the Dortyol FSRU), after also adding a terminal in 2017. 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 and an expansion project was underway at the terminal as of February 2019; the market is also planning to add an FSRU at Gdansk. Another expansion project is under construction at Zeebrugge in Belgium, which will add 2.2 MTPA. Another FSRU project in Turkey, the Saros project, is targeted to start up in 2019. Russia's FSRU in the Kaliningrad exclave arrived in late December 2018, poised to be the market's first regasification terminal as operations begin in 2019. Further down the road, Croatia is set to become an LNG importer after taking FID on its Krk LNG terminal in February 2019. Elsewhere on the Mediterranean Sea, Greece and Bulgaria are pushing to install an FSRU at Alexandroupolis. Spain has proposed gasifying the Canary Islands via LNG. In northwest Europe, both Germany and Ireland have proposed adding their first regasification terminals. These plans include the Wilhelmshaven and Brünnsbüttel terminals in Germany and the Innisfree and Shannon terminals in Ireland. Although small-scale, Gibraltar (UK) is expected to complete its first LNG terminal in 2019.

Behind only Japan and South Korea, the US contains the third highest level of regasification capacity in the world. However, its terminals remain minimally utilised, if at all; the market averaged 4% regasification utilisation in 2018, largely supported by imports at the Peñuelas regasification terminal in Puerto Rico. In recent years Puerto Rico has experienced regasification utilisation figures over

LNG for Transport - Courtesy of Shell

100% – reaching 113% in 2018 – except for a low year (80%) in 2017 when the market was affected by Hurricane Maria. Puerto Rico is currently constructing its second terminal, an FSRU, set to come online in 2019. Six different terminals in the US received cargoes in 2018, although several of these were likely only cooling cargoes in preparation for the addition of liquefaction capacity; most US regasification terminals that intend to add liquefaction operations have been planned as bidirectional facilities. The Cameron LNG, Golden Pass, Gulf LNG, and Lake Charles regasification terminals are all considered idled and not included in active capacity totals as they haven't imported cargoes for several years and are assumed to have warm storage tanks. However, regasification capacity at Cameron LNG is expected to start back up in early 2019 as preparations for liquefaction activities ramp up. If all currently idled terminals were included, the US would have a total 131 MTPA of regasification capacity. The prospect of ample, price-competitive domestic gas production means that LNG imports are not expected to increase, and many terminal operators have focused on adding export liquefaction capacity to take advantage of the shale gas boom. As regasification capabilities still exist at these terminals, their capacity will become viable again as storage tanks cool down once liquefaction operations begin.

Canada also had one of the lowest regasification utilisation levels in 2018 (6%), also due to the availability of domestic production. Chinese Taipei (122%) registered the highest regasification utilisation in 2018 as the market has typically received higher volumes than its announced regasification capacity, often leading to utilisation levels over 100%.

Although Kuwait is currently a relatively small LNG import market, with only 6 MTPA of existing regasification capacity, it is notably constructing one of the largest regasification terminals in recent years. The Al Zour terminal will have an initial regasification capacity of 11.3 MTPA, with a potential expansion up to 22.3 MTPA; the first phase is announced to come online in 2021. The last regasification terminal larger than 10 MTPA to be completed was South Korea's Samcheok terminal (11.6 MTPA) in 2014.

As LNG exports have increased significantly in eastern Australia since 2015, the market has experienced spikes in regional domestic gas prices. In response, multiple FSRU developments have been proposed in an effort to provide alternative gas sources, meaning Australia could soon join the small group of markets that both export and consume LNG cargoes. The Crib Point terminal in Victoria signed a charter agreement with an FSRU supplier in December 2018 and targets a start date of 2021-2022, though some of the projects have targeted start dates as early as 2020.

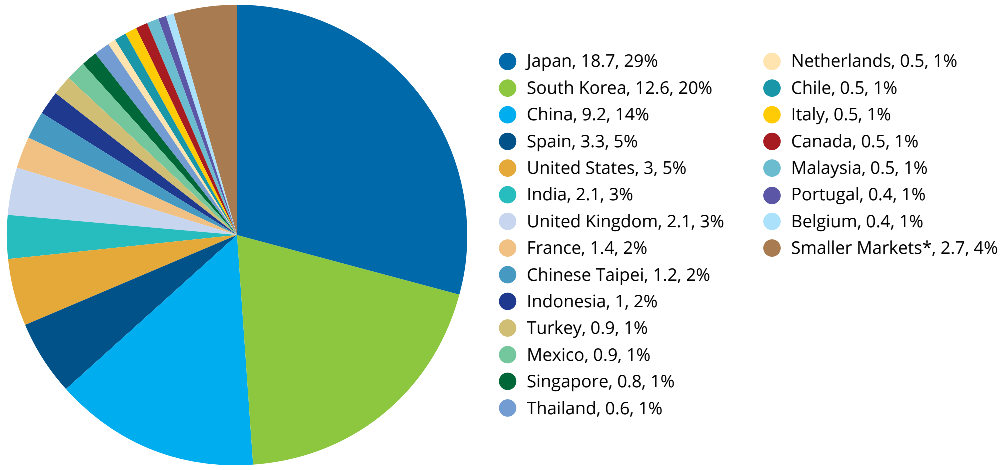
2017-2018 LNG Receiving Terminals in Review

Receiving Capacity	New LNG onshore import terminals	New LNG Offshore terminals	Number of regasification markets
+6.2 MTPA Net growth of global LNG receiving capacity	**+5** Number of new onshore regasification terminals	**+2** Number of new offshore LNG terminals	**+2** Markets that added regasification capacity
Net nameplate regasification capacity grew by 6.2 MTPA, from 816.4 MTPA in end-2017 to 822.6 MTPA in end-2018 New regasification additions reached 22.8 MTPA in 2018, but were offset by the departures of FSRUs in Argentina, Brazil, Egypt, and UAE amounting to 16.6 MTPA Growth in capacity was led by the Asia and Asia Pacific regions in 2018	New onshore terminals were added in in China, Japan, and Panama Two expansion projects at existing onshore terminals, in China and Greece, were also completed in 2018 One expansion project was completed in Thailand in January 2019	Two FSRUs began commercial operations in 2018, in Turkey (Dortyol), and Bangladesh (Moheshkhali (Petrobangla)) FSRUs also arrived at Old Harbour in Jamaica and Kaliningrad in Russia in December 2018, with operations expected to commence in early 2019	The number of markets with regasification capacity increased to 36 in 2018, following the addition of Panama and Bangladesh. Russia (Kaliningrad), the Philippines, Ghana, and Bahrain all have their first regasification projects in advanced development stages in 2019, set to come online over the next few years

6.4 RECEIVING TERMINAL LNG STORAGE CAPACITY

The strategic importance of natural gas storage capabilities is expanding as LNG supply ramps up worldwide, particularly in Asia and Europe. Global LNG storage capacity grew to 64 million cubic meters (mmcm) through end-2018 following the addition of seven new regasification terminals and two expansion projects over the year. The average storage capacity for existing terminals in the global market was 528 thousand cubic meters (mcm) as of early 2019 (see Figure 6.7).

Figure 6.7: LNG Storage Tank Capacity by Market (mmcm) and % of Total, as of February 2019



Note: "Smaller Markets" includes (in order of size): Poland, Brazil, Greece, Panama, Egypt, Kuwait, Lithuania, Colombia, Pakistan, Jordan, Dominican Republic, United Arab Emirates, Israel, Bangladesh, and Argentina. Each of these markets had less than 0.4 mmcm of capacity as of February 2019.
Sources: IHS Markit, Company Announcements

Over 45% of the LNG market's total existing storage capacity is contained in the twenty LNG terminals with the largest storage capabilities, which range from 0.7 to 3.4 mmcm in size. Out of these twenty terminals, fifteen are in the Asia and Asia Pacific regions, as terminal operators in the region have 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.

South Korea's Pyeongtaek terminal has the largest storage capacity in the world at 3.36 mmcm. Capacity in South Korea has continued 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. China added a total of 1.8 mmcm of storage capacity in 2018 through the addition of three new regasification terminals and an expansion project, increasing the market's total storage capacity to 9.2 mmcm, the third largest in the global market behind only Japan and South Korea. The Tianjin (Sinopec) and Shenzhen terminals each added 0.64 mmcm of capacity. Outside of Asia, small storage capacity increases were added in 2018 in Turkey (0.26 mmcm), Panama (0.18 mmcm), and Greece (0.1 mmcm) through new terminals and expansion projects.

Trends in global storage capacity developments are diverging. On the one hand, there is storage capacity growth in established LNG markets, particularly via onshore terminals in Asia, compared to a downward shift in average storage capacity in newer markets that utilise FSRUs to import LNG. In general, FSRUs contain substantially less storage capacity than onshore terminals. Onshore terminals generally contain between 260 and 700 mcm of storage capacity, whereas floating terminals typically utilise storage tanks between 125 and 170 mcm in size.

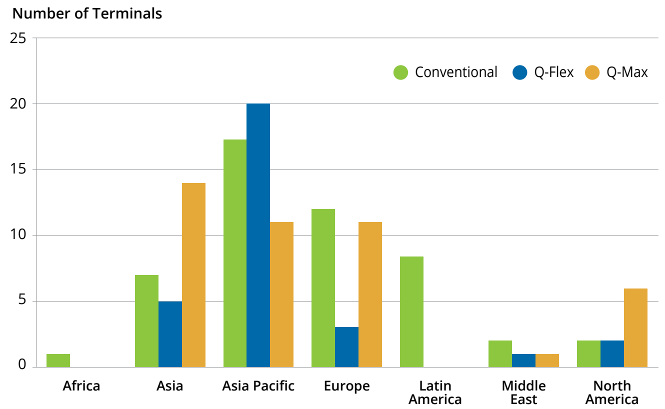
Furthermore, storage capacity can potentially provide value beyond storing LNG that is later regasified. Storage capacity can also be utilised for transhipment and truck-loading capabilities. Although these processes generally require small volumes of LNG, they are expected to comprise a growing portion of LNG demand growth moving forward.

6.5 RECEIVING TERMINAL BERTHING CAPACITY

Regasification terminals vary significantly in terms of the capacity of carrier vessels they can accommodate. A multitude of factors, including a terminal's size and location, can influence its berthing capacity. Following a similar trend as the divergence in global storage capacities, 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. Typically, 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.

Q-Max vessels are the LNG market's biggest carrier vessel size, with capacities of around 266,000 cm. As of early 2019, 43 out of 126 existing regasification terminals, located in 17 different markets, were known to have the berthing capacity to receive a Q-Max vessel (see Figure 6.8). Of these 44 terminals, 25 were in the Asia or Asia Pacific regions, while the Middle East only has one such terminal, and Latin America and Africa have none. Q-Flex vessels have a capacity around 217,000 cm; a further 31 regasification terminals had berthing capacities to receive Q-Flex carriers, as well as conventional LNG vessels. Out of 36 total import markets, 24 were confirmed to have a minimum of one terminal with receiving capacity for Q-Class vessels. Of the 52 terminals that are estimated to be limited to receive conventional vessels, 16 are FSRUs. Many terminals are also adjusting to accommodate small-scale and bunkering vessels to comply with emissions targets and capture new commercial opportunities. Several terminals with multiple jetties such as GATE and Barcelona can receive a wide variety of vessels sizes, ranging from Q-Max vessels all the way down to small-scale ships, some as low as 500 cm.

Figure 6.8: Maximum Berthing Capacity of LNG Receiving Terminals by Region, 2018[11].



Sources: IHS Markit, Company Announcements

Queensland Curtis LNG Plant - Courtesy of Shell

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

6.6 RECEIVING TERMINALS WITH RELOADING AND TRANSSHIPMENT CAPABILITIES

Some LNG importing markets have the capability re-export imported LNG cargoes to destinations elsewhere in the global LNG market, a phenomenon that has occurred more frequently in recent years. These are generally markets with access to alternative pipeline supply that take advantage of arbitrage opportunities through LNG trade between basins as well as specific logistical factors within certain markets. France re-exported the most cargoes in 2018 for the third consecutive year, at 1.4 MTPA, utilising the Montoir, Fos Cavaou, and Dunkirk terminals. After France, the Netherlands re-exported the second largest volume of cargoes in 2018. Prior to 2016, Spain and Belgium historically sent out the most re-exported volumes, although cargoes from both markets have dwindled in recent years. Even as the markets within the region vary, Europe continues to produce the highest volume of re-exports as it has since re-exports began in the 2000s. There are 15 terminals in Europe (out of 26 existing terminals) that are capable of re-exports. Lithuania began re-exports within the region in 2017, although these volumes are small-scale in nature. However, the share of non-European re-exports in the global LNG market has risen in recent years, reaching 27% of total re-exports in 2018. Although this was down from 40% in 2017, re-exports from the Asia and Asia Pacific regions have expanded steadily since 2016. Indeed, Singapore produced the third most reloaded cargoes and was essentially on par with the Netherlands, reaching 0.7 MTPA in 2018 – the most for a non-European market since the United States re-exported 1.1 MTPA in 2011.

Although there were no new markets that re-exported LNG cargoes in 2018, France's Dunkirk regasification terminal generated its first re-export cargoes in early 2018. Japan and the Dominican Republic both produced their first re-exports in 2017 via the Sodeshi and Andres terminals, respectively. The Andres terminal also added the capability to re-export small-scale volumes to terminals in the Caribbean region. As of February 2019, 28 terminals in 15 different markets 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.

Table 6.1: Regasification Terminals with Reloading Capabilities as of February 2019.

Market	Terminal	Reloading Capability	Storage (mcm)	No. of Jetties	Start of Re-Exports
Belgium	Zeebrugge	4-5 mcm/h	380	1	2008
Brazil	Guanabara Bay	1.0 mcm/h	171	2	2011
Brazil	Bahia	5.0 mcm/h	136	1	N/A
Brazil	Pecém	1.0 mcm/h	127	2	N/A
Colombia	Cartagena	0.005 mcm/h	170	1	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	2018
France	Fos Tonkin	1.0 mcm/h	150	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	3	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	1	2011
Spain	Mugardos	2.0 mcm/h	300	1	2011
Spain	Barcelona	3.5 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	2.5 mcm/h*	800	2	2010
USA	Cameron	2.5 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 re-loadings within Spain. ***Reloading capacity permitted by the US DOE.*
Sources: IHS Markit, IGU

Terminals with multiple jetties have the ability to complete trans-shipments 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 500 cm.

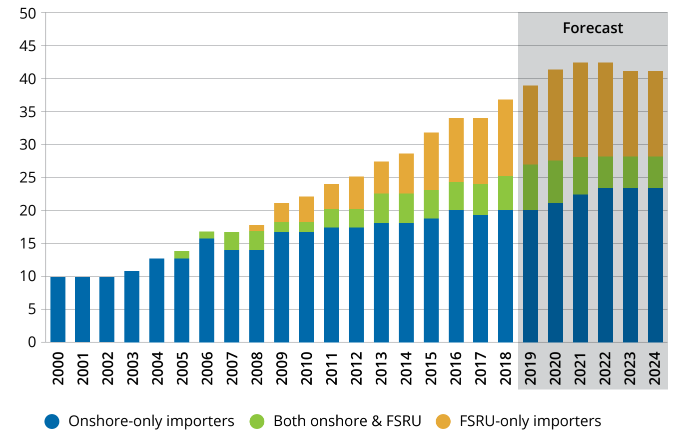
Though volumes currently remain small, the transportation and industrial sector is expected to provide growth in the LNG market over the long term. Multiple receiving facilities have developed bunkering and truck loading capabilities. France's Fos Cavaou terminal is set to add LNG bunkering services beginning in 2019. Poland has also announced plans to add a second jetty at the Swinoujscie terminal to allow for bunkering and trans-shipments. In addition, small-scale consumption has increased, reaching isolated demand pockets outside of the primary pipeline infrastructure. Spain has demonstrated the use of intermodal LNG International Organisation for Standardisation (ISO) container transport through truck, train, and ship.

