INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ

2020 WORLD LNG REPORT

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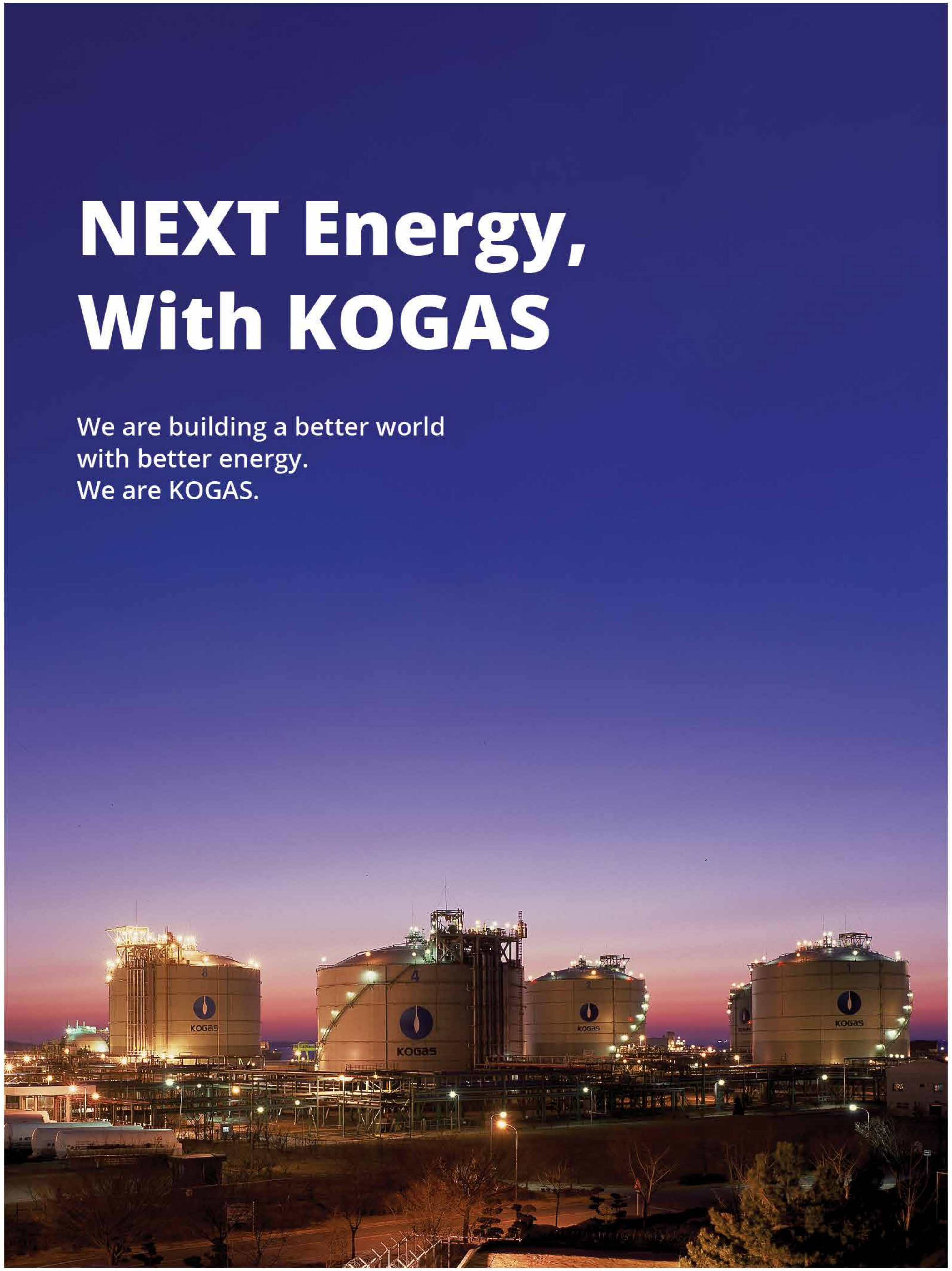
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MESSAGE FROM THE PRESIDENT OF THE INTERNATIONAL GAS UNION

Dear colleagues,

I write this message with a heavy heart at a time when the world is struggling to manage the growing global impact of the COVID-19 virus. These are difficult times and I hope we emerge stronger and more united. Access to energy remains a critical enabler to keeping people safe, connected and informed in such times and our industry plays a critical role in making sure that the lights are on, homes are heated, hospitals and industry keep running and essential goods are transported without disruption.

I present to you the *2020 IGU World LNG Report,* a comprehensive overview of physical and market developments in the global LNG industry in 2019.

Gas continues to play a vital role towards an economically and environmentally sustainable energy future. LNG in 2019 continued to play a key role in improving air quality in markets such as China. It produces less than 10% of the particulates[1] and 50% less GHG than coal when used in power[2], 21% less than fuel oil in transport[3] and above 95% efficiency[4] when used to heat homes. The industry continues to improve measurement and reduction of emissions across the full LNG value chain.

Global LNG trade increased to 354.7 MT, an increase of 40.9 MT since 2018 and the sixth year of consecutive growth in LNG trade. This was on the back of increased exports from the USA, Russia and Australia as well as Algeria and Egypt. Asia Pacific and Asia again imported the most volumes in 2018, together accounting for almost 70% of global LNG imports. However, the largest change in imports was observed in Europe, where the UK, France, Spain, the Netherlands, Italy and Belgium together imported 32 MT more than in 2018.

Furthermore, 70.8 MTPA of liquefaction capacity was sanctioned, and 41.8 MTPA in capacity was brought on-stream in 2019, mostly from Russia, Australia and the US. A huge wave of liquefaction capacity is currently still in pre-Final Investment Decision stages, totalling 907.4 MTPA with most of this capacity in the US and Canada, and a significant proportion in Africa and the Middle East (93.3 MTPA each).

The LNG shipping industry kept pace with this growth, adding 42 new vessels to a total of 541 active vessels by the end of 2019. The active fleet includes 34 FSRUs and 4 FSUs, demonstrating the continued interest in flexible solutions to enable markets to start importing LNG or increase their LNG imports as energy demand grows.

Regasification capacity continued to absorb the increase in supply and meet demand growth, adding 23.4 MTPA in 2019, reaching 821 MTPA by February 2020. Six new terminals began importing cargoes in 2019, and three expansion projects were completed. Asia Pacific took the lion's share of regas capacity additions with a total of 14.2 MTPA, while India added 7.5 MTPA. A total of 37 markets are now equipped to import LNG. A further 120.4 MTPA of regas capacity is currently under construction (as of Feb 2020), of which 12 are FSRUs, and of which 47.1 MTPA is expected to be onstream by end 2020, potentially adding 3 new importing markets: Bahrain, Ghana and the Philippines. 2019 also showed significant growth specifically for floating regas terminals with FSRUs being added in Jamaica, Turkey and Bangladesh

Interest in LNG as a marine fuel increased with the IMO 2020 regulations coming into force at the start of 2020, which will help reduce emissions, improve efficiency and trigger cost benefits. While the industry has invested in infrastructure ahead of demand, continued investment in the coming years will aid the adoption of LNG as a marine fuel. Gas continued to deliver security of electricity supply critical to the growing share of renewable energies. This is not just supporting renewables on the days wind does not blow or the sun does not shine, but also supports hydro-electric generation during extended dry seasons in, for example, Brazil and Colombia. Argentina demonstrated how flexible the LNG supply chain can be to respond to changing gas monetisation strategies – from signing of the charter agreement for the FLNG unit to export of the first LNG cargo took a mere 12 months.

Almost a billion people today have no access to electricity[5] and nearly three billion have to cook with fuels that produce toxic fumes in their homes[6]. Indoor air quality still represents a large part of the premature deaths attributable to air pollution (3.8 million deaths in 2016[7]) – proof of the urgent need to tackle this issue. As the cleanest-burning fossil fuel, natural gas has a key role in providing reliable and cleaner energy to all. Even in the most developed markets, affordability and reliability of clean energy is a key issue and switching to natural gas offers an enormous opportunity. The IGU will continue to demonstrate the vital environmental and economic role of gas in the sustainable energy future and encourage collaboration between industry and communities towards achieving this future.

Yours faithfully,

Joe M. Kang
President of the International Gas Union

[1] US DoE National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants Volume 1a, Rev 3, 2015 (https://www.netl.doe.gov/projects/files/CostandPerformanceBaselineforFossilEnergyPlantsVolume1aBitCoalPCandNaturalGastoElectRev3_070615.pdf)
[2] IEA, The Role of Gas in Today's Energy Transitions (https://www.iea.org/reports/the-role-of-gas-in-todays-energy-transitions)
[3] Thinkstep, Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel (https://www.thinkstep.com/content/life-cycle-ghg-emission-study-use-lng-marine-fuel-0)
[4] IEA, Tracking Buildings (https://www.iea.org/reports/tracking-buildings/heat-pumps)
[5] IEA, Population without access to electricity falls below 1 billion (https://www.iea.org/commentaries/population-without-access-to-electricity-falls-below-1-billion)
[6] WHO, Household air pollution and health (https://www.who.int/news-room/fact-sheets/detail/household-air-pollution-and-health)
[7] WHO, Household air pollution and health (https://www.who.int/news-room/fact-sheets/detail/household-air-pollution-and-health)

1.0 State of the LNG Industry

Samcheok LNG Terminal - Courtesy of KOGAS

LNG Trade[1]

40.93 MT
Increase in Global LNG Trade, Since 2018

Global LNG trade increased further in 2019, reaching 354.73 MT, an increase of 40.93 MT since the end of 2018. This constitutes an increase of 13%, a sixth year of consecutive growth.

Most of the additional exported volumes in 2019 were from existing exporting markets: the US (+13.1 MT), Australia (+8.7 MT) and Russia (+11 MT). Qatar managed to maintain its position as the largest exporter in the world (77.8 MT), closely followed by Australia (75.4 MT). The USA (33.8 MT) overtook Malaysia (26.2 MT) as the third largest exporter, and added record export volumes. Russia is now the fourth largest exporter of LNG (29.3 MT). Asia Pacific continued it's growth trajectory as the largest export region (131.7 MT).

Only three markets saw a drop in export levels versus 2018: Indonesia saw the largest drop in export (-2.7 MT), followed by Equatorial Guinea (-0.65 MT) and Norway (-0.45 MT). No new importers were added to the list in 2019. However, most recent new importers increased imports further in 2019, such as Bangladesh, Pakistan, Poland and Panama. The largest increases in imports were seen in Europe, with the UK, France, Spain, the Netherlands, Italy and Belgium accounting for most of the additional imports (+32 MT). Asian and Asian Pacific markets that contributed to global trade were China, India and Malaysia. The largest importing regions, consistent with 2018, were Asia Pacific (131.7 MT) and Asia (114.5 MT).

Liquefaction Plants

42.5 MTPA
Global Liquefaction Capacity Added, 2019

Global liquefaction capacity continued to grow significantly in 2019, totaling 42.5 MTPA in capacity additions. Ichthys LNG T1-2 (8.9 MTPA) and Yamal LNG T3 (5.5 MTPA) were commissioned in late 2018 and began commercial deliveries in 2019. Corpus Christi LNG T1-2 (9 MTPA), Cameron LNG T1 (4.0 MTPA), Freeport LNG T1 (5.1 MTPA), Sabine Pass T5 (4.5 MTPA) and Elba Island T1-3 (0.75 MTPA) commenced commercial operations in 2019, contributing to more than half of the capacity additions. Prelude FLNG (3.6 MTPA) and Tango FLNG (0.5 MTPA) achieved commercial exports in June 2019, becoming the third and fourth operational FLNG developments in the world after Cameroon FLNG (2.4 MTPA) and Petronas FLNG Satu (1.2 MTPA). As of December 2019, 123.3 MTPA of liquefaction capacity was under construction or sanctioned for development. 24.35 MTPA out of the 123.3 MTPA capacity is expected to come online in 2020. In addition, 2019 also saw a record in sanctioned liquefaction capacity, totaling 70.8 MTPA. The FIDs were largely driven by the expectation of growing LNG demand globally, creating the need for additional liquefaction capacity.

[1] LNG trade data for 2019 in this report has been supplied by GIIGNL, and is compared against GIIGNL data from 2018, from the GIIGNL Annual Report 2019 (https://giignl.org/publications/giignl-2019-annual-report). Other data in this report is supplied by Rystad Energy.