Submarine Pipeline - Courtesy of KOGAS

6.7 COMPARISON OF FLOATING AND ONSHORE REGASIFICATION

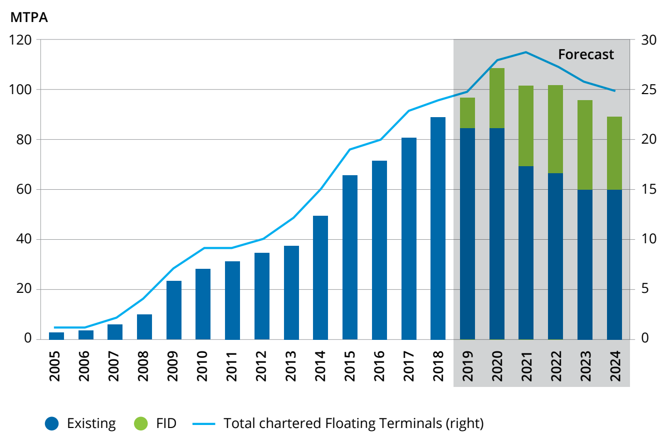
As of February 2019, nearly 85% of existing terminals were located onshore. Although the ratio of onshore to offshore terminals has been shifting toward the latter in recent years, five of the seven terminals that began operations in 2018 were onshore developments. This was largely caused by onshore additions to established markets in Asia, including China and Japan. However, only seventeen of the twenty-nine terminals under construction as of early 2019 are listed as onshore proposals. The addition of FSRUs has provided a pathway for a number of new markets to join the global LNG market throughout the last few years, including Bangladesh in 2018 (see Figure 6.9). Out of the thirty-six existing LNG import markets in February 2019, sixteen had FSRU capacity, and five of those had onshore capacity as well. Five FSRU projects were under construction and have announced plans to come online by end-2019, totalling 15.4 MTPA. These include the new markets of Russia (Kaliningrad) and Jamaica (which currently imports LNG via small-scale regasification capacity), as well as Bangladesh, the United States (Puerto Rico), and India. Furthermore, multiple under-construction projects for FSRUs are being planned for start-up in 2020-2021, particularly in Ghana, El Salvador, and Croatia, all of which would be new import markets. Beyond those three, Australia, Côte D'Ivoire, Cyprus, China (Hong Kong), Ireland, Lebanon, Myanmar, Namibia, Nigeria, South Africa, and Sudan have all proposed FSRU projects in order to join the global LNG market. Nevertheless, there are still several new importers that have announced plans to enter the LNG market using onshore proposals to establish a more permanent solution for gas imports such as Bahrain, Morocco, the Philippines, and Vietnam. Notably, Germany has proposed both onshore and FSRU regasification concepts in its efforts to join the global LNG market.

Figure 6.9: Rise of FSRUs among Import Markets, 2000-2024



Note: The above graph only includes importing markets that had existing or under-construction LNG import capacity as of end-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. The decrease in number of markets with receiving terminals is due to the expiration of FSRU charters, although new FSRU charters may be signed during this period.
Sources: IHS Markit, Company Announcements

Figure 6.10: Floating Regasification Capacity by Status and Number of Terminals, 2005-2024



Note: The above forecast only includes floating capacity sanctioned as of end-2018. Owing to short construction timelines for FSRUs, additional projects that have not yet been sanctioned may still come online in the forecast period. The decrease in floating capacity is due to the expiration of FSRU charters, although new FSRU charters may be signed during this period.
Sources: IHS Markit, Company Announcements

Two new floating terminals began operations in 2018: Turkey's 4.1 MTPA Dortyol terminal and Bangladesh's 3.8 MTPA Moheshkali (Petrobangla) terminal, the latter market's first regasification terminal. However, four terminals had their FSRUs leave port in 2018 as their services were no longer required, highlighting the inherent flexibility of deploying FSRUs. After their charters ended, Bahia Blanca in Argentina, Guanabara Bay in Brazil, Ain Sokhna Hoegh in Egypt, and Abu Dhabi in the United Arab Emirates all had FSRUs leave port with no clear intentions of chartering a replacement vessel in the near term. Combined, the departure of the FSRUs at the four terminals reduce active floating regasification capacity by 16.6 MTPA. Furthermore, while the *Golar Igloo* left Kuwait's Mina al-Ahmadi terminal at the end of 2018 as the charter expired, it is expected that a replacement vessel will be chartered in the near term as Kuwait requested a charter extension into 2020. As of January 2019, total active floating import capacity stood at 80.1 MTPA at 20 terminals (see Figure 6.10). However, two new FSRU projects had FSRUs in place starting in December 2018 with operations expected to begin in early 2019: Kaliningrad in Russia and Old Harbour in Jamaica.

Onshore terminals and FSRUs each provide distinct benefits and drawbacks for regasification terminal utilisation. These factors are very reliant on specific target market requirements and conditions, and will vary on a case-by-case basis. In recent years, several first-time importing markets have all joined the global LNG market through the addition of floating regasification, including Bangladesh, Egypt, Jordan, Pakistan, Abu Dhabi, and Colombia. FSRUs can be brought online faster than onshore terminals, allowing for faster fuel switching. This can be important for new markets that 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. 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. FSRUs also provide flexibility to terminal operators to release the vessel if regasification capacity is no longer required, as observed in Argentina, Brazil, Egypt, and the United Arab Emirates in 2018.

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 capital expenditures (CAPEX)
Requires lower operating expenditures (OPEX)	Depending on location, fewer regulations
Option for future expansions	

On the other hand, onshore terminals also deliver a number of benefits over floating regasification terminals, depending on the market's specific requirements. 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. Floating regasification can also face several potential location-based risks that are avoided by onshore projects, such as a longer LNG deliverability downtime, vessel performance, and heavy seas or meteorological conditions. Bangladesh's FSRU faced a number of these challenges in reaching full operations in 2018, as start-up was delayed several months due to technical and infrastructure challenges, as well as rough seas during monsoon season. FSRUs also may experience limitations or challenges with onloading capacities that many onshore terminals can circumvent. In addition, depending on the location, onshore projects can permit future on-site regasification and storage expansion plans.

After a surge in FSRUS over the past two decades, the demand for new floating capacity may be nearing a balancing point. While multiple new markets continue to add or plan to develop FSRUs in order to join the global LNG market, other markets have allowed FSRU charters to expire as capacity was no longer required. Furthermore, several markets have even completely abandoned FSRU proposals in favour of onshore developments as their demand increases. For more information on FSRU activity and uses, please refer to Chapter 9: Floating LNG.

Twelve FSRUs (with capacities over 60,000 cubic meters) were announced to be on the order book, including conversion orders, as of February 2019. In addition, multiple FSRUs were open for charter around the same time, indicating sufficient near-term floating regasification capacity. Furthermore, as some floating terminal projects have been delayed or cancelled, the number of FSRUs being used as conventional carriers has increased. With multiple FSRUs ordered on a speculative basis, there is ample near-term FSRU capacity, leading some FSRU developers to slow down their buildout aspirations. Nonetheless, the value of bringing a new import market online quickly is set to grow over time as the global LNG market expands. The number of proposed floating projects is steadily rising and reaching historic highs, underlining the perceived importance of FSRUs in supporting new LNG markets.

LNG Schneeweisschen - Courtesy of DSME

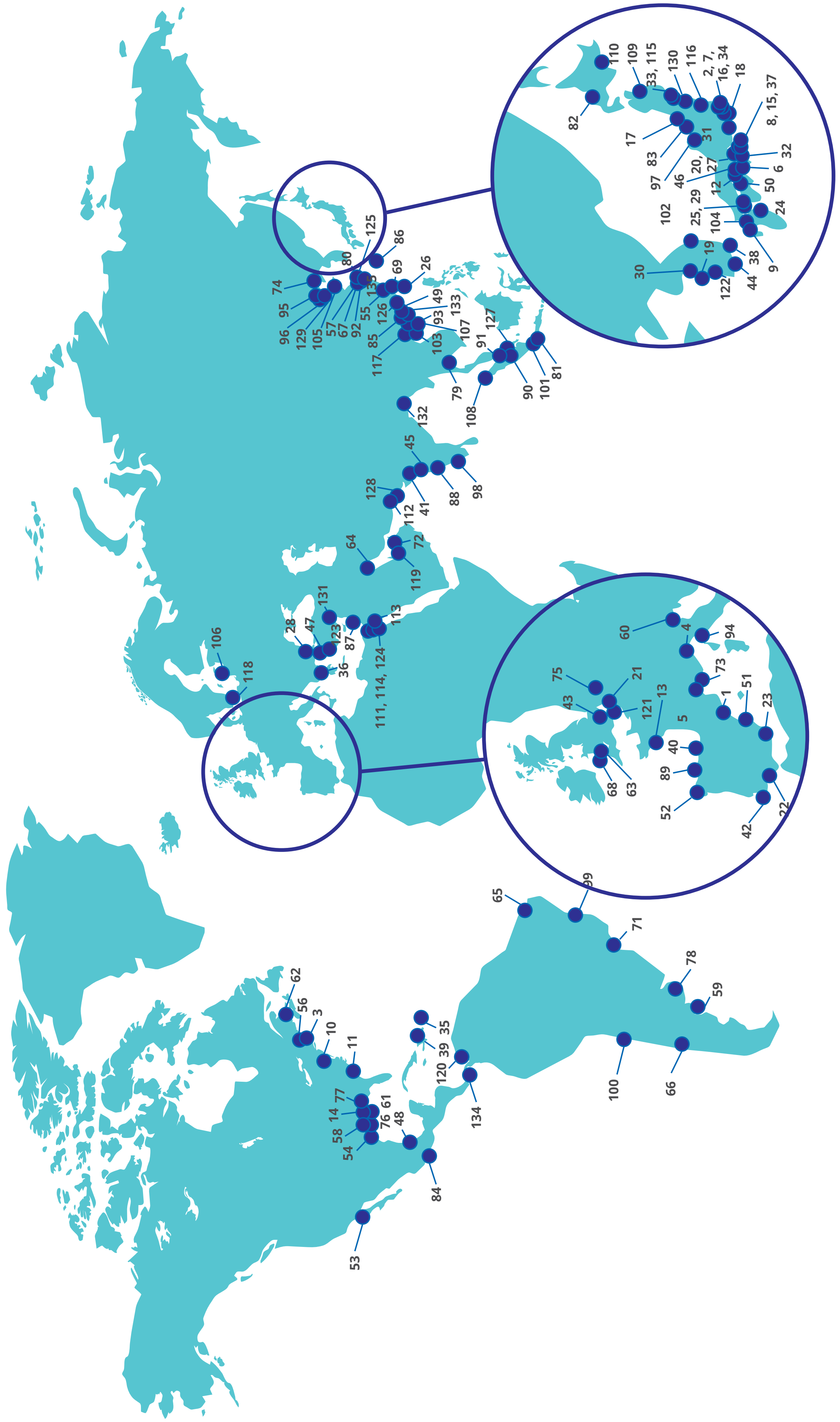


Figure 6.12: Global LNG Receiving Terminal Locations

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

6.8 RISKS TO PROJECT DEVELOPMENT

Regasification terminal developers must often confront multiple difficulties in completing proposed terminal plans, some of which are different than those 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. Both FSRUs and onshore developments are tasked with circumventing comparable risks in order to move forward. However, unlike onshore terminals, FSRUs may be chartered on a short or medium-term basis and be later redeployed to serve a different market.

The extent to which the economics of regasification projects work are often a combination of the ability to take on risk, or mitigate risks, as well as the ability to add or extract value from parts of the chain.

Risks and factors that determine economic and commercial viability of regasification projects include:

Project and equity financing
Historically, projects have faced delays as a result of financing challenges. These challenges can arise from the perceived risk profile of the partners, of the market in which the project is to be located, as well as of the capacity owners. Creditworthiness of parties involved will determine the ability to get financing, however, aggregators and traders can to some extent help take on these risks and lower the perceived liabilities to the bank.

Regulatory and fiscal regime
New regasification terminals can face significant delays in markets with complicated government approval processes or lengthy permit authorization periods. New terminals can also be hampered by the lack of an adequate regulatory framework or by detrimental fiscal regimes. Some markets also have incumbents with strong control over infrastructure and import facilities, which despite liberalisation trajectories, gives them some control over capacity and profitability of parties looking to participate in that market.

Challenging site-related conditions
In specific geographical areas, technical conditions and/or environmental conditions can lead to additional costs, delays or cancellations of regasification projects. An examples is weather disturbances that cause construction delays.

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. Part of this responsibility lies with the contractor – to ensure documentation and applications are prepared in time, but also with governments, to set clear and efficient processes, and communicate these clearly. Examples of delays have been caused by visa delays, and delays in approvals of permits due to in-complete submissions.

Securing long-term regasification and offtake contracts
Terminal capacity holders and downstream consumers will need to be contracted for an FID to be taken, particularly as the market shifts toward shorter-term contracting. For the development of new terminals, political support could be needed if long-term commitments are not secured. Parties need to agree a sharing of some of the remaining risks when not all capacity or offtake has been contracted in time for a competitive investment decision. Uncertainty in demand outlook, or significant unexpected changes in the demand outlook will cause delays or cancellation of regasification projects. Increased scalability of regasification facilities will help to some extent.

Access to downstream market and availability of downstream infrastructure
Pipelines or power plant construction that are required to connect a terminal with end-users are often separate infrastructure projects that are not planned and executed by the terminal owners themselves. The misalignment of timelines between the projects, or lack of infrastructure development downstream of the terminal can cause under-utilization of facilities or delays in start-up.

UGCC - Courtesy of KOGAS

7. The LNG Industry in Years Ahead

1 Will the 4 FIDs taken in 2018 spur a new wave of liquefaction investment to come on line post 2023?

The 4 FIDs seen in 2018 (Corpus Christi LNG Train 3, LNG Canada, Greater Tortue FLNG and Tango FLNG) demonstrate that parties take FIDs on the basis of different risk appetites – not all those projects were underpinned by long term offtake agreements at the time of FID. This trend is likely to continue in 2019, and the industry may see that parties who do not require external financing to develop facilities, will be able to proceed without long term agreements in place. This means that contracting progress is not the only indication of progress towards FID.

Another aspect that will shape appetite for new project sanctioning in 2019 is that new market entrants in LNG export from Canada and Africa are intending to take advantage of the increasing commoditization of LNG and trade to diverse markets including China, India and other developing economies. Indeed, these events may portend a restart of liquefaction investment to meet what is expected to be a redeveloping gap in supply to meet growing demand in the mid-2020s.

For example, the scale and aggressive timeline of the LNG Canada project may be the first indication of a move toward rapid development of Western Canada LNG projects to take advantage of the expected continued growth in the Chinese gas market, and world demand growth generally, and to respond to other exporters interested in capturing this growth. Current projects underway and existing capacities will be strained into the early 2020s, and while several significant global players will be on track for capacity expansion to meet this expected continuing demand growth, renewed opportunities for green field projects are expected to emerge. For Western Canada and Alaska, proximity to the Chinese market has particular attraction for accelerated development of projects there.

Another aspect that will drive appetite for FIDs is perceived competitiveness of supplies out of projects. Brownfield developments, and those with access to low cost upstream gas have been able to demonstrate progress in 2018 that could position them for an FID in 2019. Progress in late 2018 and early 2019 on contracting supplies out of Mozambique and other new entrants suggests that momentum on new liquefaction development is proceeding, at least in certain regions and particularly in Africa where new natural gas supplies and needs to monetize those supplies represent distinct opportunities for national governments. Timing of these development interests and expectations in developing market needs for additional supplies appear to be in alignment to justify new projects.

2 What will be the role of Russia in future LNG supply?

LNG export from Russia is poised to grow significantly and perhaps challenge Australia and Qatar for global leadership in liquefaction capacity. The opening up of the Arctic as a frontier LNG export region, and the ability to export LNG through the Northern Sea route mean LNG from Russia can now reach more markets competitively.

After a slow start to developing Russia's frontier Arctic region, building upon its experience with its Yamal facility, Novatek is rolling out a strategy with an eye to expanding Russian Arctic production to a scale mirroring Qatar's export business, with completion of Arctic LNG 2. The intent is to bring this additional capacity on line by 2023 or earlier, assuming an FID will be taken in 2019. This scale of LNG production in the Arctic may be the start of a new wave of LNG, after Arctic production historically struggled to demonstrate that it could overcome the numerous challenges of running liquefaction facilities and operating carriers in the Arctic.

While current contracting is mostly long-term and oil index-priced, that approach may change as new Arctic capacity is brought on line with players who have the ability to take some of the offtake risk. Novatek forecasts for capacity additions with completion of all trains planned for Yamal and Arctic LNG 2, plus existing capacity at Sakhalin among other projects, would place it as the leading exporter of LNG, surpassing its current rank as fourth in world liquefaction capacity.

Technical aspects of Arctic development will remain key drivers for capacity expansion, notably exploitation of the Northern Sea Route through use of ice-class LNG carriers and trans-shipment technologies and strategies. Russian LNG, long thought to be plays for the Northern European market, may turn out to have longer reach into higher demand markets, including China with the opening up of the Northern Sea route for LNG.

A potential constraint for further LNG export development from Russia may come from Russia's international trade in pipeline natural gas. Russia's pipeline projects to China, including the Altai Pipeline and Power of Siberia projects, may develop into gas-to-gas competition within the Russian export market and slow further LNG project activity.

3 How will build out of the LNG carrier fleet proceed?

Orders for new LNG carriers are the highest they have been since 2014, edged on by high spot charter rates, relatively low new build costs, and robust transportation growth. Builders, having been careful to avoid over-building until recently, have been unable to resist these incentives for new vessels, which are going to new market entrants as well as established LNG market participants. Along the way, new builders have also entered the market. Incentives to construct new LNG carriers are such that at least one-third of the vessel order book do not have any clear charter business, meaning they are speculative builds.

Older vessels continue to hold value as LNG carriers, where some may have thought their futures were as conversions to FSRUs and other vessel types. Decommissioning and scrapping of LNG carriers has not kept pace in retiring potentially obsolete vessels to make way for new vessels. Some laid up capacity has resumed operation as charter rates have become higher. Increase in new builds will incentivize scrapping older vessels, but as U. S. exports ramp up and needs to serve longer routes increase, these older vessels may play a renewed role in the trade.

While ice class vessel orders have been predicted to increase during the next few years due to the increased production of LNG in the Arctic region, the need for regular LNG carriers will also increase, This is to keep pace with the increased amount of trans-shipment operations in the Northern seas, to shorten the routes of the ice class vessels due to their lower max speed. This would also increase the demand for new modern LNG carriers with properties better adjusted for safe and sustainable trans-shipment operations.

Upward pressure on new build prices is being observed after several years of stability due to vessel supplies and moderated LNG demand. Those underlying conditions are changing, however, and have put upward pressure on prices. Ultimately, charter rates will also be influenced by Basin imbalances, use of swaps to maintain balances, vessel availability, and digitalization of trade data.

4 What factors will influence Chinese LNG demand?

Recent moderation of growth in the Chinese economy, caused by a variety of factors, is likely to have short-term impacts on LNG demand growth. However, as the Chinese economy continues to modernize and replace coal and other energy resources with natural gas, LNG will continue to be the principal dynamic and balancing energy resource in China. Fundamentals for the Chinese economy and prospects for growth are expected to remain strong over the long run, especially as domestic Chinese consumer incomes and consumption patterns increase.

The pace of governmental efforts to switch out coal-fired power generation for natural gas-fired generation will continue to have a major impact upon LNG demand. In recent years, expansion of coal-fired generation has occurred at the expense of potential increased use of natural gas-fired generation, but this trend was principally determined by regional power needs and associated location of generation assets. As China builds out its natural gas infrastructure, switching to natural gas-fired generation may accelerate in these regional power markets.

Gas-to-gas competition in China has yet to emerge in any significant way, but as domestic production takes on a greater role, and more importantly pipeline imports of natural gas from Russia, LNG will have to compete for emerging energy demand. The impact of these sources and the rate of their deployment, too, will depend upon how fast the Chinese natural gas infrastructure is expanded.

5 What will be the role of small-scale floating receiving terminal capacity?

Sanctioning and implementation of FSRU projects will continue to play an important role in energy delivery, especially in new markets for natural gas, used to either repower electrical generation or meet general consumer energy needs. Of course, an FSRU deployment strategy is likely to face limits in economically-efficient energy market expansions, and governments and energy industry players need to consider where a transition to full scale, land-based LNG import terminals is warranted.

It is expected that small-scale floating systems growth will be used to support power generation and, specifically, as gas-to-power integrated units. This application is likely to dominate the roll-out of small-scale floating systems since they can provide the most cost-effective means of simultaneously addressing repowering of electrical systems and integrating the fuel delivery and supply function when switching to natural gas. As discussed in this report, gas-to-power strategies represent one of the most vibrant areas of technological development since projects need to simultaneously address challenges of LNG storage, floating regasification technologies, vessel design, and regulatory classification and siting.

Small-scale floating projects are likely to emerge as a niche solution to various issues in energy demand, such as industrial customers requiring stable and high-compositional quality natural gas, isolated markets and to address various regulatory and logistical limits on pipeline supplies. New technologies, such as those discussed earlier in this report and including containerized delivery of LNG, are expected to play a greater role in these niche opportunities. Many of these niches might never grow in scale to support traditional land-based terminal operations, and in many areas continuing regulatory challenges may continue to hamper onshore terminal construction. As a result, continuing innovation to serve these markets is likely to receive great attention.

6 What is the future for nuclear power generation in Northeast Asia and how will it impact LNG?

The restart of some idled Japanese nuclear power stations has initially resulted in a significant decline in LNG demand as shown in data for 2018, but the pace of decline in the future is difficult to predict. A plan issued by Japan's Ministry of Energy, Trade and Industry (METI) includes a continued role for natural gas in Japan's energy mix. The role for natural gas role in the long-term is not as clear, as growth in renewable energy has also been significant. Nuclear plant restarts coupled with other pressures on LNG demand, including increases in end use energy efficiency and increasing requirements for reducing carbon fuel use to meet climate goals, may perpetuate declines in LNG demand.

Energy policies in Korea have had similar effects as they grapple with regulatory reforms and contingencies such as the potential to import pipeline supplies from Russia. Collectively, these pressures have led to a decline in Northeast Asian LNG demand growth. However, with the phasing out of nuclear power in South Korea and Chinese Taipei, the gap in energy supply sources suggests a continuing role for LNG and perhaps growth in LNG demand. It is unclear whether the experience of Japan involving increased energy efficiency and renewable energy growth will be experienced in these markets.

7 How will international efforts to limit methane emissions as part of greenhouse gas reduction strategies affect LNG?

According to many climate scientists, methane from natural processes and industrial emissions may represent a powerful contributor to total greenhouse gas (GHG) atmospheric concentrations and climate change. As international accords on climate change enter the implementation stage with respect to industrial emissions of GHGs, increasing attention to the natural gas chain as a source of methane emissions is inevitable. Accurate data on actual natural gas emission rates and underlying emissions will continue to play a role in developing international, national, and local policies regarding emission controls in the near term. However, it is clear the LNG industry as a significantly-growing segment of the natural gas chain will have to assume a more direct role in assessing its contribution to methane emissions and prepare to take steps to reduce emissions wherever possible.

It is in the direct economic interest of the LNG industry to reduce methane emissions as a portion of its natural gas throughput, toward a target of zero emissions. For LNG plant operators, having sustainable and low-emitting facilities go hand-in-hand with good operating practices. Going forward, the LNG industry needs to communicate clearly to public stakeholders about these complementary interests while it continues to develop monitoring technologies to assess the extent of facility emissions and control strategies to deal with known emission sources.

It is clear that natural gas presents significant environmental advantages as a fossil fuel, and LNG supports that environmental advantage in meeting world energy needs. The LNG industry must continue to advocate its case for use in the world energy mix and distinguish its environmental performance from other energy forms and industries. Also, the LNG industry must continue to develop new approaches to address the source of its feedstock as a means of addressing methane emissions. "Bio-LNG," discussed later in this chapter as a new technological effort offering promise, is one such approach.

Beyond more traditional LNG operations, methane emissions from internal combustion engines known as "methane slip", as part of total hydrocarbon emissions, is gaining increased scrutiny from stakeholders looking at LNG's contribution to atmospheric methane from human sources. This source is most important in the use of LNG as a marine vessel fuel. Also, vessel bunkering operations involving the connection and disconnection of fueling lines is seen by some parties as an issue. Both of these sources of methane from LNG might be expected to grow as LNG vessels become more common in shipping. However, technologies to minimize these sources are on the horizon and need to be deployed to help move towards expansion of the LNG vessel fleet.

8 What changes and influences might support faster roll out of LNG bunkering projects?

Under current bunker fuel market conditions, the costs of alternatives to high-sulfur fuels and emission mitigation approaches give LNG an advantage for meeting IMO-driven emissions regulations. In the future, regulation of oxides of nitrogen in vessel emissions will play a role, but sulfur emissions criteria will dominate decision making regarding bunker fuels. A key factor in this emissions limit-based driver for the bunkering market will be adherence to the current IMO timetables, especially as deadlines for compliance approach in critical markets such as the Mediterranean Sea and inland waterways covered by local governmental administration of the IMO limits.

Real and potential barriers to more rapid development of LNG bunkering include a lack of a clear regulatory framework for facilities, equipment, and port operations, including vessel maneuvering. These fundamental safety-related needs have been addressed regionally, as in Europe, and on a piecemeal basis, as in North America. However, since many potentially LNG-fueled vessels cross jurisdictional boundaries, greater consistency in technology and operations practices is needed. Greater development and adoption of International Standards Organization (ISO) requirements is needed to alleviate these impediments to growth. However, many jurisdictions will need to go further with coordination of facility and port requirements to help ensure that safe operation of LNG-fueled vessels is maintained.

Beyond ISO and jurisdictional rule developments, standards development organizations (SDOs) have stepped forward to initiate other consensus-based standards for bunkering facilities and those may be adopted outside of jurisdictions that traditionally refer to ISO standards. These standards-development activities, while needing to be consistent with ISO coverage, should be encouraged to support more rapid deployment of bunkering technologies.

With respect to technology development, bunkering could be accelerated by greater design consistency of fueling equipment and practices, development of more modular and scalable approaches to meet growing fleet needs, and development of consistent fuel quality standards and storage that meet both the needs of engine manufacturers and fuel suppliers.

9 What innovations and technologies will be needed to support further development of LNG?

Innovations in commercial aspects of the traditional LNG chain are needed to accomplish more equitable risk allocation among market participants, including producers, shippers, consumers, and governments. Today, imbalances in the risks facing new projects, in particular, create impediments to project development and execution. For example, with respect to new liquefaction projects, risks associated with offtake for project developers may continue to impose crucial disincentives to projects. Going forward, a need exists to develop collaborative models for commercial agreements involving commercial interests, the banking industry and governmental authorities (including local as well as national governments). Local regulatory and incentives, in particular, present opportunities to expedite LNG project development. Positive approaches at this level should be promoted.

In terms of technologies, increased flexibility to produce and accept various compositional specifications of LNG is needed to enhance market liquidity and competitiveness of LNG generally compared to other primary energy forms. This will require greater levels of capital expenditure at export facilities and receiving terminals, but expiries of long term supply contracts may provide an important opportunity to time projects to accomplish this. Increased digitalization of the industry would also contribute to greater competitiveness by improving plant efficiencies and lowering plant operating costs.

Over the longer run, technologies and efficiencies will need to address methane emissions from the LNG value chain. Energy efficiency of existing operations and in new plants will play a key role in reducing overall carbon emissions, while carbon capture and utilization approaches further reduce the carbon footprint of LNG. It is anticipated the biogas and its utilization to produce "bio-LNG" will play a role in the future, and while up to this point having been seen as a very long-term opportunity, its development could accelerate as carbon emissions control programs are implemented.

8. Small scale and LNG bunkering with special emphasis on ship to ship bunkering

Coralius - Courtesy of Sirius Shipping

Increasing environmental regulation worldwide, and locally in Europe, the US, and China, makes LNG a natural fuel of choice in a variety of sectors, including power generation, industrial use, and marine transportation. However, the adoption of LNG as fuel depends on an efficient, secure and competitive LNG supply chain and related infrastructure.

A specific small-scale market focus on bunkering LNG to ships, that have the ability to use LNG as fuel, has developed in the last few years. Ship to ship (STS) and truck to ship bunkering therefore seems to be an obvious requirement for the adoption of LNG as fuel for ships globally.

Although the LNG bunkering market developed early in 2002 regionally in Norway, to deliver this new bunker fuel to small ships, such as platform supply vessels, fishing vessels and coastal ferries, the environmental regulations put in place by international and local regulatory bodies are driving shipowners to build new ships or convert the existing ones to LNG fuel, displacing other bunker fuels.

Many LNG bunkering projects have been developed based on truck to ship or tank to ship installation years before the scheduled entry into force of the International Maritime Organization (IMO) ban to burn fuels on board of ships with sulphur content higher than 0.5%, and thanks to the availability of LNG in regions that have been directly affected by local regulations to prevent air pollution such as Europe and the USA.

These days the bunker capacity of new projects, especially newbuilds, also requires larger capacity LNG bunkers, which makes delivery of fuel from a significant number of LNG trailers commercially less attractive.

There has been a clear evolution since the first LNG bunkering projects of few thousands of cubic meters to the recent ultra large container ships ordered by CMA-CGM with a total LNG fuel capacity of 18,600 cm.

LNG ship to ship (STS) bunkering has been based on a large number of STS transfers in the LNG carrier segment, and this was first developed in the port of Stockholm between the SEAGAS bunkering barge (180 cm capacity) and a large ferry ship, the Viking Grace, in 2013. This is a project with a high frequency of bunkering operations, considering that the ferry has a 24 h sailing time between Stockholm and Turku. There is limited storage on board the ferry - two tanks each of approximately 200 cm. This project is a very specific example of LNG Bunkering since the SEAGAS barge is not being loaded at a small-scale LNG terminal but by trucks in another location of Stockholm port, the trucks being loaded in the Swedish small-scale LNG terminal of Brunnsviksholmen (Nynäshamn), in operation since 2011. Another specificity of this project is that the bunkering barge is a conversion of an old coastal ferry, imposing limitations to achieve a bespoke LNG bunkering ship, such as the LNG tank capacity for instance.

Small scale LNG carriers built in European, Japanese and Chinese yards have entered into service since the early nineties with capacities ranging from 1,000 to 20,000 cm, but none have been specifically designed and built for STS LNG bunkering operations. The list of such small-scale ships is included here below.