Proposed New Liquefaction Plants

907.4 MTPA
Proposed Liquefaction Capacity, 2020

Currently, 907.4 MTPA of liquefaction capacity is in pre-FID stage, with the majority of the proposed capacity coming from the United States and Canada. Africa has 93.3 MTPA of liquefaction capacity proposed and could emerge as a key LNG production region if those projects materialise. The Qatar LNG expansion plan is progressing towards FID and those capacity additions could re-position Qatar as the market with the largest liquefaction capacity globally.

The record volume of sanctioned liquefaction projects is underpinned by the expectation of growing LNG demand globally, creating the need for additional liquefaction capacity. This will also lead to competition to secure EPC capacity, as project developers aim to enter the market by the mid-2020s in order to capture growing demand.

Shipping

541 Vessels
LNG Fleet, End-2019

The global LNG fleet consisted of 541 active vessels at the end of 2019, including 34 Floating Storage Regasification Units (FSRUs) and four Floating Storage Units (FSUs). Overall, the global LNG fleet grew by 8.4% year-on-year (YoY) in 2019, with a total addition of 42 new vessels, out of which three were FSRUs. By comparison, annual growth of LNG trade in 2019 stands at 13%[2], showing a good balance between growth in the LNG shipping market and LNG trade. Charter costs in 2019 began strong at approximately $70,000 per day for steam turbine vessels and $100,000 per day for TFDE/DFDE. Rates decreased to level off at approximately $30,000 for steam turbine vessels and about $40,000 for TFDE/DFDE vessels, varying as expected with summer months impacting LNG shipment volumes. Sanctions on COSCO followed by a European storage buildup and sustained increases in US production caused an acute increase in charter prices, peaking in late October 2019 before declining towards the end of the year.

LNG Receiving Terminals

826 MTPA
Global Nominal Regasification Capacity, February 2020

Global regasification capacity grew during the past year, reaching a total of 821 MTPA as of February 2020. With a total regasification capacity expansion of 23.4 MTPA, 2019 marked the second consecutive year in which regasification capacity additions were outpaced by increases in liquefaction capacity. Six new terminals began importing LNG cargoes in 2019 and expansion projects at three existing terminals were successfully completed. A significant share of regasification capacity additions occurred in the Asia and Asia Pacific regions, contributing a total of 14.2 MTPA in receiving capabilities, reaffirming the regions' status as a source of demand growth. In particular, India added the most regasification capacity through terminal construction and expansion, amounting to 7.5 MTPA of commissioned capacity. As of February 2020, 37 markets are equipped with LNG receiving capabilities. Accompanying the rise of global LNG trade, regasification capacity expansion is anticipated to follow in established regions as well as a number of new markets, both of which are experiencing surges in gas demand. As of February 2020, 120.4 MTPA of new regasification capacity was under construction, including 14 new onshore terminals, 12 floating storage and regasification units (FSRUs), and seven expansion projects at existing receiving terminals. By year-end 2020, 47.1 MTPA of regasification capacity is set to come online and could include new importers such as Ghana.

Floating Regasification

101.2 MTPA
Regasification Capacity, February 2020

Regasification capacity at operational offshore terminals experienced an increase of 13.0 MTPA in 2019 through the construction of three new-built floating terminals at ports in Brazil (Sergipe), Jamaica (Old Harbour) and Bangladesh (Moheshkhali (Summit)) as well as the chartering of a replacement FSRU with larger receiving capabilities in an existing market – Turkey (Etki). Kuwait's Mina al-Ahmadi terminal has signed a new two-year charter contract beginning March 2020 with its existing FSRU – Golar Igloo, after its first charter contract concluded at the end of 2019. By early 2020, offshore regasification capacity at 24 operational terminals rose to reach 101.2 MTPA. As of February 2020, 12 offshore terminals, adding up to 36.6 MTPA of regasification capacity, were under construction. Eight terminals have announced plans to come online by end-2020, including new importers such as Ghana. Beyond 2020, other new importers, such as El Salvador, Croatia and Cyprus, are anticipated to add their first regasification terminals through offshore facilities. Mature markets are also expanding floating regasification capabilities, a prime example being India, which is anticipated to commission its first FSRU-based terminal in early 2020, equipping India with both onshore and floating regasification terminals. As of February 2020, there were about 10 FSRUs (including conversions) on the order book of shipbuilding yards. The FSRU market for offshore terminals experienced a surplus in 2019, with a number of vessels temporarily utilised as conventional LNG carriers while others were open for charter.

[2] GIIGNL

2 LNG Trade

Global LNG trade increased to **354.7 MT** in 2019, an increase of **40.9 MT** or 13% vs. 2018. This is the sixth year of consecutive growth in global LNG trade.

Australia is the second largest exporter with a total of **75.4 MT**

2nd

Qatar managed to maintain its position as the largest exporter in the world, exporting **77.8 MT**

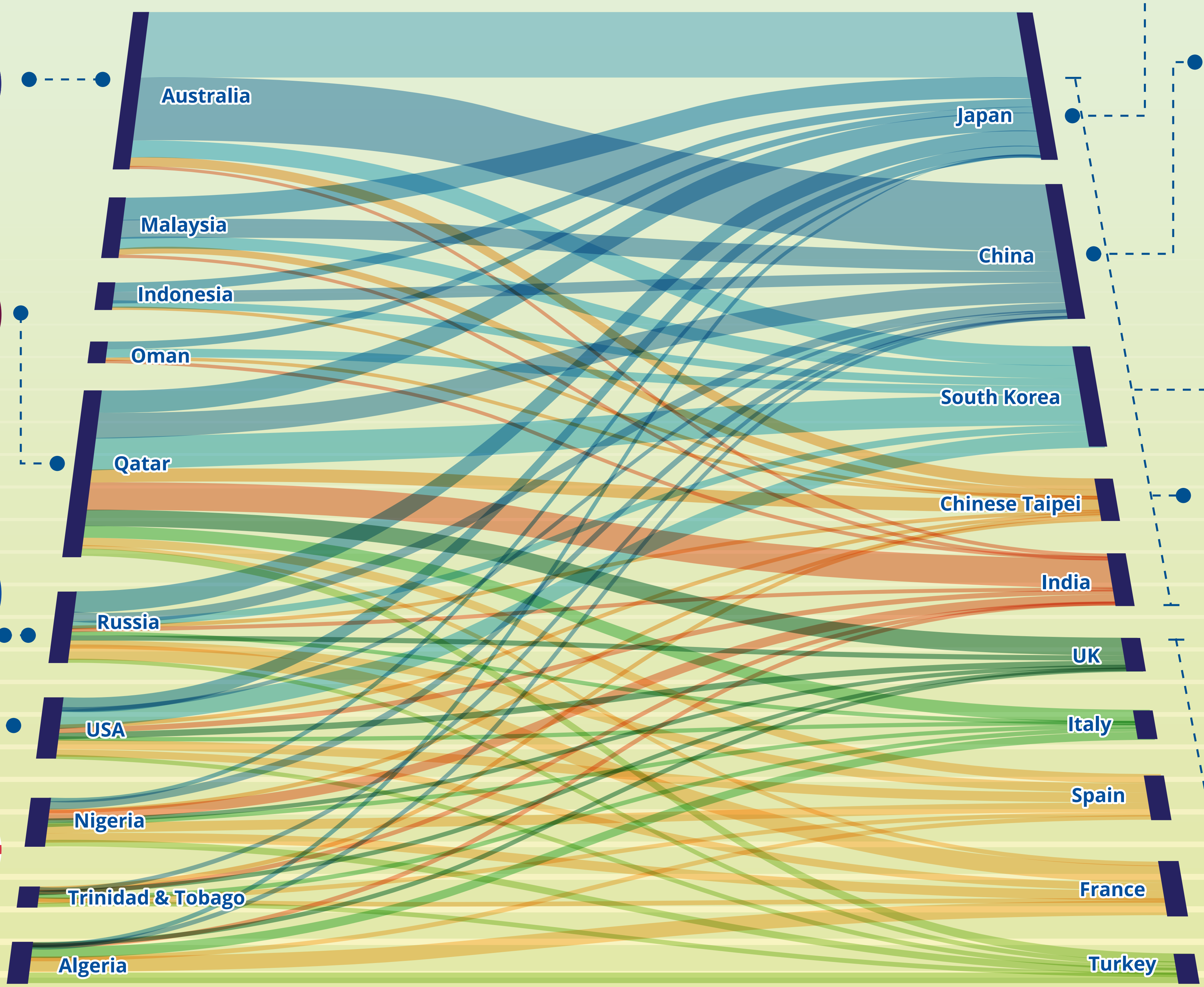
1st

Russia is now the fourth largest exporter of LNG, with **29.3 MT** of export in 2019

4th

The USA overtook Malaysia as the third largest exporter, and added a record of **+13.1 MT**

3rd



Japan imported **76.9 MT** (-5.6 MT vs. 2018)

China imported **61.7 MT** (+7.7 MT vs. 2018)

The largest global LNG trade flow route continues to be intra-Asia Pacific trade **77.3 MT**

The largest importing regions, consistent with 2018, were

- Asia Pacific **131.7 MT**
- Asia **114.5 MT**

European imports surged on the back of low prices, almost doubling to **85.9 MT**

*The diagram only represents trade flows between the top 10 exporters and top 10 importers.

2.0 LNG Trade

Global LNG trade increased further in 2019, reaching 354.7 MT, an increase of 40.9 MT since the end of 2018. This constitutes an increase of approximately 13%, a sixth year of consecutive growth.

Shell LNG Station - Courtesy of Shell

2.1 OVERVIEW

Global LNG trade increased further in 2019, reaching 354.7 MT, an increase of 40.9 MT since the end of 2018. This constitutes an increase of approximately 13%, a sixth year of consecutive growth.

Most of the additional exported volumes in 2019 were from existing exporting markets: the US (+13.1 MT), Australia (+8.7 MT) and Russia (+11 MT). Qatar managed to maintain its position as the largest exporter in the world (77.8 MT), closely followed by Australia (75.4 MT). The USA (33.8 MT) overtook Malaysia (26.2 MT) as the third largest exporter, and added record export volumes. Russia is now the fourth largest exporter of LNG (29.3 MT) and Malaysia the fifth largest exporter. Asia Pacific continued its growth trajectory as the largest export region (131.7 MT).

Only three markets saw a drop in export levels versus 2018: Indonesia saw the largest drop in export (-2.7 MT), followed by Equatorial Guinea (-0.7 MT) and Norway (-0.5 MT). Gibraltar was the only new importing market in 2019, but has been excluded from this report as the capacity is below 0.5 MTPA. Most recent new importers increased imports further in 2019, such as Bangladesh, Pakistan, Poland and Panama. The largest increases in imports were seen in Europe, with the UK, France, Spain, the Netherlands, Italy and Belgium accounting for most of the additional imports (+32 MT) in this order. The largest importing regions, consistent with 2018, were Asia Pacific (131.7 MT) and Asia (114.5 MT). Key Asian and Asian Pacific markets that contributed to these regions' high imports continue to be Japan (76.9 MT), China (61.7 MT), India (24 MT) and Chinese Taipei (16.7 MT).

Global LNG Trade	LNG Exporters & Importers	LNG Re-Exports
+40.9 MT Growth of global LNG trade	No new LNG importers in 2019[1]	-2.2 MT Re-exported volumes decreased by 59% YOY in 2019
Global LNG trade reached an all-time high of 354.7 MT in 2019, setting a new annual record. China provided 7.7 MT in new import demand, and Europe increased imports by 37 MT. Contractions were largest in Japan (-5.6 MT), South Korea (-3.8 MT) and Egypt (-1.9 MT).	Bangladesh, Brazil, China, India, and Jamaica increased imports through new-built terminals. While most liquefaction capacity was added in markets already exporting LNG, a floating liquefaction project came online in Argentina, raising the number of exporters to 20.	Re-export activity dropped in 2019 to 1.6 MT (3.8 MT in 2018). Re-exports received dropped in all markets. Asia received the largest volume of re-exports (0.9 MT), while Europe re-exported the highest volumes (0.9 MT).

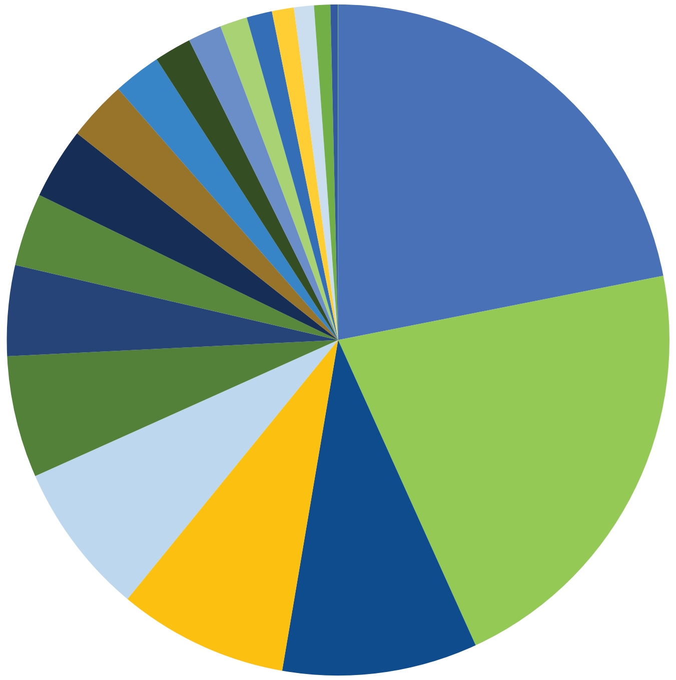
Kogas Jeju LNG Terminal – Courtesy of Kogas

[1] This report excludes those with only small-scale (<0.5 MTPA) regasification capacity but includes markets with large regasification capacity that only consume domestically-produced cargoes, such as Indonesia.

2.2 LNG EXPORTS BY MARKET

Most of the liquefaction capacity added in 2019 was from existing exporting markets: the US, Australia and Russia. Argentina's 0.5 MTPA Tango FLNG came on-stream and that made Argentina the 20th global exporter of LNG in the world.

Figure 2.1: 2019 LNG Exports and Market Share by Market (in MT)



Source : GIIGNL

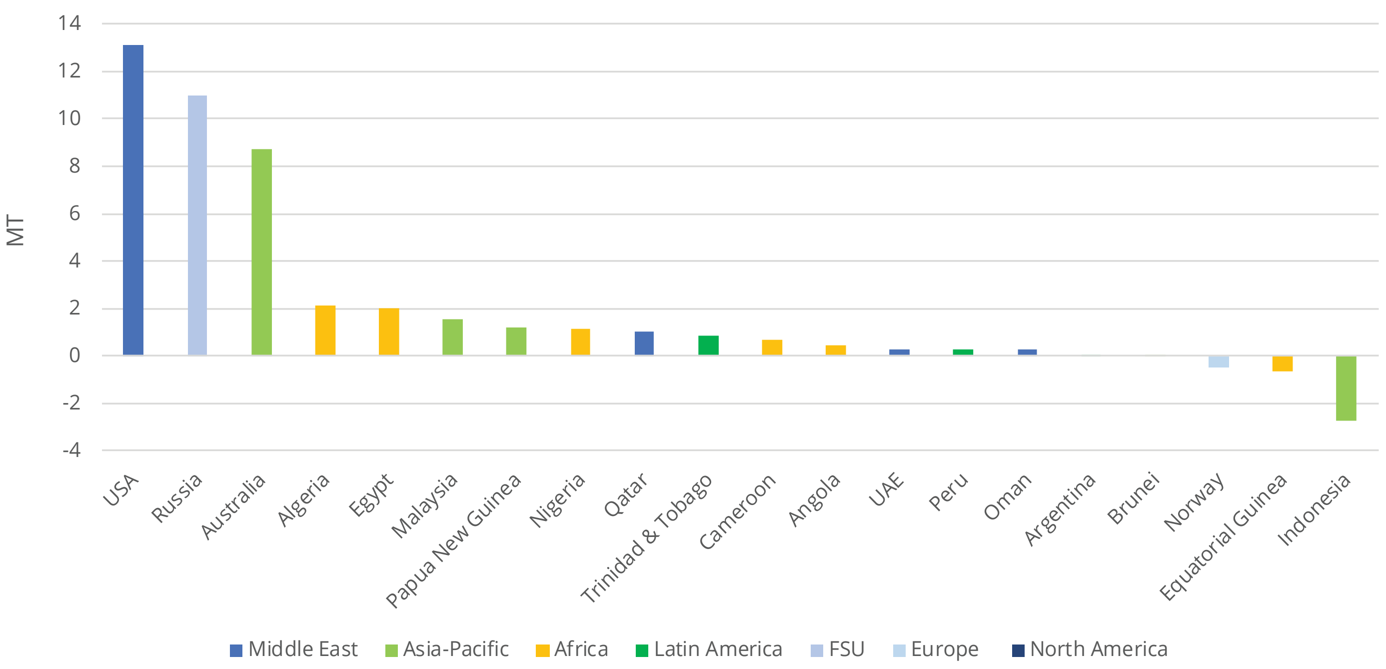
Qatar managed to maintain its position as the largest exporter in the world, exporting 77.8 MT in 2019, closely followed by Australia who exported a total of 75.4 MT, an increase of 13% year-on-year, driven by the start-ups of Ichthys LNG T1-2 (8.9 MTPA) and Prelude FLNG (3.6 MTPA). The USA overtook Malaysia as the third largest exporter, and added a record of 13.1 MT, an increase of 63% as Corpus Christi LNG T1-2 (9 MTPA), Cameron LNG T1 (4.0 MTPA), Freeport LNG T1 (5.1 MTPA), Sabine Pass T5 (4.5 MTPA) and Elba Island T1-3 (0.75 MTPA) started up. Russia is now the fourth largest exporter of LNG, with 29.3 MT of export in 2019 as Yamal LNG T3 (5.5 MTPA) and Vysotsk LNG (0.66 MTPA) were commissioned and started exporting cargoes, an increase of 60% compared to 2018.

Another large shift in export volumes was observed in Algeria (+2.1 MT), which managed to recover some of the drop in export observed in 2018 (-2.2 MT) due to the drop in gas and LNG prices, making LNG more competitive versus pipeline options into Europe. Egypt also increased LNG exports significantly, exporting an additional 2 MT compared to 2018, driven by Idku LNG reaching full export capacity at end 2019. Lastly, Argentina commissioned the Tango floating LNG project in June 2019, subsequently exporting a first cargo in November, thus adding Argentina to the list of global LNG exporters.

Only three markets saw a drop in export levels versus 2018. Indonesia saw the largest drop in export (-2.7 MT) in 2019, mainly driven by declining gas resources feeding into Bontang LNG and turndowns in the lower price environment. Equatorial Guinea has also started to see gas supply declining, triggering a drop in export of 0.7 MT. Lastly, Norway saw a decrease in export (-0.5 MT) due to accelerated maintenance in the lower price environment.

Asia Pacific continued it's growth trajectory as the largest export region, exporting a total of 131.7 MT in 2019, an increase of 7%, driven by the aforementioned increases in production from Australia as well as from Papua New Guinea (+1.2 MT). The largest regional increases came from North America (63%, driven by the USA) and the FSU (Russia, 60%). Africa also added significant exports (+5.7 MT) through increases from Algeria, Egypt and Cameroon as they ramped up production and exports in 2019. The Middle East only increased exports by 2% with small increases from Qatar, the UAE and Oman.

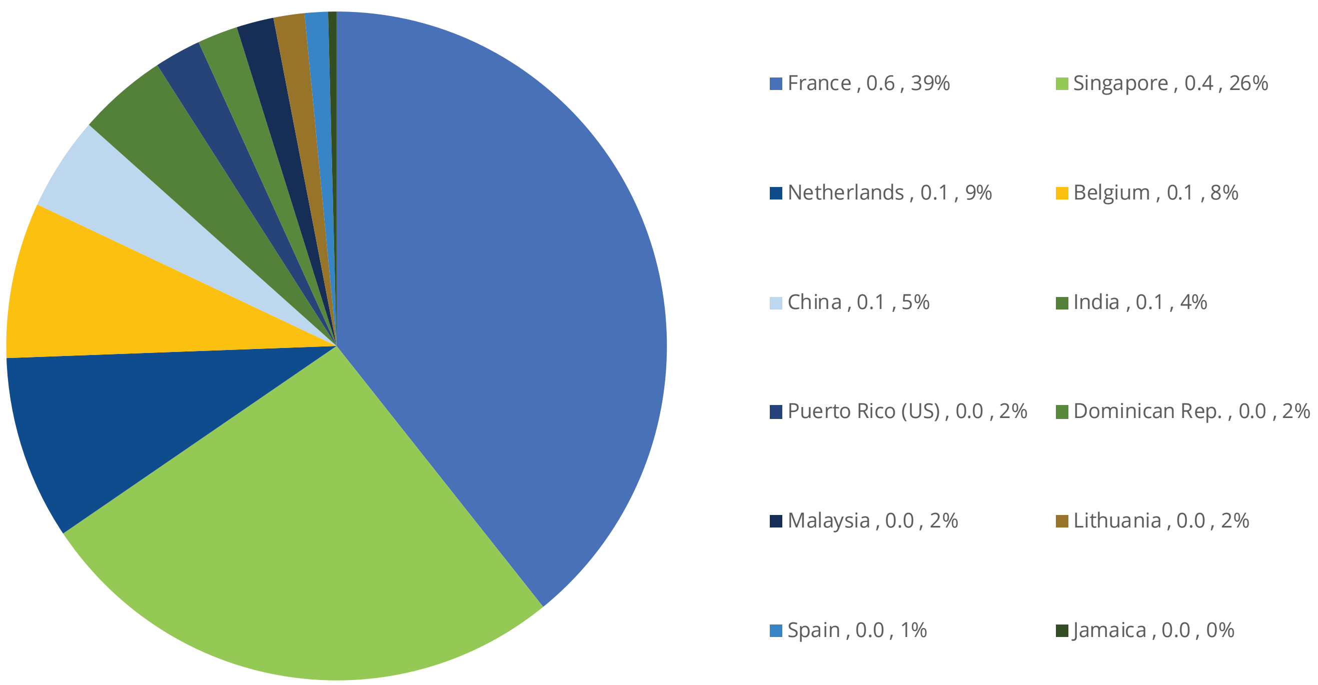
Figure 2.2: 2019 Incremental LNG Exports by Market Relative to 2018 (in MT)



Source : GIIGNL

Re-exported trade dropped in 2019 by 59% from 3.8 MT to 1.6 MT – equal to roughly 0.4% of global trade in 2019. 12 Markets re-exported volumes, with some marked shifts from 2018. For example, China, Malaysia, Lithuania and Jamaica loaded re-export volumes, whereas they did not do so in 2018. The Dominican Republic was the only market that re-exported volumes both in 2018 and 2019, and also increased their re-exports, although only marginally (+0.01 MT). Europe re-exported 58% of global re-exports in 2019, and France and Singapore had the highest re-export loadings in 2019, re-exporting 0.6 MT and 0.4 MT respectively.

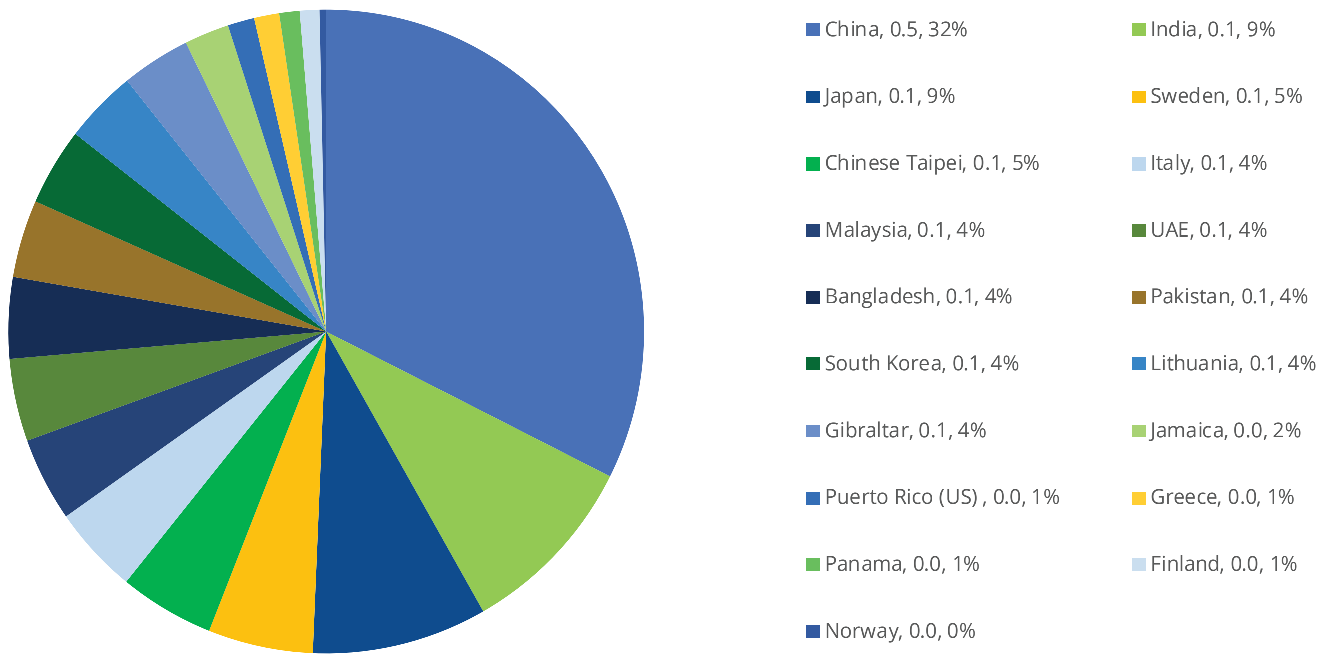
Figure 2.3: Re-Exports Loaded by Re-loading Market in 2019 (in MT)



Source : GIIGNL

At the same time, 19 markets received re-exported volumes, versus 22 markets in 2018. New receivers of re-exported volumes in 2019, who did not do so in 2018, were Bangladesh, Malaysia, Gibraltar, Greece, Italy, Lithuania, Norway, Jamaica and Panama. China received the highest volume of re-exports at 0.5 MT.