Table 8.1 Small-scale LNG vessels

IMO No.	Name	Builder	Shipowner	CAP. (m3)	Delivery
9275074	PIONEER KNUTSEN	Biljma	Knutsen	1100	2004
9675200	KAKUYU MARU	Higaki Zosen K.K.	Tsurumi Sunmarine Co Ltd	1500	2013
9260603	SHINJU MARU NO. 1	Higaki Zosen K.K.	Shinwa Chemical Co.	2500	2003
9317200	NORTH PIONEER	Shin Kurushima Dockyard Co. Ltd.	Iino Gas Transport	2500	2005
9433884	SHINJU MARU NO. 2	Higaki Zosen K.K.	Shinwa Chemical Co.	2500	2008
9469235	KAKUREI MARU	Higaki Zosen K.K.	Tsurumi Sunmarine Co Ltd	2500	2008
9554729	AKEBONO MARU	Higaki Zosen K.K.	Chuo Kaiun KK	3500	2011
9625140	CORAL ANTHELIA	Avic Dingheng	Anthony Veder	6500	2013
9378278	NORGAS INNOVATION	Taizhou Wuzhou Shipbuilding Industry Co	Norgas Carriers	10000	2010
9378280	NORGAS CREATION	Taizhou Wuzhou Shipbuilding Industry Co	Norgas Carriers	10000	2010
9378292	NORGAS INVENTION	Taizhou Wuzhou Shipbuilding Industry Co	Norgas Carriers	10000	2011
9378307	NORGAS CONCEPTION	Taizhou Wuzhou Shipbuilding Industry Co	Norgas Carriers	10000	2011
9468437	NORGAS UNIKUM	Avic Dingheng Shipbuilding Co Ltd	Norgas Carriers	12000	2011
9468449	BAHRAIN VISION	Avic Dingheng Shipbuilding Co Ltd	Norgas Carriers	12000	2011
9738569	HUA XIANG 8	Jiangsu Qidong Fengshun HI	Zhejiang Huaxiang Shipping	14000	2016
9617698	CORAL ENERGY	Meyer Werft	Anthony Veder	15600	2013
9783124	CORAL ENERGICE	Neptun Werft	Anthony Veder	18000	2018
9161510	AMAN HAKATA	NKKK Tsu	MISC	18800	1998
9016492	LUCIA AMBITION (Ex-AMAN BINTULU)	NKKK Tsu	MISC	18928	1993
9134323	AMAN SENDAI	NKKK Tsu	MISC	18928	1997
9349942	SUN ARROWS	KHI	MOL	19100	2007
9060534	SURYA AKI	KHI	Humpuss Consortium	19474	1996
9187356	TRIPUTRA (Ex-SURYA SATSUMA)	NKKK Tsu	Humpuss Consortium	23096	2000
9685425	JS INEOS INSIGHT	Nantong Sinopacific Offshore	EVERGAS	27500	2015
9685437	JS INEOS INGENUITY	Nantong Sinopacific Offshore	EVERGAS	27500	2015
9685449	JS INEOS INTREPID	Nantong Sinopacific Offshore	EVERGAS	27500	2015
9685451	JS INEOS INSPIRATION	Nantong Sinopacific Offshore	EVERGAS	27500	2016
9744958	JS INEOS INNOVATION	Nantong Sinopacific Offshore	EVERGAS	27500	2016
9744960	JS INEOS INDEPENDENCE	Nantong Sinopacific Offshore	EVERGAS	27500	2017
9771511	JS INEOS INVENTION	Jiangsu New Yangzi	EVERGAS	27500	2017
9771523	JS INEOS INTUITION	Jiangsu New Yangzi	EVERGAS	27500	2017
9693719	XINLE 30	Ningbo Xinle Shipbuilding	Zhejiang Yuanhe Shpg Co Ltd	30000	2018
9696266	HAI YANG SHI YOU 301	Jiangnan Shipyard Group Co Ltd	Offshore Oil Yangjiang Ent	30720	2015

The first real purpose design and built ship, capable of these types of LNG bunkering operations, is the Engie Zeebrugge. The 5,100 cm ship, delivered by Hanjin Heavy Industries to a joint venture of Engie, NYK, Mitsubishi Corporation and Fluxys in 2017, entered into operation early that year to deliver the bunker to car carriers in the port of Zeebrugge. Managed by NYK, the ship is also expected to deliver LNG fuel to other ports in the region, as the demand for LNG is increasing significantly.

Immediately following this development, others such as the 6,500 cm Cardissa, the 5,800 cm Coralius, and more recently the 7,500 cm Kairos have entered into service in Northern Europe, which has been pioneering commissioning of these type of projects. This makes sense considering the proximity to LNG terminals and the fact that some of these terminals have been also modified to provide LNG to small scale ships such as the Gate terminal in Rotterdam. The Cardissa will be operated in Rotterdam port, the Coralius at the entrance of the Baltic sea and the Kairos inside the Baltic. Loading terminals and clients to receive the bunker fuel are different case by case.

Another interesting development has been the conversion and upgrading of ships to enable LNG bunkering. Examples in this category are the Coral Methane and the Oizmendi. The Coral Methane is a small-scale LNG carrier of 7,500 cm delivered by Remontowa shipyard to Anthony Veder, which was recently upgraded to give the required flexibility to deliver LNG to gas fuelled ships. Minor adaptations of the LNG transfer system and the installation of a sub-cooling system for the LNG were considered in 2018. The ship is expected to be operated in Rotterdam port.

The second example is the Oizmendi, a HFO/MDO bunkering tanker which was converted in the first half of 2018, into a multifuel bunker ship; including two LNG tanks on the main deck to provide just 660 cm by STS. The ship will cover bunkering operations in the Iberian Peninsula.

Table 8.2: Active bunkering ships, newbuilt or conversions:

IMO No.	Name_of_Ship	Builder	Shipowner	CAP. (m3)	Delivery
7382691	SEAGAS	Loland Verft AS	AGA GAS AB	180	1974
9494981	OIZMENDI	Cardama	Itsas Gas Bunker Supply	660	2009
9404584	CORAL METHANE	Remontowa	Anthony Veder	7500	2009
9750024	ENGIE ZEEBRUGGE	Hanjin H.I.	LNG Link Investment AS	5000	2017
9769128	CORALIUS	Royal Bodewes	Sirius Veder AB	5800	2017
9765079	CARDISSA	STX Offshore & Shbldg - Jinhae	Shell Western LNG BV	6500	2017
9819882	KAIROS	HMD	Babcock Schulte Energy	7500	2018

The above list does not contain a 2,200 cm bunkering barge (non-propelled unit) built in the US, specifically for LNG bunkering of TOTE containerships. This was built locally in the COMRAD shipyard with membrane Mark III technology, the first ever of this type.

Among the twelve newbuild projects confirmed at the end of 2018, capacities range from 3,500 to 18,600 cm.

The technology typically installed in this new generation of ships for LNG containment is the type C cylindrical. Membrane technology also appears to be of interest in some new projects, when cargo capacity under discussion is above 10,000 cm: the first and largest ever LNG bunkering ship presently under construction at Hudong-Zhongua shipyard in China for MOL, will be equipped with 2 LNG Mark III flex containment systems with a total capacity of 18,600 cm.

The above being said, considering port limitations and ship manoeuvrability, it seems reasonable to assume that the cargo capacity of new LNG bunkering ships will likely be kept below 10,000 cm in most cases. This would lead to an increased number of LNG bunkering operations when taking into account the expected demand of LNG as fuel.

In terms of engine and propulsion solutions, dual-fuel engines (for propulsion and electrical generation) and conventional propellers could well be the choice for small ships. This is largely driven by environmental regulations and previous experiences in the LNG carrier segment with different technologies. However, in some specific cases azimuthal propulsion will lead to increased manoeuvrability and reduced collision risks during operations inside ports. In addition, transversal propellers have been installed in most cases where the LNG bunkering ship is not equipped with azimuthal propulsion.

Different LNG transfer systems have been proposed for existing or on-order LNG Bunkering ships. Most of the designs have considered flexible hoses handled by cargo hose cranes and suitable emergency release couplings (ERC) and quick connection/disconnection couplings (QCDC) which offer safe connections to prevent LNG leaks. However, a tailor-made LNG transfer system was installed on board of the Cardissa LNG bunkering ship, based on an LNG loading arm suitably designed for LNG bunkering operations.

With regards to the evolution of shore small scale LNG installations that can provide bunker fuel, these are wide spread in Europe and the USA, and progressively being constructed in other parts of the world.

Small-scale LNG production and regasification facilities in Norway, which facilitate the distribution of LNG to bunkering stations, ships or trucks, include those located at Tjeldbergodden, Kollsnes, Karmøy, Øra and Risavika, with Statoil, Skangass and Shell (Gasnor) being the main developers.

In particular, the Risavika plant south of Stavanger is the newest liquefaction facility in Norway, and possibly the most important in terms of bunkering because of its storage capacity (30,000 cm). Small- scale LNG carriers use this facility with great regularity and some LNG bunkering operations have already been carried out terminal to ship.

Storage and bunkering stations already in operation include: Naturgass Møre in Alesund, Sunndalsøra (Gasnor-Shell), Høyanger, Mosjøen, Ågotness Coast Centre Base (CCB), Halhjem terminal, and Florø (Saga Fjordbase). Many of these have already been used for truck-to-ship or shore-to-ship LNG bunker operations. In addition, Skangass secured a permit early in 2014 to build a dedicated LNG bunkering station in Risavika for the Fjord Line ferries operating between Stavanger, Bergen and Hirtshals (Denmark). This bunker facility was commissioned in June 2015.

As mentioned above, AGA commissioned the Brunnsviksholmen (Nynäshamn) regasification terminal, located South of Stockholm, in 2011. Also in Sweden, the Coralius ship is used to load at Lysekil and deliver the bunker fuel at the entrance to the Baltic Sea.

Pacific Breeze - Courtesy Of Inpex

Gothenburg port has already confirmed that it is heavily involved in the development of LNG bunkering facilities and bunkering procedures.

Some new LNG import terminals were commissioned in Finland. As an example, Skangass chose the Western Finnish port of Pori as the location for its first LNG import terminal. The Northern Tornio Manga LNG-receiving terminal unloaded its first shipment of LNG back in November 2017, taking delivery of a 15,000 cm cargo delivered from the Skangas-chartered Coral Energy small scale LNG carrier.

A more recent operation linked to the LNG bunkering market took place in January 2019 from the FSRU Independence in Lithuania to the LNG bunkering ship Kairos.

Shore to ship bunkering operations have already been carried out in Hirtshals (Denmark) for Fjordline ferry ships operating between Norway and Denmark.

Various plans to build LNG bunkering stations have been reported elsewhere in recent months, mainly in Northern Europe. In particular, the Rotterdam and Zeebrugge LNG terminals currently have specific small-scale facilities to load such small ships. Grain LNG terminal East of London is studying different options for the implementation of break-bulk facilities, to be able to reload small-scale LNG carriers and supply LNG to trucks. France, Spain, Italy and Greece are developing projects as well. In Spain, adjustments have been made to the LNG terminal of Barcelona to be able to handle both large and small-scale vessels, and in Cartagena studies of transshipment operations in the port have been undertaken.

In the USA, infrastructure is available in Port Fourchon for Harvey Gulf platform support vessels and Jacksonville, for truck to ship and soon ship to ship, using the COMRAD built barge. At least two more articulated tug barges are under construction, of 4,000 and 8,000 cm capacity respectively. LNG bunkering of Carnival cruise ships in Florida is also foreseen.

Outside the USA and Europe, infrastructure for LNG is available in many locations such as the Middle East, Singapore, Malaysia, Japan, China, South Korea and Australia, demonstrating that small scale infrastructure development is progressing. As an example of the developments in these markets, Excelerate Energy at Jebel Ali in Dubai is able to deliver bunker fuel through an LNG bunkering manifold on board of the FSRU. Similarly, China is presently building its first national LNG bunkering ship project for ENN Energy, and Japan is developing a project for Central LNG Shipping.

The evolution of the gas fuel fleet has been slow, but large ships are expected to be delivered from 2020. At the end of 2018 a total number of 140 ships using LNG as fuel were in service, with over 160 ships on order, including at least 35 large tonnage ships. These include ultra large container ships, ore carriers and aframax tankers.

Although global small-scale production is estimated at around 25 MTPA with potential for growth of more than 6% per year, a figure slightly above ten percent of the global production is forecasted to be used as a bunker fuel in 2020, i.e. in the range of 3 MTPA. As an example, Total and CMA CGM have signed an agreement covering the supply of around 0.3 MTPA of LNG per year for a period of 10 years starting in 2020, when nine ultra large container ships presently under construction are scheduled to be delivered. Further predictions are that by 2030 a figure of slightly above 25 MTPA will be dedicated to LNG as marine bunker fuel.

Further regional small scale markets will be developed because of new local regulations. As an example, virtual LNG pipelines have been already developed in Portugal and USA. Both are based on ISO containerized transportation of LNG by ship. The Gaslink project in Portugal between the Sines and Lisbon ports and Madeira Island is in operation since 2014, and has transported an average 25 containers per week. In March, Hawaii Gas received approval from the Hawai'i Public Utilities Commission (PUC) to use LNG in limited quantities as a backup fuel for its O'ahu synthetic natural gas operations. Its first shipment of containerized LNG arrived in April. In addition, Hawaiian Electric reached a deal with Fortis B. C. to import up to 0.8 MTPA of LNG for 15 years starting in 2017. Other terrestrial virtual pipeline projects have been developed involving transportation of ISO LNG containers by ship, train and truck. In Spain, a multimodal transport pilot project was completed at the beginning of 2018, consisting of transporting an ISO container of LNG from the LNG terminal in Huelva in Spain by road, rail and ship to Melilla.

9. Floating LNG

There are two different applications of floating LNG (FLNG): floating, production, storage and offloading units (LNG FPSO); and floating, storage and regasification units (FSRU). FLNG facilities are a relatively new concept, with very few in operation today, but it is realising its potential, with different technology solutions for different developments. FSRU concepts have been deployed regularly and successfully around the world over the last 10 years; advantages can include speed and affordability/ scalability when local demand is small or new, and development of an onshore terminal is challenging.

Shell Prelude - Courtesy of Shell

LNG FPSO

LNG FPSO have traditionally been referred to as FLNG, and there are few applications in the world to date. In fact, these concepts are small scale applications in any case, with production capacities ranging from 0.5 to 3.6 MTPA. LNG FPSO have been discussed for decades, since the first concept of a barge was developed in the fifties.

There are several arguments to support the development of LNG FPSO – for instance, the development of offshore gas fields with no pipeline connection to shore, limitations for LNG carriers to access a waterfront facility or difficulties in developing an onshore terminal.

Recently, different concepts involving newbuild units and conversions have been developed. Although LNG FPSO are not usually considered fast track projects, an advantage is that the units can be relocated. The relocation may however involve modifications to the gas treatment facilities, liquefaction facilities, anchoring and other systems.

An LNG FPSO facility is usually built in a shipyard, which allows for cost savings when compared to the construction of a conventional onshore liquefaction terminal.

Offshore LNG FPSO facilities may be exposed to harsh met ocean conditions. The concepts are usually equipped with weather-vaning anchoring and dynamic position systems. Such type of LNG FPSO will also require LNG offloading based on ship to ship (units moored alongside) or tandem configurations.

Units operated in more protected areas, such as near to shore or near ports, are used to produce LNG from onshore gas and eventually maybe offshore gas, supplied by a short pipeline. The locations have relatively benign water conditions since they are usually not exposed to open seas. Because they are located near shore, transfer of personnel and equipment is easier, and the accommodation and service facilities on board can therefore be limited, reducing the total CAPEX of the installation. In addition, the mooring equipment may be similar to a permanent mooring system for a floating installation or ship into a jetty which also reduces the cost of the construction and installation.

Very few LNG FPSO have been converted LNG carriers, the main advantage being the time required for the commissioning of the unit. A conversion project in most of cases will require less capital cost and will involve shorter time schedules, making it suitable for an area where a fast fuel switch is required. On the other hand, new build units can be tailor made, designed for a specific gas field and prepared to be relocated.

Under Construction or in Operation LNG FPSO projects

Market	Developer	Project	MTPA	cm	Start-Up
Malaysia	Petronas	PFLNG Satu, Kanowit Field	1.2	354,000	2017
Australia	Shell	Prelude	3.6	437,500	2018
Cameroon	SNH/Perenco/Golar LNG	Kribi (Golar Hilli)	1.2	125,000	2018
Equatorial Guinea[1]	Ophir	Fortuna (Golar Gandria)	2.2	125,000	2019
Malaysia	Petronas	PFLNG2, Rotan Field	1.5	177,000	2020
Mozambique	ENI	Coral South	3.4	230,000	2020
Argentina[2]	Exmar	Tango FLNG	0.5	16,500	2019
Senegal	BP	Greater Tortue	2.4	125,000	

Note: Sources IGU Work Report "FLNG Concepts. Facts and Differentiators" dated June 2018 and others

Nowadays only three units, the Malaysia "PFLNG Satu", Shell "Prelude" and "Golar Hilli" are in operation. The other units are either under construction or under conversion.

[1] Golar Gandria LNG was proposed for conversion, but Ophir has lost the license
[2] The Exmar Caribbean FLNG will be relocated in Argentina to develop LNG exports

FSRU[3]

After more than 10 years of operations, FRSU solutions are considered a proven and reliable solution. FSRUs are also flexible since relocation after a period of operation in a single location is highly feasible. FSRUs have been seen as an advantageous alternative to onshore terminals, with the main benefits being the reduced cost and easier implementation. For instance, regulatory approvals may be less time consuming due to the lesser environmental impact.

In addition, units just for storage - so called floating storage units - have been deployed in different locations as the storage tank construction period onshore is lengthy in comparison to a ship or floater construction at a specialized shipyard. Floating storage units, in combination with onshore regas or other small-scale applications such as ship to ship LNG offloading, are presently used as well.

A conventional onshore terminal on the other hand, compared to any type of floating solution, has a greater gas storage capacity. This offers long-term supply security for the market and therefore provides a more permanent solution, while an FSRU can be classified as a more temporary solution.