Figure 2.4: Re-Exports Received in 2019 by Receiving Market (in MT)



Source : GIIGNL

As already forecasted in the 2019 IGU World LNG Report, a lower price environment was likely to trigger a drop in re-exports, as the opportunities for inter-basin arbitrage plays decreased. This was clearly observed in 2019, as despite a continued ramp-up of Yamal volumes that were expected to be re-loaded at European terminals, re-exports from Europe dropped by around 70%. Even though a number of new markets were involved in the loading of re-exports and received re-exports, the volumes were too small to offset the significant drop in re-exports from Europe.

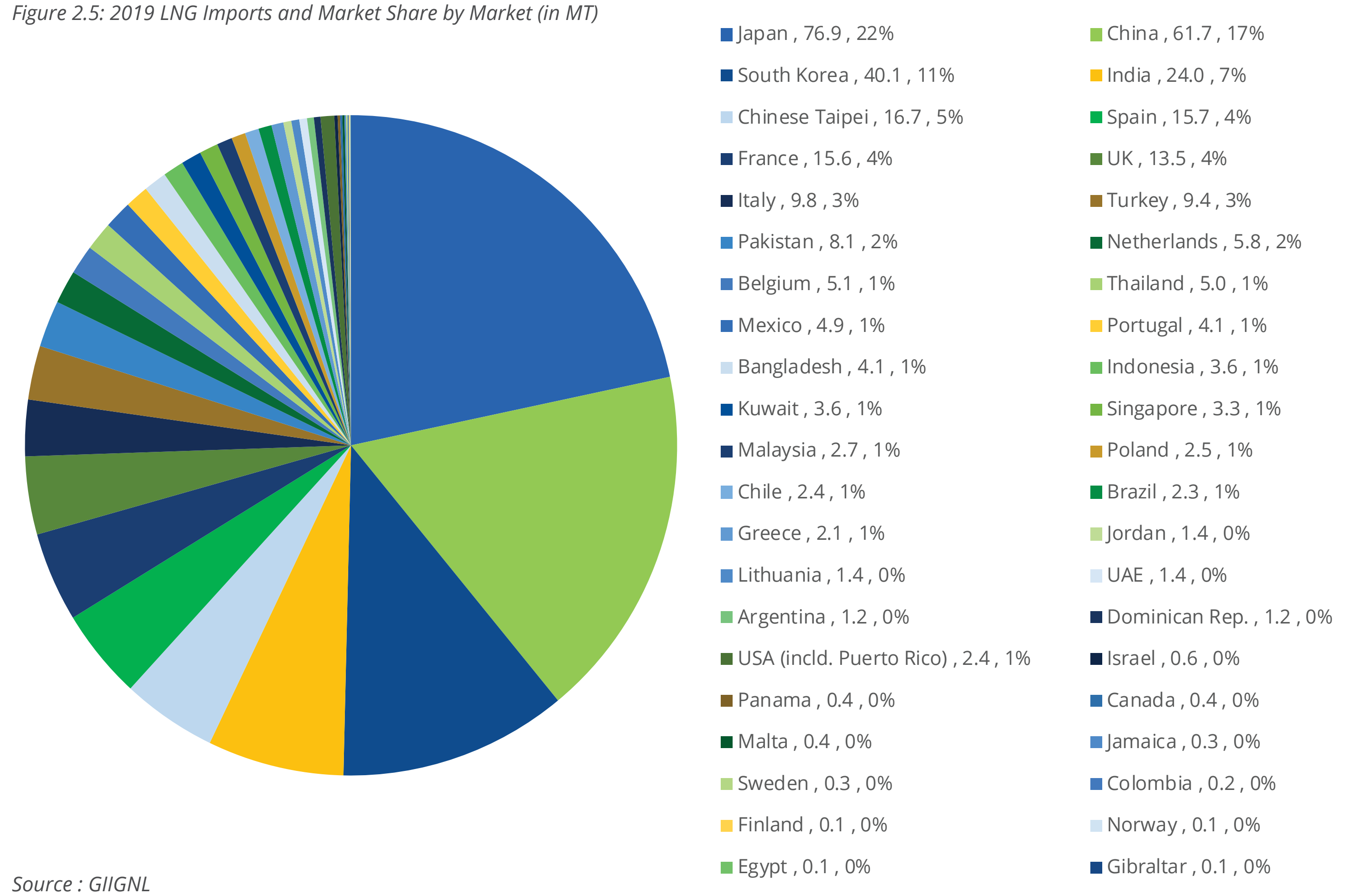
LNG Vessel at Shell's Terminal at Hazira – Courtesy of Shell

2.3 LNG IMPORTS BY MARKET

While new regasification facilities were commissioned in new markets in 2019, none imported cargoes by the end of December, and hence no new importers were added to the list in 2019. However, most recent new importers (that started importing between 2015 and 2018) increased imports further in 2019, such as Bangladesh (+3.4 MT), Pakistan (+1.2 MT), Poland (+0.5 MT) and Panama (+0.3 MT). The largest increases in imports were seen in Europe, with the UK, France, Spain, the Netherlands, Italy and Belgium alone adding 32 MT of imports in 2019.

The largest importing regions, consistent with 2018, were Asia Pacific and Asia (131.7 MT and 114.5 MT respectively), although Asia Pacific's market share of total LNG imports declined by 7% compared to 2018.

Figure 2.5: 2019 LNG Imports and Market Share by Market (in MT)



Source : GIIGNL

Demand from Asia Pacific was supported through growth in imports into Malaysia, Singapore, Indonesia and Thailand, but was challenged by declining imports in South Korea and Japan (approximately -9% or -3.8 MT and -7% or -5.6 MT respectively), driven by milder weather, the price environment and changes in domestic energy mixes and demand.

While Asia's market share remained stable with support from China, Pakistan and Bangladesh, India's demand growth was muted compared to the growth seen in 2018 and prior years (+1.5 MT) with infrastructure development slower than expected, and imports into Chinese Taipei dropped by 0.2 MT. China's growth in LNG imports slowed down on the back of slower coal-to-gas switching efforts, increased domestic production and an increase of renewables in the energy mix.

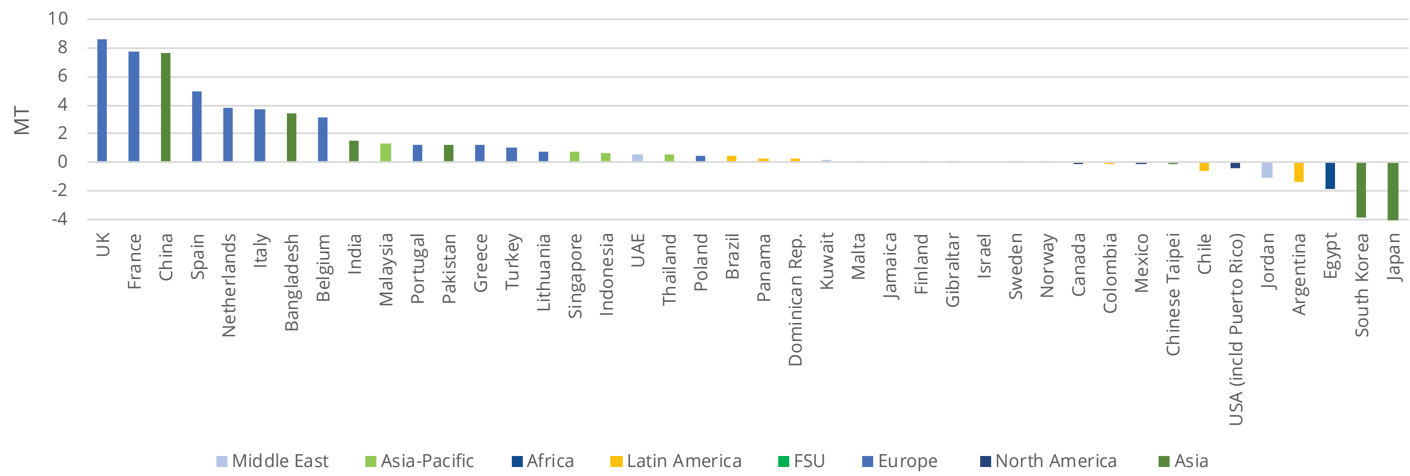
European imports surged on the back of low prices, almost doubling to 85.9 MT from 48.9 MT in 2018. This accounts for 90% of the global increase in LNG trade in 2019. Market share wise, this meant an increase from 16% to 24%. This was driven also by declines in domestic production, increased use of storage, additional gas-fired power generation and increases in LNG imports from for instance Algeria as LNG was competitive versus pipeline supplies.

Both Africa and Latin America reversed earlier growth trajectories in import, with Egypt and Argentina becoming exporters again after having previously imported LNG. Chile's LNG imports also dropped as Argentina supplied more pipeline gas.

In North America, Puerto Rico was the only market to grow LNG import further after 2018 showed recovery following Hurricane Maria. While pipeline capacity additions in Mexico continue to be delayed, LNG imports into Mexico remained relatively stable at 4.9 MT.

Lastly, in the Middle East, the UAE increased imports by 0.6 MT, but Jordan's imports decreased by 1 MT as Jordan reduced pipeline exports to Egypt further.

Figure 2.6: Incremental 2019 LNG Imports by Market & Incremental Change Relative to 2018 (in MT)



Source : GIIGNL

2.4 LNG INTERREGIONAL TRADE

The largest global LNG trade flow route continues to be intra-Asia Pacific trade (77.3 MT), driven mainly by continued ramp up in exports from Australia, and to a lesser extent additional exports from Papua New Guinea and Malaysia, into the largest market of the world – Japan, as well as a large flow into Singapore, Indonesia, Thailand and South Korea. Interestingly 3.6 MT was intra-Indonesian trade. Most of the remaining supply out of Asia Pacific ended up in Asia, being the second largest LNG trade flow in 2019 – 54 MT with 28 MT from Australia to China alone.

The third largest trade flow is from the Middle East to Asia at 36.3 MT – with most of those supplies being exported from Qatar. There were also significant flows from the Middle East to Asia Pacific, which was the second largest trade flow last year, but has now settled at 31.2 MT. A lot of the trade flow that used to go to Asia instead moved to Europe in 2019 as prices went down. Intra-Middle East trade was only 3 MT.

African exports flowed mainly to Europe and Asia (25.1 MT and 13.6 MT respectively), supported by additional exports from Algeria and Egypt, and overall demand growth in for example China and Bangladesh. 2.9 MT of African supply was imported into Asia Pacific, a drop from last year, while notably 1.5 MT was imported into North America, an increase from last year, almost all of this went to Mexico.

North American supplies were similarly globally distributed as they were in 2018 with volumes being imported into Europe, Asia Pacific, Latin America, Asia, North America and the Middle East. The largest flow was, predictably given 2019's price developments, into Europe (12.7 MT), but significant flows also went to Asia Pacific (9.5 MT).

FSU (Russia) exports topped at 29.3 MT, of which more than half was destined for Europe in 2019. A significant volume also went to Asia Pacific (8.8 MT), mainly Japan (6.3 MT), as the Northern Sea route trade flow grew steadily.