Since regasification terminals are typically close to the consumers, the FSRU's are often installed inside a port or within a protected marine area. Indeed, near shore applications have been the common approach for FSRU because there are many advantages with regards to mooring systems and short distances to the gas grid or gas power plant. In addition, the design of the unit takes into consideration the mild met ocean conditions of the area as compared to an offshore location with a harsh sea environment.

The first FSRU was a newbuilt ship of 138,000 cm constructed by DSME (South Korea) for Excelerate, designed to offload gas on open sea conditions. This unit, delivered in 2005, was followed by other similar newbuilds which were equipped with the same type of regasification and mooring system, based on an internal turret and offloading buoy for the gas, which is connected to a subsea pipeline. This concept is still used in few locations and is called the "Gateway" concept. Another feature of this concept was that the units were weather-vaning moored to the buoy only during the offloading operations, typically less than ten days, and then disconnected and returned to the export LNG terminal to take another cargo.

Soon after this FSRU concept, jetty moored solutions were typically used in ports or protected areas, including rivers in South America, Europe and the Middle East.

Furthermore, the first FSRU vessel conversion was commissioned in 2008, followed by very few until the last one was commissioned in 2013. Old Moss type LNG carriers were converted for projects in Brazil, Indonesia and Italy for instance. Another more recent example of floating storage unit conversion is the Malta project, commissioned in 2017.

As to the comparison between conversion and newbuilds, CAPEX and OPEX considerations are leading parameters for decisions. Conversion of LNG carriers to FSRU's used to take less time than newbuilds and had higher feasibility from a CAPEX point of view. On the other hand, new builds may be more flexible and long lasting, and are therefore a particularly interesting solution for mid to long term projects. The limited capacity and the age of the potential candidates to be converted (LNG carriers of 20 to 40 years old, most of them of Moss tanks and steam turbines) in the range of 125,000 to 137,000 cm, may limit the number of FIDs for such types of conversions in the near future. In addition, Moss type LNG carriers may face an issue arranging the regasification facility in the cargo area because of its layout. When compared to an onshore conventional terminal, it generally requires lower operating expenditure (OPEX) than any of the FSRU solutions, but comes with a higher initial investment.

Despite the advantages of FSRU's versus onshore facilities, it is also clear that there are many challenges - such as a lack of clear local policies and regulations, a lack of infrastructure in remote or less developed markets, and commercial hurdles such as potential fluctuation of LNG demand. An example of the dynamism of the FSRU market is that markets may become exporters from a traditional import position and vice versa - examples being Egypt and Colombia. In some other locations regasification and liquefaction capacities co-exist.

The total FSRU capacity, in terms of regasification, is relevant when compared to global regasification capacity as it represents approximately 15% of the Global LNG regasification capacity. However, the utilization rate is lower, since for instance one third of the total modern fleet is actually operated as LNG carriers (approximately 10 units). Furthermore, it must be noted that to deploy these LNG carriers as import terminals, infrastructure construction would be needed onshore, such as pipeline, jetty, etc.

[3] Please also refer to 6.7

10.

References Used in the 2019 Edition

10.1 DATA COLLECTION

Data in the 2019 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 previous World LNG Reports, available on the IGU website at www.igu.org. No representations or warranties, express or implied, are made by the sponsors concerning the accuracy or completeness of the data and forecasts supplied under the report.

The IGU wishes to thank the following organisations and Task Force members entrusted to oversee the preparation and publication of this report:

- American Gas Association (AGA), USA: Ted Williams
- Australian Gas Industry Trust (AGIT), Australia: Geoff Hunter
- Bureau Veritas, France: Carlos Guerrero
- Enagás, Spain: Angel Rojo Blanco, Anne Rebecca Samuelsson
- GIIGNL, France: Vincent Demoury
- IHS Markit: Kelli Krasity, Gautam Sudhakar
- KOGAS, S. Korea: Soo Ock Shin, Youngkyun Kim, Sung-pyo Wi
- Osaka Gas, Japan: Tamotsu Manabe
- Shell: Birthe van Vliet, Chris Hay, Wouter Meiring

10.2 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 market in which a company is based.

Large-Scale vs. Small-Scale LNG: For the purposes of this report, IGU defines the large-scale LNG industry as every LNG business above 0.5 MTPA of LNG production and/or consumption. Conversely, small-scale LNG is any business under 0.5 MTPA.

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

LNG Carriers: For the purposes of this report, only Q-Class and conventional LNG vessels with a capacity greater than 30,000 cm are considered part of the global fleet discussed in the "LNG Carriers" chapter (Chapter 5). Vessels with a capacity of 30,000 cm or less 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. Sport 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
- Short- and medium-term trade together comprise non-long-term trade
- 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.

10.3 REGIONS AND BASINS

The IGU regions referred to throughout the report are defined as per the colour coded areas in the map above. The report also refers to three basins: Atlantic, Pacific and Middle East. The Atlantic Basin encompasses all markets that border the Atlantic Ocean or Mediterranean Sea, while the Pacific Basin refers to all markets bordering the Pacific and Indian Oceans. However, these two categories do not include the following markets, 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 markets with liquefaction or regasification activities in multiple basins and has adjusted the data accordingly.

10.4 ACRONYMS

BOG = Boil-Off Gas
CAPEX = Capital Expenditures
CBM = Coalbed methane
CO_2 = Carbon Dioxide
DES = Delivered Ex-Ship
DFDE = Dual-Fuel Diesel Electric
EPC = Engineering, Procurement and Construction
EU = European Union
FEED = Front-End Engineering and Design
FERC = Federal Energy Regulatory Commission
FID = Final Investment Decision
FOB = Free On Board
FLNG = Floating Liquefaction
FPSO = Floating Production, Storage, and Offloading
FSRU = Floating Storage and Regasification Unit
FSU = Former Soviet Union
HFO = Heavy Fuel Oil
HOA = Heads of Agreement
IOC = International Oil Company
IMO = International Maritime Organisation
ISO = International Organisation for Standardisation
JKT = Japan, South Korea, and Chinese Taipei
ME-GI = M-type, Electronically Controlled, Gas Injection
MDO = Marine Diesel Oil
MOU = Memorandum of Understanding
NBP = National Balancing Point
NIMBY = Not in My Backyard
NOC = National Oil Company
NOX = Nitrogen Oxides
NSR = North Sea Route
OPEX = Operating Expenditures
SO_x = Sulphur Oxides
SPA = Sales and Purchase Agreement
STS = Ship to ship
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, Hawaii, and Puerto Rico
YOY = Year-on-Year

10.5 UNITS

bbl = barrel
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

10.6 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		1,200	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	ADNOC LNG 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	ADNOC LNG 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, TOTAL	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, Naturgy, 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	Equinor, 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®

Appendix 1: Table of Global Liquefaction Plants (continued)

Reference Number	Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
21	Australia	Pluto LNG T1	2012	4.9	Woodside, Kansai Electric, Tokyo Gas	Shell propane pre-cooled mixed refrigerant design
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™
32	United States	Cove Point LNG	2018	5.25	Dominion	AP-C3MR/SplitMR®
33	Cameroon	Kribi FLNG	2018	2.4	Golar LNG, Keppel, Black & Veatch	Black & Veatch PRICO®
30	Australia	Wheatstone LNG T2	2018	4.45	Chevron, KUFPEC, Woodside, JOGMEC, Mitsubishi, Kyushu Electric, NYK, JERA	ConocoPhillips Optimized Cascade®
31	Russia	Yamal LNG T2	2018	5.5	Novatek, CNPC, TOTAL, Silk Road Fund	AP-C3MR™
14	Australia	Ichthys LNG T1	2018	4.45	INPEX, TOTAL, CPC, Tokyo Gas, Kansai Electric, Osaka Gas, JERA, Toho Gas	AP-C3MR/SplitMR®
31	Russia	Yamal LNG T3	2019	5.5	Novatek, CNPC, TOTAL, Silk Road Fund	AP-C3MR™

Sources: IHS Markit, Company Announcements
** 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.*

Appendix 2: Table of Liquefaction Plants Santioned or Under Construction

Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*
Indonesia	Senkang LNG T1	2019	0.5	EWC
United States	Elba Island LNG T1-6	2019	1.5	Kinder Morgan, EIG Global Energy Partners
Australia	Prelude FLNG	2019	3.6	Shell, INPEX, KOGAS, CPC
Australia	Ichthys LNG T2	2019	4.45	INPEX, TOTAL, CPC, Tokyo Gas, Kansai Electric, Osaka Gas, JERA, Toho Gas
Russia	Vysotsk LNG T1-2	2019	0.66	Novatek, Cryogas
Argentina	Tango FLNG	2019	0.5	YPF
United States	Cameron LNG T1	2019	4	Sempra, Mitsubishi/NYK JV, Mitsui, TOTAL
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, TOTAL
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
Russia	Yamal LNG T4	2019	0.94	Novatek, CNPC, TOTAL, Silk Road Fund
United States	Freeport LNG T2	2020	5.1	Freeport LNG, IFM Investors
United States	Cameron LNG T3	2020	4	Sempra, Mitsubishi/NYK JV, Mitsui, TOTAL
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
United States	Corpus Christi LNG T3	2021	4.5	Cheniere
Mozambique	Coral South FLNG	2022	3.4	Eni, ExxonMobil, CNPC, ENH, Galp Energia, KOGAS
Mauritania-Senegal	Greater Tortue FLNG 1**	2022	2.5	BP, Kosmos Energy, Petrosen, SMHPM
Canada	LNG Canada T1	2024	7	Shell, PETRONAS, CNPC, Mitsubishi, KOGAS
United States	Golden Pass LNG T1**	2024	5.2	ExxonMobil, Qatar Petroleum
United States	Golden Pass LNG T2**	2024	5.2	ExxonMobil, Qatar Petroleum
Canada	LNG Canada T2	2025	7	Shell, PETRONAS, CNPC, Mitsubishi, KOGAS
United States	Golden Pass LNG T3**	2025	5.2	ExxonMobil, Qatar Petroleum

Sources: IHS Markit, Company Announcements
** Companies are listed by size of ownership stake, starting with the largest stake.*
*** Greater Tortue FLNG 1 and Golden Pass LNG T1-3 had reached FID but not yet begun construction as of February 2019.*

Appendix 3: Table of LNG Receiving Terminals

Existing as of February 2019						
Reference Number	Market	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
1	Spain	Barcelona	1969	12.5	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	2.6	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
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	41.0	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	8.6	ENAGAS 100%	Onshore
23	Spain	Cartagena (Spain)	1989	8.6	ENAGAS 100%	Onshore
24	Japan	Oita	1990	5.1	Kyushu Electric 100%	Onshore
25	Japan	Yanai	1990	2.4	Chugoku Electric 100%	Onshore
26	Chinese Taipei	Yongan	1990	9.5	CPC 100%	Onshore
27	Japan	Yokkaichi Works	1991	0.7	Toho Gas 100%	Onshore
28	Turkey	Marmara Ereglisi	1994	7.6	Botas 100%	Onshore
29	Japan	Hatsukaichi	1996	0.7	Hiroshima 100%	Onshore
30	South Korea	Incheon	1996	53.6	KOGAS 100%	Onshore
31	Japan	Sodeshi	1996	1.6	Shizuoka Gas 65%; TonenGeneral 35%	Onshore
32	Japan	Kawagoe	1997	7.7	Chubu Electric 100%	Onshore
33	Japan	Sendai-Shin Minato Works	1998	0.5	Sendai City Gas 100%	Onshore
34	Japan	Ohgishima	1998	6.7	Tokyo Gas 100%	Onshore
35	US	Peñuelas	2000	1.2	Gas Natural Fenosa 47.5%; ENGIE 35%; Mitsui 15%; GE Capital 2.5%	Onshore
36	Greece	Revithoussa	2000	4.8	DEPA 100%	Onshore

Appendix 3: Table of LNG Receiving Terminals (continued)

Existing as of February 2019						
Reference Number	Market	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
37	Japan	Chita Midorihama Works	2001	8.3	Toho Gas 100%	Onshore
38	South Korea	Tongyeong	2002	26.6	KOGAS 100%	Onshore
39	Dominican Republic	Andrés	2003	1.9	AES 92%; Estrella-Linda 8%	Onshore
40	Spain	Bahia de Bizkaia Gas	2003	5.1	ENAGAS 50%; EVE 50%	Onshore
41	India	Dahej	2004	15.0	Petronet LNG 100%	Onshore
42	Portugal	Sines	2004	5.7	REN 100%	Onshore
43	UK	Grain	2005	14.8	National Grid Transco 100%	Onshore
44	South Korea	Gwangyang	2005	2.3	Posco 100%	Onshore
45	India	Hazira	2005	5.0	Shell 74%; TOTAL 26%	Onshore
46	Japan	Sakai	2005	6.4	Kansai Electric 70%; Cosmo Oil 12.5%; Iwatani 12.5%; Ube Industries 5%	Onshore
47	Turkey	Aliaga	2006	8.0	Egegaz 100%	Onshore
48	Mexico	Altamira	2006	5.4	Vopak 60%; ENAGAS 40%	Onshore
49	China	Guangdong	2006	6.8	Local companies 37%; CNOOC 33%; BP 30%	Onshore
50	Japan	Mizushima	2006	1.7	Chugoku Electric 50%; JX Nippon Oil & Energy 50%	Onshore
51	Spain	Saggas (Sagunto)	2006	6.4	ENAGAS 72.5%; Osaka Gas 20%; Oman Oil 7.5%	Onshore
52	Spain	Mugardos	2007	2.6	Grupo Tojeiro 50.36%; Gobierno de Galicia 24.64%; First State Regasificadora 15%; Sonatrach 10%	Onshore
53	Mexico	Costa Azul	2008	7.5	Sempra 100%	Onshore
54	US	Freeport LNG	2008	11.3	Michael S Smith Cos 57.5%; Global Infrastructure Partners 25%; Osaka Gas 10%; Dow Chemical 7.5%	Onshore
55	China	Fujian	2008	5.0	CNOOC 60%; Fujian Investment and Development Co 40%	Onshore
56	US	Northeast Gateway	2008	3.0	Excelerate Energy 100%	Floating
57	China	Shanghai Wuhaogou	2008	0.5	Shanghai Gas Group 100%	Onshore
58	US	Sabine Pass	2008	30.2	Cheniere Energy 100%	Onshore
60	Italy	Adriatic	2009	5.8	ExxonMobil 46.35%; Qatar Petroleum 46.35%; Edison 7.3%	Offshore
62	Canada	Canaport	2009	7.5	Repsol 75%; Irving Oil 25%	Onshore
63	UK	Dragon	2009	5.5	Shell 50%; PETRONAS 30%; 4Gas 20%	Onshore
64	Kuwait	Mina Al-Ahmadi	2009	5.8	Kuwait Petroleum Corporation 100%	Floating
65	Brazil	Pecém	2009	6.0	Petrobras 100%	Floating
66	Chile	Quintero	2009	4.0	ENAGAS 60.4%; ENAP 20%; Oman Oil 19.6%	Onshore
67	China	Shanghai	2009	3.0	Shenergy Group 55%; CNOOC 45%	Onshore
68	UK	South Hook	2009	15.6	Qatar Petroleum 67.5%; ExxonMobil 24.15%; TOTAL 8.35%	Onshore
69	Chinese Taipei	Taichung	2009	4.5	CPC 100%	Onshore
70	Japan	Sakaide	2010	0.7	Shikoku Electric 70%; Cosmo Gas 20%; Shikoku Gas 10%	Onshore
72	UAE	Dubai	2010	6.0	Dubai Supply Authority (Dusup) 100%	Floating
73	France	Fos Cavaou	2010	6.0	ENGIE 71.5%; TOTAL 28.5%	Onshore

Appendix 3: Table of LNG Receiving Terminals (continued)

Existing as of February 2019						
Reference Number	Market	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
74	China	Dalian	2011	6.0	CNPC 75%; Dalian Port 20%; Dalian Construction Investment Corp 5%	Onshore
75	Netherlands	GATE	2011	8.8	Gasunie 40%; Vopak 40%; Dong 5%; EconGas OMV 5%; EON 5%; RWE 5%	Onshore
78	Argentina	Escobar	2011	3.8	Enarsa 50%; YPF 50%	Floating
79	Thailand	Map Ta Phut	2011	11.5	PTT 100%	Onshore
80	China	Jiangsu	2011	6.5	PetroChina 55%; Pacific Oil and Gas 35%; Jiangsu Guoxin 10%	Onshore
81	Indonesia	Nusantara	2012	3.8	Pertamina 60%; PGN 40%	Floating
82	Japan	Ishikari	2012	1.4	Hokkaido Gas 100%	Onshore
83	Japan	Joetsu	2012	2.3	Chubu Electric 100%	Onshore
84	Mexico	Manzanillo	2012	3.8	Mitsui 37.5%; Samsung 37.5%; KOGAS 25%	Onshore
85	China	Dongguan	2012	1.5	Jovo Group 100%	Onshore
86	Japan	Yoshinoura	2012	0.5	Okinawa Electric 100%	Onshore
87	Israel	Hadera Gateway	2013	3.0	Israel Natural Gas Lines 100%	Floating
88	India	Ratnagiri	2013	2.0	GAIL 31.52%; NTPC 31.52%; Indian financial institutions 20.28%; MSEB Holding Co. 16.68%	Onshore
90	Singapore	Singapore	2013	11.0	Singapore Energy Market Authority 100%	Onshore
91	Malaysia	Sungai Udang	2013	3.8	PETRONAS 100%	Onshore
92	China	Zhejiang Ningbo	2013	3.0	CNOOC 51%; Zhejiang Energy Group Co Ltd 29%; Ningbo Power Development Co Ltd 20%	Onshore
93	China	Zhuhai	2013	3.5	CNOOC 30%; Guangdong Gas 25%; Guangdong Yuedian 25%; Local companies 20%	Onshore
94	Italy	FSRU Toscana	2013	2.7	EON 46.79%; IREN 46.79%; OLT Energy 3.73%; Golar 2.69%	Floating
95	China	Tangshan	2013	6.5	CNPC 51%; Beijing Enterprises Group 29%; Hebei Natural Gas 20%	Onshore
96	China	Tianjin (CNOOC) (FSRU)	2013	2.2	CNOOC 100%	Floating
97	Japan	Naoetsu	2013	2.1	INPEX 100%	Onshore
98	India	Kochi	2013	5.0	Petronet LNG 100%	Onshore
99	Brazil	Bahia	2014	3.8	Petrobras 100%	Floating
100	Chile	Mejillones	2014	1.5	ENGIE 63%; Codelco 37%	Onshore
101	Indonesia	Lampung	2014	1.8	PGN 100%	Floating
102	South Korea	Samcheok	2014	11.6	KOGAS 100%	Onshore
103	China	Hainan	2014	3.0	CNOOC 65%; Hainan Development Holding Co 35%	Onshore
104	Japan	Hibiki	2014	3.5	Saibu Gas 90%; Kyushu Electric 10%	Onshore
105	China	Shandong	2014	4.5	Sinopec 99%; Qingdao Port Group 1%	Onshore
106	Lithuania	Klaipeda	2014	3.0	Klaipedos Nafta 100%	Floating
107	China	Hainan Shennan	2014	0.6	CNPC 90%; Beijing Gas Blue Sky Holdings Ltd. 10%	Onshore
108	Indonesia	Arun LNG	2015	3.0	Pertamina 70%; Aceh Regional Government 30%	Onshore
109	Japan	Hachinohe	2015	1.6	JX Nippon Oil & Energy 100%	Onshore
110	Japan	Kushiro	2015	0.5	JX Nippon Oil & Energy 100%	Onshore

Appendix 3: Table of LNG Receiving Terminals (continued)

Existing as of February 2019						
Reference Number	Market	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
112	Pakistan	Elengy	2015	3.8	Engro Corp. 100%	Floating
113	Jordan	Aqaba	2015	3.8	Jordan Ministry of Energy and Mineral Resources (MEMR) 100%	Floating
115	Japan	Shin-Sendai	2015	1.7	Tohoku Electric 100%	Onshore
116	Japan	Hitachi	2016	1.8	Tokyo Gas 100%	Onshore
117	China	Beihai	2016	3.0	Sinopec 100%	Onshore
118	Poland	Swinoujscie	2016	3.6	GAZ-SYSTEM SA 100%	Onshore
120	Colombia	Cartagena (Colombia)	2016	3.0	Promigas 51%; Baru LNG 49%	Floating
121	France	Dunkirk	2017	9.5	EDF 65%; Fluxys 25%; TOTAL 10%	Onshore
122	South Korea	Boryeong	2017	3.0	GS Group 50%; SK Group 50%	Onshore
123	Turkey	Etki	2017	5.3	Etki Liman Isletmeleri Dolgalgaz Ithalat ve Ticaret 100%	Floating
124	Egypt	Sumed BW	2017	5.7	EGAS 100%	Floating
125	China	Qidong	2017	1.2	Xinjiang Guanghui Petroleum 100%	Onshore
126	China	Yuedong	2017	2.0	CNOOC 100%	Onshore
127	Malaysia	RGT2 (Pengerang)	2017	3.5	PETRONAS 65%; Dialog Group 25%; Johor Government 10%	Onshore
128	Pakistan	PGPC Port Qasim	2017	5.7	Pakistan LNG Terminals Limited 100%	Floating
129	China	Tianjin (Sinopec)	2018	3.0	Sinopec 98%; Tianjin Nangang Industrial Zone Developemnt Co., Ltd. 2%	Onshore
130	Japan	Soma	2018	1.3	JAPEX 100%	Onshore
131	Turkey	Dortyol	2018	4.1	Botas 100%	Floating
132	Bangladesh	Moheshkhali (Petrobangla)	2018	3.8	Petrobangla 100%	Floating
133	China	Shenzhen	2018	4.0	CNOOC 70%; Shenzhen Energy Group 30%	Onshore
134	Panama	Costa Norte	2018	1.5	AES 50%; Inversiones Bahia 50%	Onshore
135	China	Zhoushan	2018	3.0	ENN Energy 100%	Onshore

Source: IHS Markit, Company Announcements

Appendix 4: Table of LNG Receiving Terminals Under Construction

Under construction as of February 2019						
Reference Number	Market	Terminal or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
136	India	Ennore LNG	2019	5.0	Indian Oil Corporation 45%; Tamil Nadu Industrial Development Corporation 5%	Onshore
137	Jamaica	Old Harbour	2019	3.6	New Fortress Energy 100%	Floating
138	China	Shenzhen (Shenzhen Gas)	2019	0.8	Shenzhen Gas 100%	Onshore
139	Russia	Kaliningrad LNG	2019	3.5	Gazprom 100%	Floating
140	Bahrain	Bahrain LNG	2019	6.0	NOGA 30%; Teekay Corp 30%; Gulf Investment Corporation (GIC) 20%; Samsung 20%	Onshore
141	China	Tianjin (CNOOC) (onshore)	2019	2.2	CNOOC 46%; Tianjin Govt 40%; Tianjin Gas Group 9%; Tianjin Hengrongda Investment Company 5%	Onshore
142	Bangladesh	Moheshkhali (Summit Power)	2019	3.8	Summit Power 75%; Mitsubishi 25%	Floating
143	India	Jaigarh	2019	4.0	H-Energy 100%	Floating
144	India	Mundra	2019	5.0	Adani Group 50%; GSPC 50%	Onshore
145	US	San Juan	2019	0.5	New Fortress Energy 100%	Floating
146	China	Chaozhou	2019	1.0	Sinoenergy 55%; Huafeng Group 45%	Onshore
147	South Korea	Jeju Island	2019	1.0	KOGAS 100%	Onshore
148	Brazil	Sergipe	2020	3.6	Ebrasil 50%; Golar Power 50%	Floating
149	India	Jafrabad LNG Port	2020	5.0	Exmar 38%; Gujarat Government 26%; Swan Energy 26%; Tata Group 10%	Floating
150	Philippines	Pagbilao	2020	3.0	Energy World Corporation 100%	Onshore
151	China	Shenzhen (CNPC)	2020	3.0	CNPC 51%; CLP 24.5%; Shenzhen Gas 24.5%	Onshore
152	Ghana	GNPC Tema	2020	2.0	Ghana National Petroleum Company (GNPC) 50%; Helios Investment Partners 50%	Floating
153	China	Jiaxing	2020	1.0	Jiaxing Gas 34%; GCL 33%; Hangzhou Gas 33%	Onshore
154	Kuwait	Al Zour	2021	11.3	Kuwait Petroleum Corporation 100%	Onshore
155	Brazil	Port of Acu	2021	5.6	Prumo Logística 100%	Floating
156	India	Dharma Port	2021	5.0	Adani Group 51%; Indian Oil Corporation 29.4%; GAIL 19.6%	Onshore
157	El Salvador	Acajutla	2021	0.5	Energía del Pacífico	Floating
158	Indonesia	Java-1 (Cilamaya)	2021	2.4	Pertamina 26%; Other Companies 25%; Marubeni 20%; MOL 19%; Sojitz 10%	Floating
159	China	Binhai	2021	3.0	CNOOC 100%	Onshore
160	China	Wenzhou	2021	3.0	Zhejiang Energy Group Co Ltd 51%; Sinopec 41%; Wenzhou City 8%	Onshore
161	Croatia	Krk	2021	1.9	Plinacro 50%; HEP 50%	Floating
162	Thailand	Nong Fab	2022	7.5	PTT 100%	Onshore
163	China	Longkou (Sinopec)	2022	3.0	Sinopec 100%	Onshore
164	China	Zhangzhou	2022	3.0	CNOOC 60%; Fujian Investment and Development Co 40%	Onshore

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

Appendix 5: Table of LNG Receiving Terminals with Idle Capacity

Offshore terminals with no chartered FSRUs as of February 2019						
Reference Number	Market	Terminal or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
59	Argentina	Bahia Blanca	2008	3.8	YPF 50%; Stream JV 50%	Floating
71	Brazil	Guanabara Bay	2009	4.8	Petrobras 100%	Floating
111	Egypt	Ain Sokhna Hoegh	2015	4.2	EGAS 100%	Floating
114	Egypt	Ain Sokhna BW	2015	5.7	EGAS 100%	Floating
119	UAE	Abu Dhabi	2016	3.8	ADNOC 100%	Floating
Mothballed as of February 2019						
Reference Number	Market	Terminal or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
14	US	Lake Charles	1982	17.3	Energy Transfer Equity 100%	Onshore
61	US	Cameron LNG	2009	11.3	Sempra 50.2%; ENGIE 16.6%; Mitsubishi 16.6%; Mitsui 16.6%	Onshore
76	US	Golden Pass	2011	15.6	Qatar Petroleum 70%; ExxonMobil 17.6%; ConocoPhillips 12.4%	Onshore
77	US	Gulf LNG	2011	11.3	KM LNG Operating Partnership 50%; General Electric 40%; AES 10%	Onshore
89	Spain	El Musel	2013	5.1	ENAGAS 100%	Onshore

Source: IHS Markit, Company Announcements

Appendix 5: Table of Active Fleet, end-2018

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	DFDE	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

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
AL SHAMAL	Nakilat, Teekay	Samsung	Q-Flex	2008	213,536	SSD	9360893
AL SHEEHANIYA	Nakilat	Daewoo	Q-Flex	2009	205,963	SSD	9360831
AL THAKHIRA	K Line, Qatar Shpg.	Samsung	Conventional	2005	143,517	Steam	9298399
AL THUMAMA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Hyundai	Q-Flex	2008	216,235	SSD	9360843
AL UTOURIYA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Hyundai	Q-Flex	2008	211,879	SSD	9360867
AL WAJBAH	J4 Consortium	Mitsubishi	Conventional	1997	134,562	Steam	9085625
AL WAKRAH	J4 Consortium	Kawaski	Conventional	1998	134,624	Steam	9086746
AL ZUBARAH	J4 Consortium	Mitsui	Conventional	1996	135,510	Steam	9085649
ALTO ACRUX	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2008	147,798	Steam	9343106
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
ARMADA LNG MEDITERRANA	Bumi Armada Berhad	Mitsui	FSU	2016	127,209	Steam	8125868
ARWA SPIRIT	Teekay, Marubeni	Samsung	Conventional	2008	163,285	DFDE	9339260
ASEEM	MOL, NYK, K Line, SCI, Nakilat, Petronet	Samsung	Conventional	2009	154,948	DFDE	9377547
ASIA ENDEAVOUR	Chevron	Samsung	Conventional	2015	154,948	DFDE	9610779
ASIA ENERGY	Chevron	Samsung	Conventional	2014	154,948	DFDE	9606950
ASIA EXCELLENCE	Chevron	Samsung	Conventional	2015	154,948	DFDE	9610767
ASIA INTEGRITY	Chevron	Samsung	Conventional	2017	154,948	DFDE	9680188
ASIA VENTURE	Chevron	Samsung	Conventional	2017	154,948	TFDE	9680190
ASIA VISION	Chevron	Samsung	Conventional	2014	154,948	TFDE	9606948
ATLANTIC ENERGY	Sinokor Merchant Marine	Kockums	Conventional	1984	132,588	Steam	7702401
BAHRAIN SPIRIT	Teekay	Daewoo	FSU	2018	173,400	MEGI	9771080
BALTIC ENERGY	Sinokor Merchant Marine	Kawaski	Conventional	1983	125,929	Steam	8013950
BARCELONA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2009	173,400	TFDE	9401295
BEIDOU STAR	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	172,000	MEGI	9613159
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

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
BORIS DAVYDOV	Sovcomflot	Daewoo	Conventional	2018	172,000	TFDE	9768394
BORIS VILKITSKY	Sovcomflot	Daewoo	Conventional	2017	172,000	TFDE	9768368
BRITISH ACHIEVER	BP	Daewoo	Conventional	2018	174,000	MEGI	9766542
BRITISH CONTRIBUTOR	BP	Daewoo	Conventional	2018	174,000	MEGI	9766554
BRITISH DIAMOND	BP	Hyundai	Conventional	2008	151,883	DFDE	9333620
BRITISH EMERALD	BP	Hyundai	Conventional	2007	154,983	DFDE	9333591
BRITISH PARTNER	BP	Daewoo	Conventional	2018	174,000	MEGI	9766530
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
BU SAMRA	Nakilat	Samsung	Q-Max	2008	260,928	SSD	9388833
BW BOSTON	BW, TOTAL	Daewoo	Conventional	2003	138,059	Steam	9230062
BW EVERETT	BW	Daewoo	Conventional	2003	138,028	Steam	9243148
BW GDF SUEZ BRUSSELS	BW	Daewoo	Conventional	2009	162,514	DFDE	9368314
BW INTEGRITY	BW	Samsung	FSRU	2017	170,000	TFDE	9724946
BW LILAC	BW	Daewoo	Conventional	2018	174,300	MEGI	9758076
BW 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
BW SINGAPORE	BW	Samsung	FSRU	2015	170,000	TFDE	9684495
BW TULIP	BW	Daewoo	Conventional	2018	174,300	MEGI	9758064
CADIZ KNUTSEN	Knutsen OAS	IZAR	Conventional	2004	135,240	Steam	9246578
CAPE ANN	Hoegh, MOL, TLTC	Samsung	FSRU	2010	145,130	DFDE	9390680
CARIBBEAN ENERGY	Sinokor Merchant Marine	General Dynamics	Conventional	1980	126,530	Steam	7619575
CASTILLO DE CALDELAS	Elcano	Imabari	Conventional	2018	178,000	MEGI	9742819
CASTILLO DE MERIDA	Elcano	Imabari	Conventional	2018	178,000	MEGI	9742807
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	DFDE	9672820
CESI LIANYUNGANG	China Shipping Group	Hudong-Zhonghua	Conventional	2018	174,000	DFDE	9672818
CESI QINGDAO	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	DFDE	9672832
CESI TIANJIN	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	DFDE	9694749
CESI WENZHOU	China Shipping Group	Hudong-Zhonghua	Conventional	2018	174,000	TFDE	9694751
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