Latin American volumes showed a similar global distribution in 2018 and 2019 as North American volumes. Intra-Latin American trade decreased, and instead more volumes went to Europe (5.9 MT) and Asia (1.9 MT). Imports into North America remained similar to last year (3.1 MT).

Lastly, European volumes remained within Europe (4.2 MT), meaning Norway's lowered exports were mainly imported into other European markets, with almost half destined for France (1 MT) and Lithuania (1 MT).

Table 2.1: LNG Trade Between Regions, 2019 (in MT)

Exporting Region / Importing Region	Asia-Pacific	Middle East	Africa	North America	Former Soviet Union	Latin America	Europe	Reexports Received	Reexports Loaded	Total
Asia-Pacific	77.3	31.2	2.9	9.5	8.8	2.1	-	0.3	0.4	**131.7**
Asia	54.2	36.3	13.6	3.0	4.8	1.9	0.1	0.8	0.1	**114.5**
Europe	-	23.5	25.1	12.7	15.1	5.9	4.2	0.3	0.9	**85.9**
Latin America	-	-	0.8	4.2	-	2.6	0.4	0.1	-	**8.1**
North America	0.2	-	1.5	2.9	0.1	3.1	-	-	-	**7.7**
Middle East	0.1	3.0	1.0	1.4	0.6	0.8	-	0.1	-	**6.9**
Africa	-	-	0.1	-	-	-	-	-	-	**0.1**
Total	**131.7**	**93.9**	**45.0**	**33.8**	**29.3**	**16.3**	**4.7**	**1.6**	**1.6**	**354.7**

Source : GIIGNL

Table 2.2: LNG Trade Volumes Between Markets, 2019 (in MT)

Exporting Markets / Importing Markets	Algeria	Angola	Argentina	Australia	Brunei	Cameroon	Egypt	Equatorial Guinea	Indonesia	Malaysia	Nigeria	Norway	Oman	Papua New Guinea	Peru	Qatar	Russia	Trinidad & Tobago	UAE	USA	Re-exports Received	Re-exports Loaded	2019 IMPORTS	2018 IMPORTS
Bangladesh	0.3	-	-	-	-	-	0.1	-	0.1	0.1	0.4	-	0.1	-	-	2.8	0.3	-	-	-	0.1	-	4.1	0.7
China	0.1	0.1	-	28.2	0.6	0.5	0.2	0.4	4.5	7.5	2.0	0.1	1.1	2.8	0.7	8.5	2.8	0.8	0.1	0.3	0.5	0.1	61.7	54.0
Chinese Taipei	-	-	-	4.4	0.2	0.1	0.1	0.1	0.4	2.5	0.2	-	0.1	1.5	0.1	4.7	1.5	0.2	0.1	0.5	0.1	-	16.7	16.8
India	0.2	2.9	-	1.0	-	0.4	0.2	0.5	-	0.4	2.7	0.1	1.0	-	-	9.7	0.2	0.1	2.6	1.8	0.1	0.1	24.0	22.4
Pakistan	0.3	-	-	-	-	-	0.6	0.2	-	0.1	1.0	-	0.3	-	-	4.8	-	-	0.4	0.5	0.1	-	8.1	6.9
ASIA	0.8	3.0	-	33.6	0.8	1.0	1.2	1.3	5.0	10.6	6.2	0.1	2.6	4.2	0.8	30.4	4.8	1.1	3.2	3.0	0.8	0.1	114.5	100.8
Indonesia	-	-	-	0.1	-	-	-	-	3.6	-	-	-	-	-	-	0.0	-	-	-	-	-	-	3.6	3.0
Japan	0.1	-	-	29.8	4.3	-	0.1	0.1	4.0	9.4	0.8	-	2.9	3.7	0.7	8.7	6.3	-	2.2	3.6	0.1	-	76.9	82.5
Malaysia	-	-	-	1.5	0.7	-	-	0.1	-	0.3	0.1	-	-	-	-	-	-	-	-	0.1	0.1	-	2.7	1.4
Singapore	-	0.1	-	1.9	-	-	0.4	0.3	0.1	-	0.1	-	-	-	-	0.1	-	0.1	-	0.6	-	0.4	3.3	2.6
South Korea	-	-	-	7.6	0.6	-	0.1	0.1	2.3	4.7	0.6	-	3.9	0.3	1.1	11.1	2.4	0.1	0.2	5.0	0.1	-	40.1	43.9
Thailand	-	0.1	-	0.8	-	-	0.1	-	0.3	1.3	0.0	-	0.1	-	0.1	2.0	0.1	0.1	-	0.1	-	-	5.0	4.4
ASIA-PACIFIC	0.1	0.1	-	41.8	5.6	-	0.7	0.5	10.3	15.7	1.5	-	6.9	4.0	1.9	21.9	8.8	0.2	2.4	9.5	0.3	0.4	131.7	137.8
Belgium	-	0.1	-	-	-	-	0.1	-	-	-	-	-	-	-	-	3.3	1.4	-	-	0.3	-	0.1	5.1	1.9
Finland	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	0.1	0.1
France	2.7	0.3	-	-	-	-	0.3	-	-	-	3.0	1.1	-	-	0.3	1.3	5.0	0.2	-	2.0	-	0.6	15.6	7.8
Gibraltar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	-	-	-	-	0.1	-	0.1	-
Greece	0.4	0.1	-	-	-	-	0.2	-	-	-	0.3	0.4	-	-	-	0.4	0.1	-	-	0.2	-	-	2.1	0.9
Italy	2.2	-	-	-	-	-	0.3	0.1	-	-	0.1	0.1	-	-	-	4.7	0.1	1.1	-	1.2	0.1	-	9.8	6.1
Lithuania	-	-	-	-	-	-	-	-	-	-	-	1.0	-	-	-	-	0.3	-	-	0.1	0.1	-	1.4	0.6
Malta	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	0.3	-	-	-	-	0.4	0.3
Netherlands	0.1	0.2	-	-	-	-	-	-	-	-	0.2	0.3	-	-	0.3	0.1	3.1	0.1	-	1.4	-	0.1	5.8	2.0
Norway	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	0.1	0.1
Poland	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	1.7	-	-	-	0.7	-	-	2.5	2.0
Portugal	0.1	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	0.5	0.1	0.1	-	1.0	-	-	4.1	2.9
Spain	0.8	0.2	-	-	-	0.1	-	0.1	-	-	3.1	0.5	-	-	0.3	3.2	2.3	2.1	-	3.1	-	-	15.7	10.7
Sweden	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	0.1	-	-	-	0.1	-	0.3	0.2
Turkey	4.3	-	-	-	-	-	0.3	0.1	-	-	1.8	0.1	-	-	-	1.8	0.1	0.3	-	0.7	-	-	9.4	8.3
UK	0.7	0.1	-	-	-	0.1	-	0.2	-	-	0.3	0.3	-	-	0.2	6.6	2.4	0.7	-	2.1	-	-	13.5	5.0
EUROPE	11.3	0.9	-	-	-	0.1	1.3	0.4	-	-	11.2	4.2	-	-	1.2	23.5	15.1	4.7	-	12.7	0.3	0.9	85.9	48.9
Argentina	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	-	0.7	-	-	1.2	2.6
Brazil	-	0.1	0.1	-	-	0.1	-	0.1	-	-	0.2	0.2	-	-	-	-	-	0.4	-	1.1	-	-	2.3	1.9
Chile	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	0.6	-	1.7	-	-	2.4	3.1
Colombia	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	0.1	-	-	0.2	0.3
Panama	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	0.1	-	0.2	-	-	0.4	0.2
Dominican Rep.	-	-	-	-	-	-	-	-	-	-	0.1	0.1	-	-	-	-	-	0.9	-	0.2	-	-	1.2	0.9
Jamaica	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	-	0.2	-	-	0.3	0.2
LATIN AMERICA	-	0.1	0.1	-	-	0.1	-	0.3	-	-	0.3	0.4	-	-	-	-	-	2.5	-	4.2	0.1	-	8.1	9.0
Canada	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	-	-	-	-	0.4	0.4
Mexico	-	-	-	-	-	-	-	0.3	0.2	-	1.0	-	-	-	-	-	-	0.4	-	2.9	-	-	4.9	5.0
USA (incld. Puerto Rico)	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	-	0.1	2.3	-	-	-	-	2.4	2.8
NORTH AMERICA	-	0.1	-	-	-	-	-	0.3	0.2	-	1.1	-	-	-	-	-	0.1	3.1	-	2.9	-	-	7.7	8.2
Egypt	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	1.9
AFRICA	-	-	-	-	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	1.9
Israel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.4	-	-	-	-	0.6	0.5
Jordan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.4	0.2	-	0.8	-	-	1.4	2.5
Kuwait	0.1	0.1	-	-	-	-	0.1	-	-	-	0.4	-	0.7	-	-	1.8	-	0.1	-	0.2	-	-	3.6	3.4
UAE	-	0.1	-	0.1	-	-	0.1	-	-	-	0.1	-	0.1	-	-	-	0.1	0.1	0.3	0.4	0.1	-	1.4	0.8
MIDDLE EAST	0.1	0.3	-	0.1	-	-	0.1	-	-	-	0.5	-	0.8	-	-	1.9	0.6	0.8	0.3	1.4	0.1	-	6.9	7.2
2019 EXPORTS	12.2	4.4	0.1	75.4	6.4	1.3	3.5	2.8	15.5	26.2	20.8	4.7	10.3	8.2	3.8	77.8	29.3	12.5	5.8	33.8	1.6	1.6	354.7	-
2018 EXPORTS	10.1	4.0	-	66.7	6.4	0.6	1.4	3.4	18.2	24.7	19.7	5.2	10.0	7.0	3.5	76.8	18.3	11.6	5.5	20.6	3.8	3.8	-	313.8

Source : GIIGNL

3 LNG and Gas Pricing

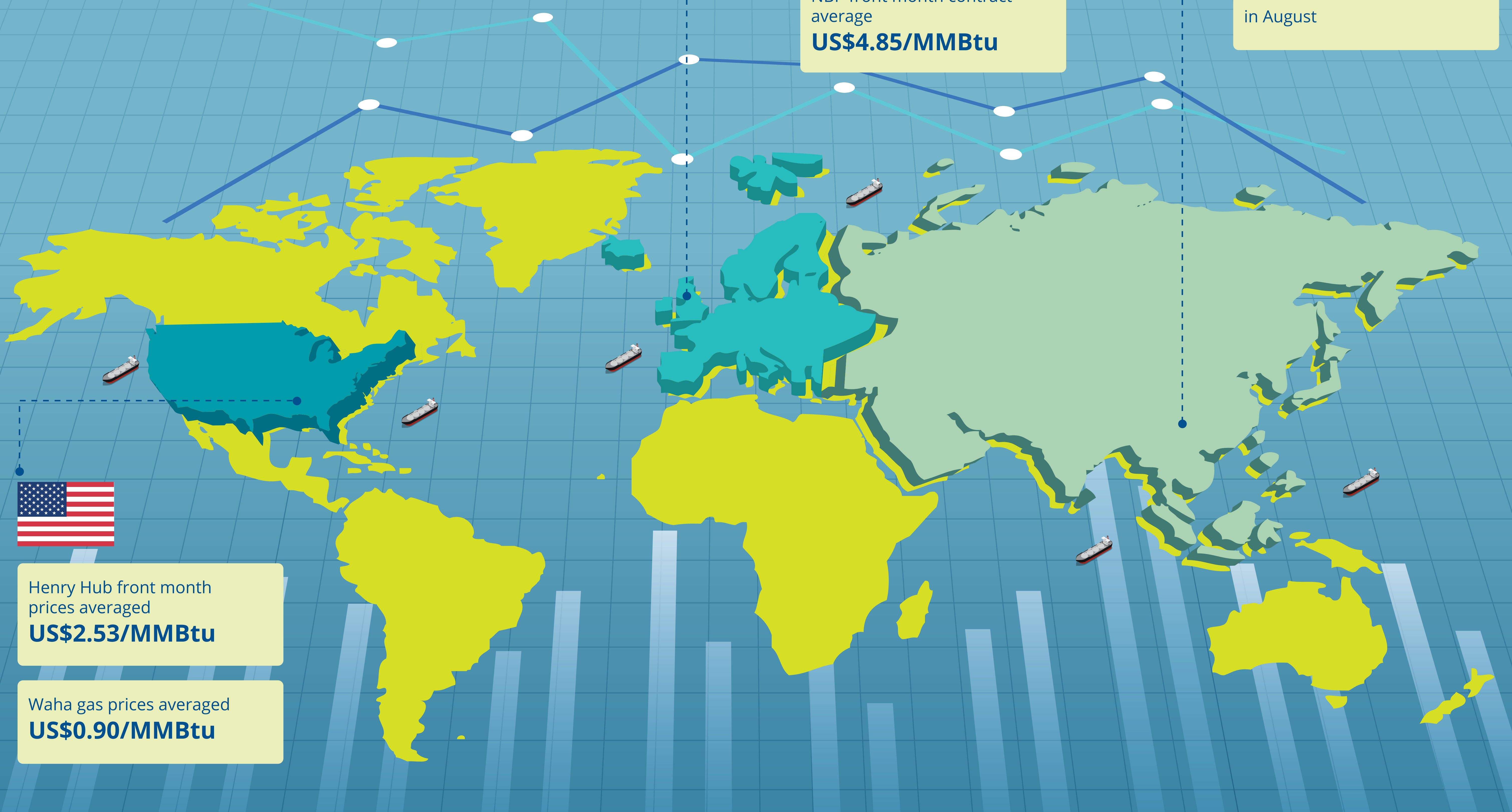
International gas prices hit a record low in 2019.