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
CHRISTOPHE DE MARGERIE	Sovcomflot	Daewoo	Conventional	2016	170,000	TFDE	9737187
CLEAN ENERGY	Dynagas	Hyundai	Conventional	2007	146,794	Steam	9323687
CLEAN HORIZON	Dynagas	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
DIAMOND GAS ORCHID	NYK	Mitsubishi	Conventional	2018	165,000	TFDE	9779226
DIAMOND GAS ROSE	NYK	Mitsubishi	Conventional	2018	165,000	TFDE	9779238
DISHA	MOL, NYK, K Line, SCI, Nakilat, Petronet	Daewoo	Conventional	2004	136,026	Steam	9250713
DOHA	J4 Consortium	Mitsubishi	Conventional	1999	135,203	Steam	9085637
DUHAIL	Commerz Real, Nakilat, PRONAV	Daewoo	Q-Flex	2008	210,100	SSD	9337975
DUKHAN	J4 Consortium	Mitsui	Conventional	2004	137,672	Steam	9265500
DWIPUTRA	P.T. Humpuss Trans	Mitsubishi	Conventional	1994	127,386	Steam	9043677
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 LIBERTY	MOL	Japan Marine	Conventional	2018	165,000	TFDE	9736092
ENERGY NAVIGATOR	Tokyo Gas, MOL	Kawaski	Conventional	2008	147,558	Steam	9355264
ENERGY PROGRESS	MOL	Kawaski	Conventional	2006	144,596	Steam	9274226
ENSHU MARU	K Line	Kawaski	Conventional	2018	164,700	Steam Reheat	9749609
ESSHU MARU	Mitsubishi, MOL, Chubu Electric	Mitsubishi	Conventional	2014	155,300	Steam	9666560
EXCALIBUR	Excelerate, Teekay	Daewoo	Conventional	2002	138,000	Steam	9230050
EXCELERATE	Exmar, Excelerate	Daewoo	FSRU	2006	135,313	Steam	9322255

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
EXCELLENCE	Excelerate Energy	Daewoo	FSRU	2005	138,124	Steam	9252539
EXCELSIOR	Excelerate Energy	Daewoo	FSRU	2005	138,000	Steam	9239616
EXEMPLAR	Excelerate Energy	Daewoo	FSRU	2010	151,072	Steam	9444649
EXPEDIENT	Excelerate Energy	Daewoo	FSRU	2010	147,994	Steam	9389643
EXPERIENCE	Excelerate Energy	Daewoo	FSRU	2014	173,660	TFDE	9638525
EXPLORER	Excelerate Energy	Daewoo	FSRU	2008	150,900	Steam	9361079
EXPRESS	Excelerate Energy	Daewoo	FSRU	2009	150,900	Steam	9361445
EXQUISITE	Excelerate Energy	Daewoo	FSRU	2009	151,035	Steam	9381134
FEDOR LITKE	Sovcomflot	Daewoo	Conventional	2017	172,000	TFDE	9768370
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
FORTUNE FSU	Dalian Inteh	Dunkerque Normandie	Conventional	1981	130,000	Steam	7428471
FRAIHA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	205,950	SSD	9360817
FSRU TOSCANA	OLT Offshore LNG Toscana	Hyundai	Converted FSRU	2004	137,500	Steam	9253284
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	TOTAL, NYK	Chantiers de l'Atlantique	Conventional	2007	151,383	DFDE	9320075
GASLOG CHELSEA	GasLog	Hanjin H.I.	Conventional	2010	153,600	TFDE	9390185
GASLOG GENEVA	GasLog	Samsung	Conventional	2016	174,000	TFDE	9707508
GASLOG GENOA	GasLog	Samsung	Conventional	2018	174,000	LP-2S	9744013
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 HONG KONG	GasLog	Hyundai	Conventional	2018	174,000	LP-2S	9748904
GASLOG HOUSTON	GasLog	Hyundai	Conventional	2018	174,000	LP-2S	9748899
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

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
GASLOG SYDNEY	GasLog	Samsung	Conventional	2013	154,948	TFDE	9626273
GCL	Hoegh	General Dynamics	Conventional	1979	126,000	Steam	7413232
GDF SUEZ POINT FORTIN	MOL, Sumitomo, LNG JAPAN	Imabari	Conventional	2010	154,982	Steam	9375721
GEMMATA	Shell	Mitsubishi	Conventional	2004	135,269	Steam	9253222
GEORGIY BRUSILOV	Dynagas	Daewoo	Conventional	2018	172,000	TFDE	9768382
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	TOTAL	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 ESKIMO	Golar LNG	Samsung	FSRU	2014	160,000	TFDE	9624940
GOLAR FREEZE	Golar LNG Partners	HDW	Converted FSRU	1977	126,000	Steam	7361922
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	Golar LNG	Samsung	Conventional	2015	160,000	TFDE	9637325
GOLAR IGLOO	Golar LNG Partners	Samsung	FSRU	2014	170,000	TFDE	9633991
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 NANOOK	Golar Power	Samsung	FSRU	2018	170,000	DFDE	9785500
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
GOLAR WINTER	Golar LNG Partners	Daewoo	Converted FSRU	2004	138,000	Steam	9256614
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

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
GULF ENERGY	General Dynamics	General Dynamics	Conventional	1978	126,750	Steam	7390143
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
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
HL SUR	Hanjin Shipping Co.	Hanjin H.I.	Conventional	2000	138,333	Steam	9176010
HOEGH ESPERANZA	Hoegh	Hyundai	FSRU	2018	170,000	DFDE	9780354
HOEGH GALLANT	Hoegh	Hyundai	FSRU	2014	170,000	DFDE	9653678
HOEGH GANNET	Hoegh	Hyundai	FSRU	2018	166,630	DFDE	9822451
HOEGH GIANT	Hoegh	Hyundai	FSRU	2017	170,000	DFDE	9762962
HOEGH GRACE	Hoegh	Hyundai	FSRU	2016	170,000	DFDE	9674907
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
IBRA LNG	OSC, MOL	Samsung	Conventional	2006	145,951	Steam	9326689
IBRI LNG	OSC, MOL, Mitsubishi	Mitsubishi	Conventional	2006	145,173	Steam	9317315
INDEPENDENCE	Hoegh	Hyundai	FSRU	2014	170,132	DFDE	9629536
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
KINISIS	Chandris Group	Daewoo	Conventional	2018	173,400	MEGI	9785158
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	DFDE	9629598
LIJMILIYA	Nakilat	Daewoo	Q-Max	2009	258,019	SSD	9388819
LNG ABALAMABIE	BGT Ltd.	Samsung	Conventional	2016	170,000	DFDE	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

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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 CAPRICORN	Nova Shipping & Logistics	General Dynamics	Conventional	1978	126,750	Steam	7390208
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	BGT 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 JUNO	MOL	Mitsubishi	Conventional	2018	180,000	TFDE	9774628
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	BGT 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
LNG PIONEER	MOL	Daewoo	Conventional	2005	138,000	Steam	9256602
LNG PORT-HARCOURT II	BGT Ltd.	Samsung	Conventional	2015	170,000	DFDE	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 SAKURA	NYK/Kepco	Kawasaki Sakaide	Conventional	2018	177,000	TFDE	9774135
LNG SATURN	MOL	Mitsubishi	Conventional	2016	153,000	Steam Reheat	9696149

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
LNG SCHNEEWEISSCHEN	Mitsui & Co	Daewoo	Conventional	2018	180,000	TFDE	9771913
LNG SOKOTO	BGT Ltd.	Hyundai	Conventional	2002	137,500	Steam	9216303
LNG TAURUS	Nova Shipping & Logistics	General Dynamics	Conventional	1979	126,750	Steam	7390167
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
LNG VIRGO	General Dynamics	General Dynamics	Conventional	1979	126,750	Steam	7390179
LOBITO	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	TFDE	9490961
LUCKY FSU	Dalian Inteh	Dunkerque Normandie	Conventional	1981	127,400	Steam	7428469
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
MAGDALA	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9770921
MAGELLAN SPIRIT	Teekay, Marubeni	Samsung	Conventional	2009	163,194	DFDE	9342487
MALANJE	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	DFDE	9490959
MARAN GAS ACHILLES	Maran Gas Maritime	Hyundai	Conventional	2015	174,000	DFDE	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	DFDE	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	DFDE	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	DFDE	9627497
MARAN GAS HECTOR	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	DFDE	9682605
MARAN GAS LINDOS	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	DFDE	9627502
MARAN GAS MYSTRAS	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	DFDE	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	DFDE	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 SPETSES	Maran G.M, Nakilat	Daewoo	Conventional	2018	173,400	MEGI	9767950
MARAN GAS TROY	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	TFDE	9658240
MARAN GAS ULYSSES	Maran Gas Maritime	Hyundai	Conventional	2017	174,000	TFDE	9709491
MARIA ENERGY	Tsakos	Hyundai	Conventional	2016	174,000	TFDE	9659725
MARIB SPIRIT	Teekay	Samsung	Conventional	2008	163,280	DFDE	9336749
MARSHAL VASILEVSKIY	Gazprom JSC	Hyundai	FSRU	2018	174,000	TFDE	9778313

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
MARVEL EAGLE	Mitsui & Co	Kawasaki Sakaide	Conventional	2018	155,000	TFDE	9759240
MARVEL FALCON	Mitsui & Co	Samsung	Conventional	2018	174,000	XDF	9760768
MARVEL HAWK	Mitsui & Co	Samsung	Conventional	2018	174,000	MEGI	9760770
MEDITERRANEAN ENERGY	Sinokor Merchant Marine	Mitsubishi	Conventional	1984	126,975	Steam	8125832
MEGARA	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9770945
MEKAINES	Nakilat	Samsung	Q-Max	2009	261,137	SSD	9397303
MERCHANT	Sinokor Merchant Marine	Samsung	Conventional	2003	138,517	Steam	9250191
MERIDIAN SPIRIT	Teekay, Marubeni	Samsung	Conventional	2010	163,285	DFDE	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	GasLog	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
MOL FSRU CHALLENGER	MOL	Daewoo	FSRU	2017	263,000	TFDE	9713105
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
MYRINA	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9770933
NEO ENERGY	Tsakos	Hyundai	Conventional	2007	146,838	Steam	9324277
NEPTUNE	Hoegh, MOL, TLTC	Samsung	FSRU	2009	145,130	DFDE	9385673

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
NIZWA LNG	OSC, MOL	Kawaski	Conventional	2005	145,469	Steam	9294264
NKOSSA II	AP Moller	Mitsubishi	Conventional	1992	78,488	Steam	9003859
NORTH ENERGY	Sinokor Merchant Marine	Mitsubishi	Conventional	1983	125,788	Steam	8014409
NORTHWEST SANDERLING	North West Shelf Venture	Mitsubishi	Conventional	1989	125,452	Steam	8608872
NORTHWEST SANDPIPER	North West Shelf Venture	Mitsui	Conventional	1993	125,042	Steam	8913150
NORTHWEST SEAEAGLE	North West Shelf Venture	Mitsubishi	Conventional	1992	125,541	Steam	8913174
NORTHWEST SHEARWATER	North West Shelf Venture	Kawaski	Conventional	1991	125,660	Steam	8608705
NORTHWEST SNIPE	North West Shelf Venture	Mitsui	Conventional	1990	127,747	Steam	8608884
NORTHWEST STORMPETREL	North West Shelf Venture	Mitsubishi	Conventional	1994	125,525	Steam	9045132
NORTHWEST SWAN	North West Shelf Venture	Daewoo	Conventional	2004	140,500	Steam	9250725
NUSANTARA REGAS SATU	Golar LNG Partners	Rosenberg Verft	Converted FSRU	1977	125,003	Steam	7382744
OAK SPIRIT	Teekay	Daewoo	Conventional	2016	173,400	MEGI	9681699
OB RIVER	Dynagas	Hyundai	Conventional	2007	146,791	Steam	9315692
OCEAN QUEST	GDF SUEZ	Newport News	Conventional	1979	126,540	Steam	7391214
OCEANIC BREEZE	K-Line, Inpex	Mitsubishi	Conventional	2018	153,000	Steam Reheat	9698111
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 BREEZE	K Line	Kawaski	Conventional	2018	182,000	TFDE	9698123
PACIFIC ENERGY	Sinokor Merchant Marine	Kockums	Conventional	1981	132,588	Steam	7708948
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 MIMOSA	NYK	Mitsubishi	Conventional	2018	155,300	Steam Reheat	9743875
PACIFIC NOTUS	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2003	137,006	Steam	9247962
PALU LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636735
PAN AMERICAS	Teekay	Hudong-Zhonghua	Conventional	2018	174,000	DFDE	9750232
PAN ASIA	Teekay	Hudong-Zhonghua	Conventional	2017	174,000	DFDE	9750220
PAN EUROPE	Teekay	Hudong-Zhonghua	Conventional	2018	174,000	DFDE	9750244
PAPUA	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	172,000	TFDE	9613135
PATRIS	Chandris Group	Daewoo	Conventional	2018	174,000	MEGI	9766889
PGN FSRU LAMPUNG	Hoegh	Hyundai	FSRU	2014	170,000	DFDE	9629524
POLAR SPIRIT	Teekay	I.H.I.	Conventional	1993	88,100	Steam	9001772
PORTOVYY	Gazprom	Daewoo	Conventional	2003	135,344	Steam	9246621
PRACHI	MOL, NYK, K Line, SCI, Nakilat, Petronet	Hyundai	Conventional	2016	173,000	TFDE	9723801
PROVALYS	TOTAL	Chantiers de l'Atlantique	Conventional	2006	151,383	DFDE	9306495
PSKOV	Sovcomflot	STX	Conventional	2014	170,200	DFDE	9630028
PUTERI DELIMA	MISC	Chantiers de l'Atlantique	Conventional	1995	127,797	Steam	9030814

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
PUTERI DELIMA SATU	MISC	Mitsui	Conventional	2002	134,849	Steam	9211872
PUTERI FIRUS	MISC	Chantiers de l'Atlantique	Conventional	1997	127,689	Steam	9030840
PUTERI FIRUS SATU	MISC	Mitsubishi	Conventional	2004	134,865	Steam	9248502
PUTERI INTAN	MISC	Chantiers de l'Atlantique	Conventional	1994	127,694	Steam	9030802
PUTERI INTAN SATU	MISC	Mitsubishi	Conventional	2002	134,770	Steam	9213416
PUTERI MUTIARA SATU	MISC	Mitsui	Conventional	2005	134,861	Steam	9261205
PUTERI NILAM	MISC	Chantiers de l'Atlantique	Conventional	1995	127,756	Steam	9030826
PUTERI NILAM SATU	MISC	Mitsubishi	Conventional	2003	134,833	Steam	9229647
PUTERI ZAMRUD	MISC	Chantiers de l'Atlantique	Conventional	1996	127,751	Steam	9030838
PUTERI ZAMRUD SATU	MISC	Mitsui	Conventional	2004	134,870	Steam	9245031
RAAHI	MOL, NYK, K Line, SCI, Nakilat, Petronet	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	DFDE	9477593
RIOJA KNUTSEN	Knutsen OAS	Hyundai	Conventional	2016	176,300	MEGI	9721736
RUDOLF SAMOYLOVICH	Teekay	Daewoo	Conventional	2018	172,000	TFDE	9750713
SALALAH LNG	OSC, MOL	Samsung	Conventional	2005	148,174	Steam	9300817
SCF MELAMPUS	Sovcomflot	STX	Conventional	2015	170,200	TFDE	9654878
SCF MITRE	Sovcomflot	STX	Conventional	2015	170,200	TFDE	9654880
SEAN SPIRIT	Teekay	Hyundai	Conventional	2018	174,000	MEGI	9781918
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 CAMAR	PETRONAS	Hyundai	Conventional	2018	150,200	Steam Reheat	9714305
SERI CAMELLIA	PETRONAS	Hyundai	Conventional	2016	150,200	Steam Reheat	9714276
SERI CEMARA	PETRONAS	Hyundai	Conventional	2018	150,200	Steam Reheat	9756389
SERI CEMPAKA	PETRONAS	Hyundai	Conventional	2017	150,200	MEGI	9714290
SERI CENDERAWASIH	PETRONAS	Hyundai	Conventional	2017	150,200	Steam Reheat	9714288