NBP front month contract trading reached lowest level in 10 years -
US$3.15/MMBtu
in July

NBP front month contract average
US$4.85/MMBtu

Asian spot average
US$5.49/MMBtu, lowest in 10 years

Asian spot reached a low of
US$4.10/MMBtu
in August



Henry Hub front month prices averaged
US$2.53/MMBtu

Waha gas prices averaged
US$0.90/MMBtu

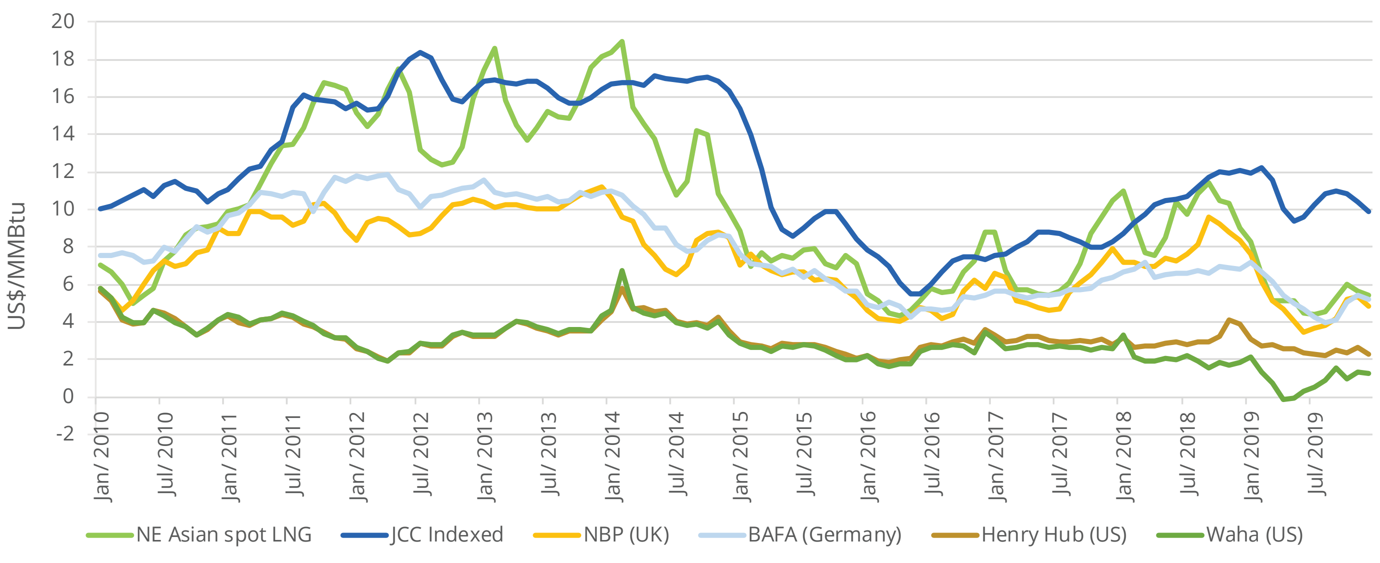
3.0 LNG and Gas Pricing

International gas prices reached record low levels in 2019 driven by increasing natural gas production, the commissioning of new export infrastructure and limited demand response from Asian markets.

Turquoise P FSRU - Courtesy of Pardus Energy

3.1 OVERVIEW

Figure 3.1: Monthly Average Regional Gas Prices 2010-2020



Source: Rystad Energy, Bloomberg, Refinitiv

US$2.53/MMBtu
Average Henry Hub
Front Month Prices, 2019

International gas prices reached record low levels in 2019 driven by increasing natural gas production, the commissioning of new export infrastructure and limited demand response from Asian markets.

In the US, Henry Hub front month prices averaged US$2.53 per MMBtu in 2019 compared to US$3.07 per MMBtu in 2018, dented by robust production growth from shale plays. Despite seeing a significant amount of coal-to-gas switching and an increase in LNG exports during 2019, these developments have not been significant enough to absorb the gas supply growth, leading to an overall decline in prices.

Total US natural gas supply increased from 850 Bcm in 2018 to 935 Bcm in 2019, an increase of 10% year-on-year. The Marcellus and Utica shales (in the Appalachia Basin) accounted for 45 Bcm of the growth in supply as new pipeline capacity supported sending the low cost gas out of the region. Another 27 Bcm was added from the Haynesville/Bossier Basin, which was made possible by improved well parameters for US shale wells. Longer laterals and higher proppant intensity contributed to lowered costs and improved well performance.

Associated gas supplies from oil fields have also flooded the US market. The Permian Delaware and Permian Midland tight oil plays increased natural gas supply from 2018 to 2019 by about 23 Bcm combined. These volumes are considered as zero cost gas as they are driven by oil activity and oil prices. This has put Western Texas gas prices under pressure during 2019.

As a result of the increase in production and local oversupply in Permian, Waha gas prices averaged US$0.9 per MMBtu in 2019, down from US$2.01 per MMBtu in 2018. The Waha spot price turned negative for a two-week period in April 2019. This deflated price was triggered by a depression in local gas prices over the last few quarters as well as a bottleneck created by a mismatch in production growth and infrastructure to send volumes to market. A seasonal gas demand decline was aggravated further by the failure of two compressor stations within the El Paso Natural Gas Pipeline System. Even though the capacity reduction was relatively small, the impact on prices was dramatic, with the elasticity of local spot prices taking an especially hard hit.

After the summer of 2019, Waha prices recovered as new infrastructure helped debottleneck the Permian Basin. The Gulf Coast Express pipeline commenced operations in September 2019 and is capable of transporting about 20 Bcm of natural gas eastward to the Agua Dulce receipt point near the Texas Gulf Coast. Since the commissioning of the pipeline, Waha prices averaged US$1.21 per MMBtu up to the end of 2019. However, there has been no material increase in West Texas exports to Mexico due to ongoing infrastructure build-out delays in Mexico.

Demand response across the US helped absorb some of the additional supplies coming into the market but this was not enough to prevent prices from falling. US natural gas demand increased from 851 Bcm in 2018 to 875 Bcm in 2019, mostly driven by the power sector as it became cheaper to generate power with gas than coal in most states. US LNG exports also increased from 30 Bcm in 2018 to about 50 Bcm in 2019 while net pipeline imports declined slightly by about 5 Bcm per annum. Despite the higher demand, gas flaring increased in 2019 as infrastructure bottlenecks prevented delivery of all volumes into the market.

In Asia, spot LNG prices averaged US$5.49 per MMBtu in 2019[1], the lowest level in the last ten years. After reaching a peak of US$11.6 per MMBtu at the end of September 2018 driven by Asian buyers re-stocking ahead of the winter, prices had a prolonged slide throughout 2019, reaching a low of US$4.1 per MMBtu in August. The decline in prices was caused by a mild winter in both Asia and Europe and a continuous increase in LNG supplies mainly from the US but also from Russia, Australia and others.

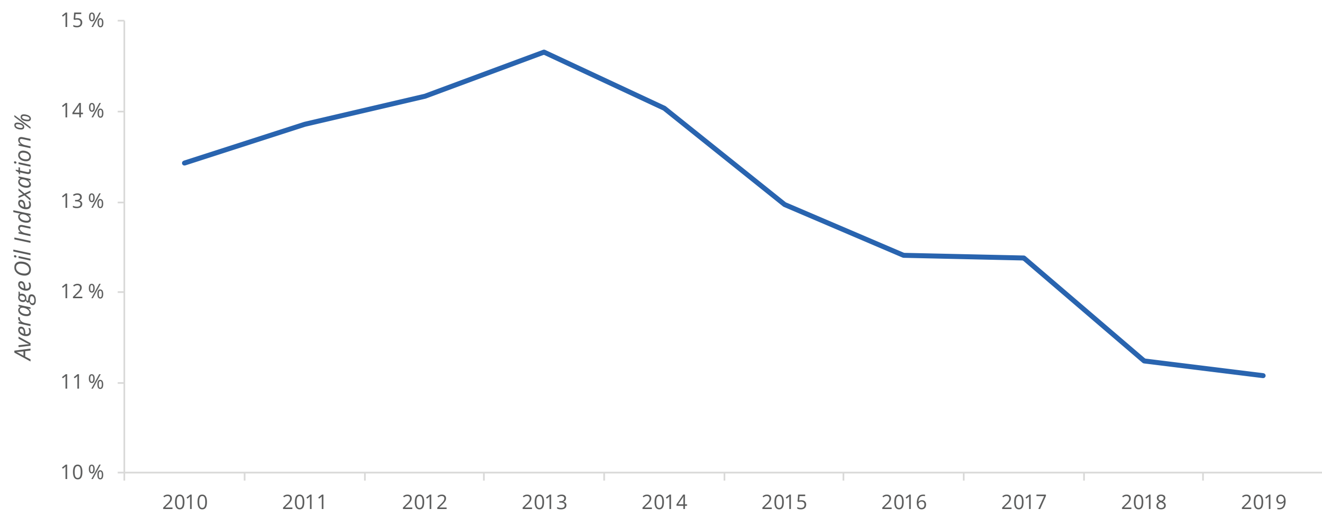
[1] Source: Refinitiv

Given that LNG demand in Asia was flat year-on-year throughout the summer of 2019, more and more volumes headed to Europe due to the region's liquid markets and the slightly higher netback. This resulted in a very loose European balance as pipeline exports from Russia and Norway remained steady. As a result, European prices also reached a historical low with the NBP front month contract trading as low as US$3.15 per MMBtu in July 2019[1], the lowest level in ten years. The NBP front month contract averaged US$4.85 per MMBtu in 2019[1].

At the start of the winter, Northwest European prices jumped to a level above US$5 per MMBtu, an increase of more than 25% driven by normal winter seasonality and some uncertainty regarding Russian exports through Ukraine. Despite the slight bump, winter prices remained at the lowest level in ten years. Asian prices also increased in line with winter demand, but prices remained at a historical low level for the winter period, ending 2019 at only US$5.10 per MMBtu. Netbacks remained in favour of Europe, signalling the continued looseness in the international market. The German Border Price (BAFA) averaged US$5.26 per MMBtu in 2019. This reflects an average premium of US$0.4 compared to NBP during 2019, in contrast to 2018 when BAFA traded US$1.14 below NBP on average. As opposed to the NBP, the price formation at BAFA is still heavily influenced by the oil price as a consequence of the large amount of Russian imported volumes that are traded via long-term contracts indexed to Brent. Hence, the average landed price of natural gas imported to Germany traded at a premium compared to NBP in 2019, as the oil price traded at a stable level compared to the NBP, which plummeted during the same period. The drop in European and Asian spot prices has resulted in wider spreads between oil-indexed contracts and spot prices. Asian spot prices tend to reach oil-indexed levels during winters to attract flexible cargoes during periods of market tightness. In September 2018, the spread between the JCC oil-indexed price and the Asia Spot price was only US$0.30 per MMBtu, but widened to reach a maximum spread of US$6.71 per MMBtu in August 2019 and ended the year at a level of US$4.80 per MMBtu.

With spot gas prices reaching record low levels, recent market fundaments have also changed and have been reflected in LNG contractual terms. Historically, most LNG contracts have been indexed to oil. The Fukushima disaster in 2011 drove up global gas prices and pushed the average oil indexation level to above 14%, but that indexation has gradually declined again over the past years. First, the collapse in oil prices in 2015 brought the average slope down to 12% in 2016. Subsequently, lower gas spot prices drove down the oil indexation to an average level of 11% starting from late 2018.