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
SESTAO KNUTSEN	Knutsen OAS	IZAR	Conventional	2007	135,357	Steam	9338797
SEVILLA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2010	173,400	DFDE	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
SINGAPORE ENERGY	Sinokor Merchant Marine	Samsung	Conventional	2003	136,135	Steam	9238040
SK AUDACE	SK Shipping, Marubeni	Samsung	Conventional	2017	180,000	XDF	9693161
SK RESOLUTE	SK Shipping, Marubeni	Samsung	Conventional	2018	180,000	XDF	9693173
SK SERENITY	SK Shipping	Samsung	Conventional	2018	174,000	DFDE	9761803
SK SPICA	SK Shipping	Samsung	Conventional	2018	174,000	MEGI	9761815
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
SOUTH ENERGY	Sinokor Merchant Marine	General Dynamics	Conventional	1980	126,750	Steam	7619587
SOUTHERN CROSS	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	169,295	Steam Reheat	9613147
SOYO	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	DFDE	9475208
SPIRIT OF HELA	MOL, Itochu	Hyundai	Conventional	2009	173,800	DFDE	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
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	DFDE	9349007

Appendix 5: Table of Active Fleet, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
TANGGUH HIRI	Teekay	Hyundai	Conventional	2008	151,885	DFDE	9333632
TANGGUH JAYA	K Line, PT Meratus	Samsung	Conventional	2008	154,948	DFDE	9349019
TANGGUH PALUNG	K Line, PT Meratus	Samsung	Conventional	2009	154,948	DFDE	9355379
TANGGUH SAGO	Teekay	Hyundai	Conventional	2009	151,872	DFDE	9361990
TANGGUH TOWUTI	NYK, PT Samudera, Sovcomflot	Daewoo	Conventional	2008	142,988	Steam	9325893
TEMBEK	Nakilat, OSC	Samsung	Q-Flex	2007	211,885	SSD	9337731
TENAGA EMPAT	MISC	CNIM	FSU	1981	130,000	Steam	7428433
TENAGA SATU	MISC	Dunkerque Chantiers	FSU	1982	130,000	Steam	7428457
TESSALA	HYPROC	Hyundai	Conventional	2016	171,800	TFDE	9761243
TORBEN SPIRIT	Teekay	Daewoo	Conventional	2017	173,400	MEGI	9721401
TRADER	Sinokor Merchant Marine	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	DFDE	9434266
VELIKIY NOVGOROD	Sovcomflot	STX	Conventional	2014	170,471	DFDE	9630004
VLADIMIR RUSANOV	MOL	Daewoo	Conventional	2018	172,000	TFDE	9750701
VLADIMIR VIZE	MOL	Daewoo	Conventional	2018	172,000	TFDE	9750658
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	DFDE	9682576
WOODSIDE DONALDSON	Teekay, Marubeni	Samsung	Conventional	2009	162,620	DFDE	9369899
WOODSIDE GOODE	Maran Gas Maritime	Daewoo	Conventional	2013	159,800	DFDE	9633161
WOODSIDE REES WITHERS	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9732369
WOODSIDE ROGERS	Maran Gas Maritime	Daewoo	Conventional	2013	159,800	DFDE	9627485
YARI LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636747
YENISEI RIVER	Dynagas	Hyundai	Conventional	2013	154,880	DFDE	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

Appendix 6: Table of LNG Vessel Orderbook, end-2018

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
ADRIANO KNUTSEN	Knutsen OAS	Hyundai	Conventional	2019	180,000	MEGI	9831220
BRITISH LISTENER	BP	Daewoo	Conventional	2019	174,000	MEGI	9766566
BRITISH MENTOR	BP	Daewoo	Conventional	2019	174,000	MEGI	9766578
BRITISH SPONSOR	BP	Daewoo	Conventional	2019	174,000	MEGI	9766580
BUSHU MARU	NYK	Mitsubishi	Conventional	2019	180,000	TFDE	9796793
BW COURAGE	BW	Daewoo	FSRU	2019	173,400	MEGI	9792591
BW IRIS	BW	Daewoo	Conventional	2019	173,400	MEGI	9792606
DAEWOO 2466	Maran Gas Maritime	Daewoo	Conventional	2019	170,000	MEGI	9810367
DAEWOO 2467	Maran Gas Maritime	Daewoo	Conventional	2019	170,000	MEGI	9810379
DAEWOO 2469	Maran Gas Maritime	Daewoo	Conventional	2020	169,540	MEGI	9844863
DAEWOO 2477	Maran Gas Maritime	Daewoo	FSRU	2020	173,400	DFDE	9820843
DAEWOO 2478	Maran Gas Maritime	Daewoo	Conventional	2020	169,540	MEGI	9845013
DAEWOO 2481	Minerva Marine	Daewoo	Conventional	2021	170,000		9854363
DAEWOO 2482	Minerva Marine	Daewoo	Conventional	2021	170,000		9854375
DAEWOO 2483	Alpha Tankers	Daewoo	Conventional	2020	170,000		9854612
DAEWOO 2484	Alpha Tankers	Daewoo	Conventional	2020	170,000		9854624
DAEWOO 2485	Alpha Tankers	Daewoo	Conventional	2021	173,400	MEGI	9859739
DAEWOO 2486	Maran Gas Maritime	Daewoo	Conventional	2020	169,540		9859753
DAEWOO 2487	Maran Gas Maritime	Daewoo	FSRU	2021	173,400		9859741
DAEWOO 2490	BW	Daewoo	Conventional	2019	170,799	MEGI	9850666
DAEWOO 2491	BW	Daewoo	Conventional	2020	170,799	MEGI	9850678
DAEWOO 2495	Maran Gas Maritime	Daewoo	Conventional	2021	173,400	MEGI	9874820
DAEWOO 2496	BW	Daewoo	Conventional	2021	174,000	MEGI	9873840
DAEWOO 2497	BW	Daewoo	Conventional	2021	174,000	MEGI	9873852
DAEWOO 2498	MOL	Daewoo	Conventional	2020	176,523	XDF	9877133
DAEWOO 2499	MOL	Daewoo	Conventional	2021	176,523	XDF	9877145
DIAMOND GAS SAKURA	NYK	Mitsubishi	Conventional	2019	165,000	STaGE	9810020
ENERGY GLORY	NYK	Japan Marine	Conventional	2019	165,000	TFDE	9752565
ENERGY INNOVATOR	MOL	Japan Marine	Conventional	2019	165,000	MEGI	9758832
FLEX AMBER	Flex LNG	Hyundai	Conventional	2020	170,520	XDF	9857377
FLEX AUROA	Flex LNG	Hyundai	Conventional	2020	170,520	XDF	9857365
FLEX CONSTELLATION	Frontline Management	Daewoo	Conventional	2019	170,234	MEGI	9825427
FLEX COURAGEOUS	Frontline Management	Daewoo	Conventional	2019	170,234	MEGI	9825439

Appendix 6: Table of LNG Vessel Orderbook, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
FLEX FREEDOM	Frontline Management	Daewoo	Conventional	2020	170,234	MEGI	9862308
FLEX RELIANCE	Flex LNG	Daewoo	Conventional	2020	170,234	MEGI	9851634
FLEX RESOLUTE	Flex LNG	Daewoo	Conventional	2020	170,234	MEGI	9851646
FLEX VIGILANT	Flex LNG	Hyundai	Conventional	2021	170,520	XDF	9862475
FLEX VOLUNTEER	Flex LNG	Hyundai	Conventional	2021	170,520	XDF	9862463
GASLOG GLADSTONE	GasLog	Samsung	Conventional	2019	174,000	XDF	9744025
GASLOG WARSAW	GasLog	Samsung	Conventional	2019	180,000	XDF	9816763
GASLOG WINDSOR	GasLog	Samsung	Conventional	2019	180,000	XDF	9819650
GEORGIY USHAKOV	Teekay	Daewoo	Conventional	2019	172,000	TFDE	9750749
HOEGH GALLEON	Hoegh	Samsung	FSRU	2019	170,000	DFDE	9820013
HUDONG-ZHONGHUA H1786A	Dynagas	Hudong-Zhonghua	FSRU	2021	174,000	DFDE	9861809
HUDONG-ZHONGHUA H1787A	Dynagas	Hudong-Zhonghua	FSRU	2021	174,000	DFDE	9861811
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 8007	Sovcomflot	Hyundai	Conventional	2020	174,000	XDF	9864746
HYUNDAI SAMHO 8008	Sovcomflot	Hyundai	Conventional	2021	174,000	XDF	9870525
HYUNDAI SAMHO 8029	NYK	Hyundai	Conventional	2020	174,000	XDF	9862487
HYUNDAI SAMHO 8030	NYK	Hyundai	Conventional	2021	174,000	XDF	9874454
HYUNDAI SAMHO 8031	NYK	Hyundai	Conventional	2021	174,000	XDF	9874466
HYUNDAI SAMHO 8039	Consolidated Marine Management	Hyundai	Conventional	2021	174,000	XDF	9872987
HYUNDAI SAMHO 8040	Consolidated Marine Management	Hyundai	Conventional	2021	174,000	XDF	9872999
HYUNDAI SAMHO S970	NYK	Hyundai	Conventional	2020	174,000	XDF	9852975
HYUNDAI ULSAN 3020	TMS Cardiff Gas	Hyundai	Conventional	2020	170,520	XDF	9845764
HYUNDAI ULSAN 3021	TMS Cardiff Gas	Hyundai	Conventional	2020	170,520	XDF	9845776
HYUNDAI ULSAN 3022	TMS Cardiff Gas	Hyundai	Conventional	2020	170,520	XDF	9845788
HYUNDAI ULSAN 3037	TMS Cardiff Gas	Hyundai	Conventional	2020	170,520	XDF	9864667
HYUNDAI ULSAN 3038	TMS Cardiff Gas	Hyundai	Conventional	2021	170,520	XDF	9869306
HYUNDAI ULSAN 3039	TMS Cardiff Gas	Hyundai	Conventional	2021	170,520	XDF	9872901

Appendix 6: Table of LNG Vessel Orderbook, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
HYUNDAI ULSAN 3095	Turkiye Petrolleri	Hyundai	FSRU	2020	170,000		9859820
HYUNDAI ULSAN 3096	Thenamaris	Hyundai	Conventional	2020	174,000		9861031
HYUNDAI ULSAN 3105	Capital Ship Management	Hyundai	Conventional	2020	174,000	XDF	9862891
HYUNDAI ULSAN 3106	Capital Ship Management	Hyundai	Conventional	2020	174,000	XDF	9862906
HYUNDAI ULSAN 3107	Capital Ship Management	Hyundai	Conventional	2021	174,000	XDF	9862918
HYUNDAI ULSAN 3108	Capital Ship Management	Hyundai	Conventional	2021	174,000	XDF	9862920
HYUNDAI ULSAN 3112	TMS Cardiff Gas	Hyundai	Conventional	2021	170,520	XDF	9872949
HYUNDAI ULSAN 3126	Thenamaris	Hyundai	Conventional	2021	174,000		9869265
IMABARI SAIJO 8215		Imabari	Conventional	2022	178,000	MEGI	9789037
IMABARI SAIJO 8216		Imabari	Conventional	2022	178,000	MEGI	9789049
IMABARI SAIJO 8217		Imabari	Conventional	2022	178,000	MEGI	9789051
JIANGNAN JOVO 1	Jovo Group	Jiangnan	Conventional	2021	79,800		9864837
JIANGNAN JOVO 2	Jovo Group	Jiangnan	Conventional	2021	79,800		9864849
JMU TSU 5073	MOL	Japan Marine	Conventional	2019	165,000	TFDE	9758844
KAWASAKI SAKAIDE 1729	Mitsui & Co	Kawasaki Sakaide	Conventional	2019	155,000	TFDE	9759252
KAWASAKI SAKAIDE 1735	NYK/Chubu Electric	Kawasaki Sakaide	Conventional	2019	177,000	DFDE	9791212
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 SYROS	Maran Gas Maritime	Daewoo	Conventional	2019	174,000	DFDE	9753026
MARVEL CRANE	NYK	Mitsubishi	Conventional	2019	177,000	TFDE	9770438
MARVEL KITE	Mitsui & Co	Samsung	Conventional	2019	174,000	MEGI	9760782
MARVEL SWAN	K Line	Imabari	Conventional	2020	178,000	MEGI	9778923
MITSUBISHI NAGASAKI 2322	Mitsui & Co	Mitsubishi	Conventional	2019	177,000	TFDE	9770440
NIKOLAY URVANTSEV	MOL	Daewoo	Conventional	2019	172,000	TFDE	9750660
NIKOLAY YEVGENOV	Teekay	Daewoo	Conventional	2019	172,000	TFDE	9750725
NOHSHU MARU	MOL	Mitsubishi	Conventional	2019	180,000	STaGE	9796781
PRISM AGILITY	SK Shipping	Hyundai	Conventional	2019	180,000	DFDE	9810549
PRISM BRILLIANCE	SK Shipping	Hyundai	Conventional	2019	180,000	DFDE	9810551
RIAS BAIXAS KNUTSEN	Knutsen OAS	Hyundai	Conventional	2019	180,000	MEGI	9825568
SAGA DAWN	Landmark Capital Ltd	Xiamen Shipbuilding Industry	Conventional	2019	45,000		9769855
SAMSUNG 2255	Jawa Satu Regas PT	Samsung	FSRU	2020	170,000	DFDE	9854935

Appendix 6: Table of LNG Vessel Orderbook, end-2018 (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
SAMSUNG 2262	GasLog	Samsung	Conventional	2020	152,880	XDF	9855812
SAMSUNG 2271	Cardiff Marine	Daewoo	Conventional	2020	152,880	XDF	9851787
SAMSUNG 2274	GasLog	Samsung	Conventional	2020	180,000	XDF	9853137
SAMSUNG 2275	TMS Cardiff Gas	Samsung	Conventional	2020	152,880	XDF	9862346
SAMSUNG 2276	TMS Cardiff Gas	Samsung	Conventional	2020	152,880	XDF	9863182
SAMSUNG 2297	Celsius Shipping	Samsung	Conventional	2020	180,000	XDF	9864784
SAMSUNG 2298	Celsius Shipping	Samsung	Conventional	2020	180,000	XDF	9864796
SAMSUNG 2300	GasLog	Samsung	Conventional	2020	174,000	XDF	9864916
SAMSUNG 2301	GasLog	Samsung	Conventional	2020	174,000	XDF	9864928
SAMSUNG 2302	NYK	Samsung	Conventional	2021	174,000	XDF	9870159
SAMSUNG 2304	Minerva Marine	Samsung	Conventional	2021	173,400		9869942
SAMSUNG 2306	NYK	Samsung	Conventional	2021	174,000	XDF	9874480
SAMSUNG 2307	NYK	Samsung	Conventional	2021	174,000	XDF	9874492
SAMSUNG 2308	TMS Cardiff Gas	Samsung	Conventional	2021	170,520	XDF	9875800
SAMSUNG 2311	GasLog	Samsung	Conventional	2021	176,400	XDF	9876660
SAMSUNG 2312	GasLog	Samsung	Conventional	2021	176,400	XDF	9876737
SCF LA PEROUSE	Sovcomflot	Hyundai	Conventional	2020	174,000	XDF	9849887
SHINSHU MARU	NYK	Kawasaki Sakaide	Conventional	2019	177,000	DFDE	9791200
TRAIANO KNUTSEN	Knutsen OAS	Hyundai	Conventional	2020	180,000	MEGI	9854765
TURQUOISE	Kolin / Kalyon	Hyundai	FSRU	2019	167,042	DFDE	9823883
VASANT	Triumph Offshore Pvt Ltd	Hyundai	FSRU	2019	180,000	DFDE	9837066
VLADIMIR VORONIN	Teekay	Daewoo	Conventional	2019	172,000	TFDE	9750737
YAKOV GAKKEL	MOL	Daewoo	Conventional	2019	172,000	TFDE	9750672
YAMAL SPIRIT	Teekay	Hyundai	Conventional	2019	174,000	MEGI	9781920

NOTES

NOTES

NOTES


good new energy
What our energy is. What we are.
We are **good** because for almost 50 years we've been making people's lives better by operating natural gas infrastructure safely and efficiently.
We are **new** because we innovate and develop our services and solutions for an increasingly competitive energy.
We are **energy** because we work with determination and enthusiasm with one of the cleanest energies for a sustainable future.
World leader in its sector on the Dow Jones Sustainability Index in 2018.

IGU
INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ

International Gas Union (IGU)
Att: Naturgy,
Plaça del Gas, 1,
Building A 2nd floor,
08003 Barcelona,
Spain

Telephone: + 34 93 412 97 89
Fax: + 34 93 402 54 26
E-mail: secretariat@igu-gasnatural.com