Figure 3.2: LNG Sales and Purchase Agreements (SPAs) Average Oil Indexation by Signature Year, Percent



Source: Rystad Energy

The abundance of shale volumes being produced and exported from the US has made Henry Hub a global gas price reference. US LNG exporters have created new business models and tend to sell their gas indexed to Henry Hub. While oil indexation is still common in Sales and Purchase Agreements (SPAs), there is an increasing trend to tie LNG contracts to European gas prices (NBP and TTF), the Japan/Korea Marker (JKM) and other hybrid pricing models involving multiple commodities. In April 2019, Shell and Tokyo Gas grabbed the entire world's attention by signing the world's first LNG contract indexed to coal. In 2019, around 68% of volumes sold through long-term contracts were indexed to oil while 24% were indexed to Henry Hub.

Long-term contracts continue to play an important role in securing financing for the development of the liquefaction projects and supplies to importing markets. Out of the 362 MTPA sold through SPAs during the past 10 years, 271 MTPA was sold with a contract duration of more than 10 years. As an example, the 12.88 MTPA Mozambique LNG Area 1 recently managed to lock 11.18 MTPA, or 87% of its nameplate capacity, into long-term contracts before reaching FID in June 2019. The typical new LNG SPA contract duration is now 11-20 years, rather than 20+ years which was a common practice in the past.

The global LNG market is becoming more financially liquid, transparent and competitive, and requires improved risk management. The need for flexible supply and demand is challenging traditional business models in the LNG industry. A total of 36.8 MTPA of SPAs was signed in 2019, out of which 43% (15.8 MTPA) did not specify final destinations. The trend of portfolio allocation has been well observed on the demand side as well. LNG buyers are diversifying LNG sources, allocating volumes to whichever destination that offers the best economics.

The first quarter of 2020 has proven to be very challenging for natural gas and LNG producers, as historically low gas prices have prevailed throughout the winter season. First, the increase in LNG exports combined with a mild winter across the Northern Hemisphere lead to a counter-cyclical drop in international gas prices. The bearish tone continued throughout February and March as markets around the world started to announce lockdowns in order to control the spread of the COVID-19 virus. The first to announce a lockdown was China, resulting in a drastic drop in LNG imports as a result of the lower industrial and commercial activity. As the epicenter moved from China to Europe, markets across the continent have started to take measures to control the spread of the virus. As of March 2020, it seems likely that more markets will decide on lockdowns. This will lead to depressed commercial and industrial activity around the world, which will have a negative impact on gas demand throughout this crisis. The current market environment lowers the expectations of seeing a recovery in prices any time before the coming winter.

4 Liquefaction Plants

Global liquefaction capacity reached **430.5 MTPA** in 2019.

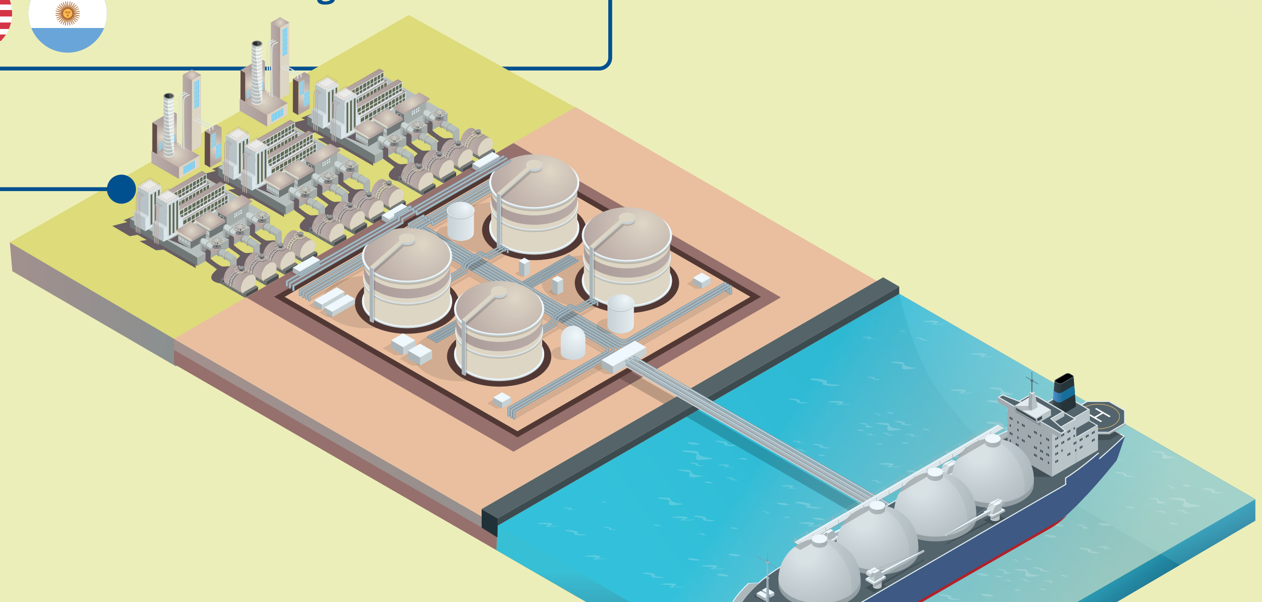
Capacity Additions for 2019

42.5MTPA
of liquefaction capacity brought online

11%
year-on-year growth vs 2018

Australia
87.6MTPA overtook **Qatar** **77.1**MTPA as the market with the highest liquefaction capacity

Capacity added in **Australia**, **Russia**, **USA** and **Argentina**



FIDs and Under Construction

Record FIDs of liquefaction projects, totalling
70.8MTPA

FIDs were taken in **USA**, **Mozambique**, **Russia** and **Nigeria**

Global liquefaction capacity forecasted to reach
454.8MTPA
by end 2020

Liquefaction capacity forecasted to be added in 2020 in **USA**, **Indonesia**, **Malaysia** and **Russia**

Pre-FID

907.4 MTPA
of liquefaction capacity currently in pre-FID stage

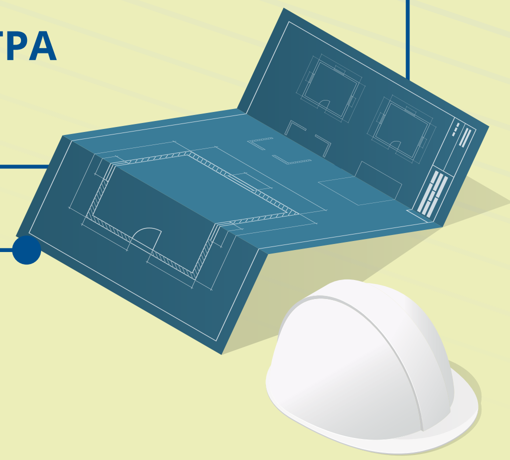
350.5MTPA from USA

221.8MTPA from Canada

50.0MTPA from Australia

49.0MTPA from Qatar

42.2MTPA from Russia



4.0 Liquefaction Plants

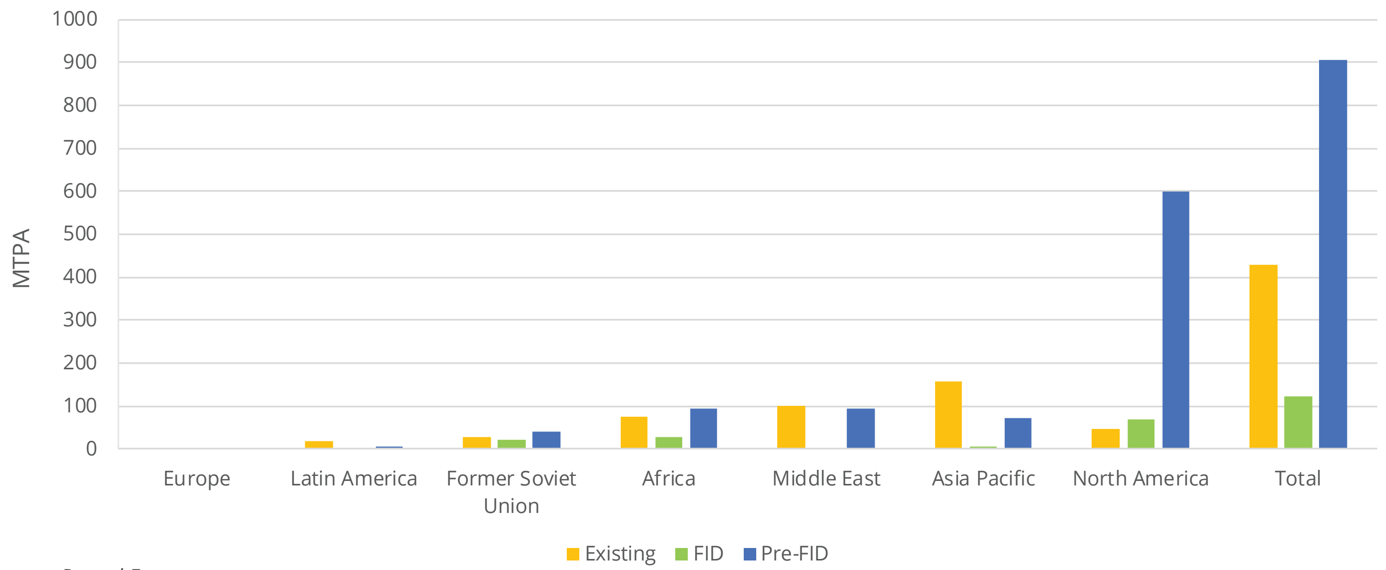
In 2019, around 42.5 MTPA of liquefaction capacity was brought online, increasing global liquefaction capacity to 430.5 MTPA[1]. This represents 11% year-on-year growth from 2018, well above the growth rate from 2017 to 2018. Ichthys LNG T1-2 (8.9 MTPA) and Yamal LNG T3 (5.5 MTPA) started up in late 2018, and began delivery of commercial cargoes in 2019. Corpus Christi LNG T1-2 (9 MTPA), Cameron LNG T1 (4.0 MTPA), Freeport LNG T1 (5.1 MTPA), Sabine Pass T5 (4.5 MTPA) and Elba Island T1-3 (0.75 MTPA) commenced commissioning activities in 2019 and began commercial operations later in the year, contributing to more than half of the capacity additions from North America alone. Prelude FLNG (3.6 MTPA) and Tango FLNG (0.5 MTPA) achieved commercial exports in June 2019, becoming the third and fourth operational FLNG developments in the world, after Petronas FLNG Satu (1.2 MTPA) and Cameroon FLNG (2.4 MTPA). Besides, Vysotsk LNG (0.66 MTPA) in Russia also commenced commercial operation in the year. Freeport T2 (5.1 MTPA) started commercial operation at the beginning of 2020, increasing global liquefaction capacity to 435.6 MTPA as of January 2020.

Tango FLNG - Courtesy of Exmar

[1] The number includes liquefaction capacity of Marsa El Brega LNG, Bontang LNG Train C-D, Yemen LNG and Damietta LNG, which have currently suspended operations. The number excludes liquefaction capacity of Kenai LNG, as parts of the LNG plant may be converted to an import terminal.

4.1 OVERVIEW

Figure 4.1: Global Liquefaction Capacity by Region and Status, as of December 2019



Source: Rystad Energy

Liquefaction capacity expansion is set to continue in 2020 and is expected to reach 24.35 MTPA in capacity additions. Freeport T2 (5.1 MTPA) started commercial deliveries in January 2020. Cameron LNG T2 (4.0 MTPA) produced its first LNG cargoes in late 2019, and the facilities are scheduled to start commercial deliveries in 2020. The ongoing site construction activities at Freeport LNG T3 (5.1 MTPA), Cameron LNG T3 (4 MTPA), Elba Island T4-T10 (1.75 MTPA) and Sengkang LNG T1 (0.5 MTPA)[2] are about to be completed and commercial operations can be expected by the end of 2020. In addition, Petronas FLNG Dua (1.5 MTPA) sailed away to the Rotan field in Malaysia in February 2020 and will start commercial deliveries 9 months later. In Russia, two mid-scale LNG plants, including Portovaya LNG T1 (1.5 MTPA) and Yamal LNG T4 (0.9 MTPA), are also aiming for commercial operation by the end of 2020. With those projects coming online, global liquefaction capacity is forecasted to further expand to 454.85 MTPA by the end of 2020.

2019 saw a record volume of sanctioned liquefaction projects, totaling 70.8 MTPA, compared to 21.5 MTPA in the previous year. Golden Pass LNG (15.6 MTPA) was sanctioned in February 2019, followed by the 12.9 MTPA Mozambique LNG (Area 1) FID in June 2019. Calcasieu Pass LNG (10 MTPA) and Arctic LNG 2 (19.8 MTPA) FIDs were announced in August and September 2019, respectively. Also, a few brownfield expansion plans received the greenlight for investment in 2019. Sabine Pass LNG, the first LNG export plant in service in the continental United States, took FID on its sixth train with a 4.5 MTPA capacity and NLNG reached FID on its 8 MTPA expansion plan in December 2019. The project includes a new 4.2 MTPA train and debottlenecking of existing facilities.

The record volume of sanctioned liquefaction projects is underpinned by the expectation of growing LNG demand globally, creating the need for additional liquefaction capacity. This will also lead to competition to secure EPC capacity, as project developers aim to enter the market by the mid-2020s in order to capture growing demand.

The United States continued to contribute significantly to LNG project sanctions in 2019, totaling 30.1 MTPA, thanks to the availability of abundant shale gas in the region. The African continent had 20.9 MTPA of liquefaction capacity sanctioned in 2019, driven by growing interest in commercialising the continent's rich gas resources. In East Africa, the sanctioning of Mozambique LNG (Area 1) is starting to change the role of Mozambique in global LNG supply. Currently, the market has no operational LNG facilities, but the sanctioning of Mozambique LNG (Area 1) in 2019 and Coral South FLNG in 2017, followed by a potential FID on Rovuma LNG (Area 4) in 2020 would allow Mozambique to emerge as the largest African LNG exporter. In West Africa, the 8 MTPA expansion project at NLNG reached FID at the end of 2019, after securing a 20-year gas supply deal, increasing NLNG's liquefaction capacity to 30 MTPA and reaffirming Nigeria's position as an important LNG hub. The sanctioning of Arctic LNG 2 shows growing interest in developing liquefaction facilities in the Arctic region, where projects are able to leverage abundant gas resources, geographic flexibility in exporting to both Europe and Asia, as well as take advantage of the climate for improved cooling efficiencies in the Arctic environment.

Long-term Sales and Purchase Agreements (SPAs) continued to play a key role in securing financing for certain LNG projects, as demonstrated by some of the new projects sanctioned in 2019. Mozambique LNG (Area 1) had close to 90% of its nameplate capacity under long-term SPAs at the time of FID. Calcasieu Pass LNG had signed 20-year SPAs with Shell, BP, Repsol, Edison, and a few other companies ahead of FID. The FID of Sabine Pass Train 6 was also underpinned by long-term offtake agreements with Petronas and Vitol, covering more than 40% of the new train's liquefaction capacity at the time of sanctioning.

However, as the global LNG market gets increasingly competitive and shorter-term contracts or spot deliveries become more common over time, LNG projects are taking more investment risks, taking FIDs without securing a significant number of long-term SPAs. Golden Pass LNG moved forward with FID in 2019, without announcing any long-term offtake contracts. Ocean LNG, a joint venture established by Qatar Petroleum and ExxonMobil, the two project owners, is responsible for marketing the produced LNG. The sanctioning of LNG Canada in 2018 was on a similar basis and the project was fully equity financed, rather than debt financing backed by long-term offtake agreements. Arctic LNG 2 reached FID with an expectation of equity partners offtaking LNG production proportionate to their ownership stakes, and the project may market a significant portion of production via spot deliveries.

Competition to secure long-term offtake contracts is also driving the development of small- to mid-scale LNG projects. Elba Island LNG bases its design on Moveable Modular Liquefaction System (MMLS) with a capacity of 0.25 MTPA per train. The required volume of long-term offtake to secure project financing is therefore significantly lower as compared to traditional large-scale LNG plants. Some projects also employ the concept of small- to mid-scale LNG trains and develop them in phases, depending on offtake sales. This method significantly reduces project investment risk. It also enables later phases to be financed by cash flow from earlier phases.

Portfolio contracts[3] offer flexibility for both suppliers and consumers. Under portfolio contracts, suppliers can send LNG cargoes to customers that bring the highest revenue while the buyers can diversify LNG sources, allocating volumes to destinations that offer the best economics. On the sell side, the percentage of portfolio volumes out of total contracted volumes globally has been on the rise. Portfolio volumes totaled 26% out of the volumes contracted between 2016 and 2019, compared to 20% between 2011 and 2015, and 10% between 2006 and 2010. On the buyer side, Shell, BP, Total, and Engie[4] have purchased the largest portfolio volumes without specifying the destinations of purchases. Japanese buyers have also shown interest in becoming portfolio players, as evidenced by redirecting excess volumes to other markets during periods of low domestic demand.

Currently, 907.4 MTPA of liquefaction capacity is in the pre-FID stage. Global liquefaction capacity could almost triple if all proposed projects materialise. The majority of the proposed capacity additions come from North America (599.6 MTPA), with 350.5 MTPA located in the United States, 221.8 MTPA in Canada and 27.4 MTPA in Mexico. Africa (93.3 MTPA), Asia Pacific (72.4 MTPA) and the Middle East (93.3 MTPA) follow North America, with significant proposed liquefaction capacity in the pipeline as well. 48.8 MTPA of liquefaction capacity is proposed in the rest of the world. However, not all of this planned capacity is needed and only the most competitive projects will move ahead.

Due to the low LNG prices in 2019, and into 2020 amid a global LNG supply surplus and uncertainties in the trade environment, some of the proposed projects are seeing slower progress towards FID. With the additional effect of COVID-19 on stock markets, many companies, including those in the energy industry, are struggling financially, further delaying progress of projects. However, the current LNG supply surplus situation could change if global LNG demand growth outpaces supply growth, which in turn would trigger new FIDs.

4.2. GLOBAL LIQUEFACTION CAPACITY AND UTILISATION

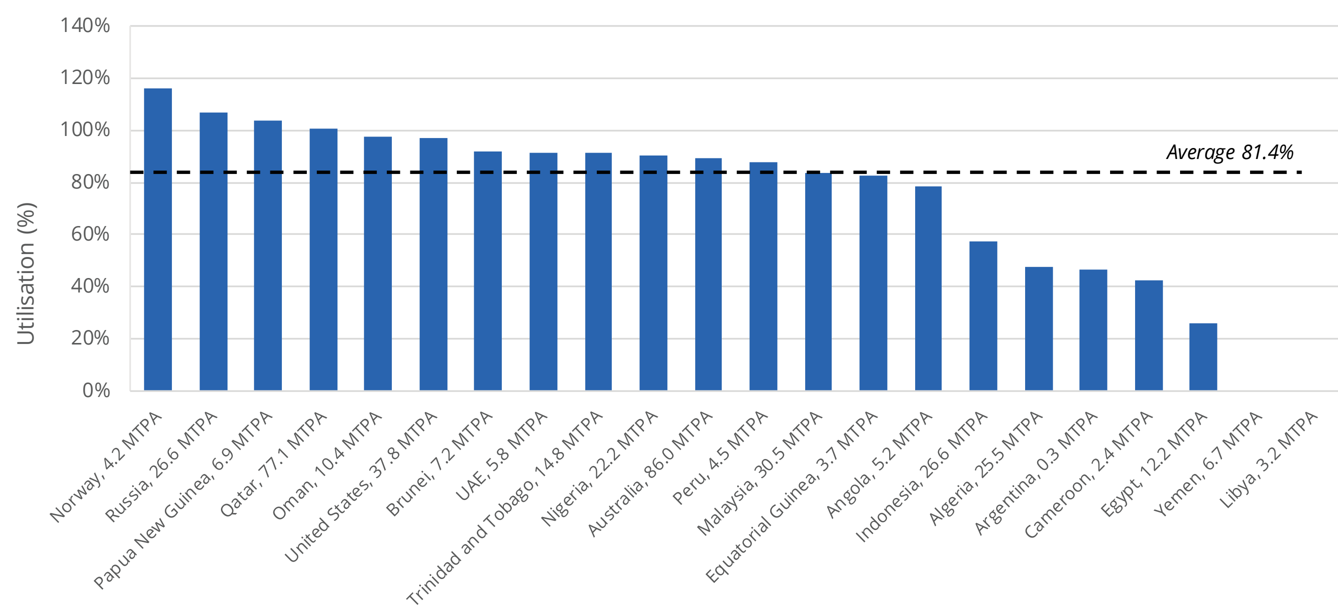
430.5 MTPA

Global Liquefaction Capacity, End of 2019

Global liquefaction capacity reached 430.5 MTPA at the end of 2019 and the utilisation rate was on average 81.4%[5].

10 out of 22 LNG exporting countries achieved utilisation rates of more than 90% in 2019, including Norway, Russia, Papua New Guinea, Qatar, Oman, the United States, Brunei, UAE, Trinidad and Tobago, and Nigeria.

Figure 4.2: Global Liquefaction Capacity Utilisation in 2019 (Capacity is Prorated)



Source: Rystad Energy, Refinitiv

The incremental supply of liquefaction capacity in 2019 was largely contributed by projects in the United States. Corpus Christi LNG T1-2 (9 MTPA), Cameron LNG T1 (4.0 MTPA), Freeport LNG T1 (5.1 MTPA), Sabine Pass T5 (4.5 MTPA) and Elba Island T1-3 (0.75 MTPA) collectively contributed 55% of the global capacity additions.

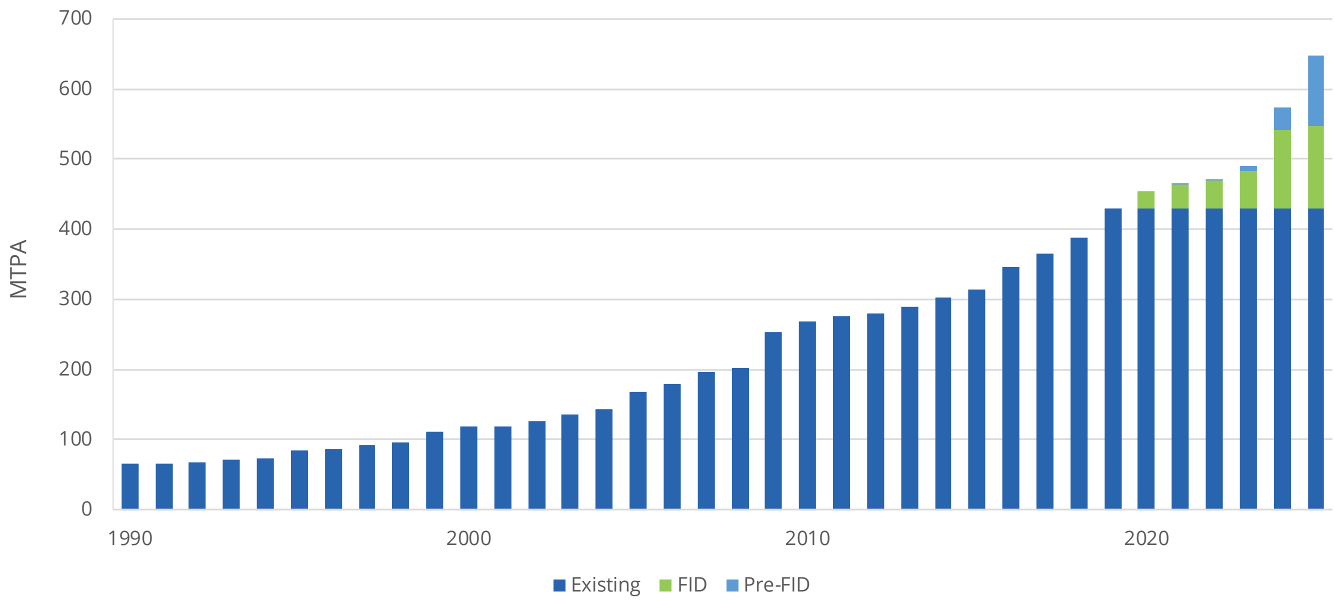
[2] Site construction at Sengkang LNG is close to completion. However, the project may face delays, subject to local authorities' approval on land use.

[3] Portfolio contracts are contracts that don't specify origins of supply or destinations of delivery. Thus, the seller can decide on where to supply each cargo from, and the buyer can decide where each cargo will be delivered.

[4] Engie's LNG portfolio was subsequently acquired by Total in 2018 (the deal was announced in 2017).

[5] The average utilisation excludes Yemen and Libya, which did not produce any LNG in 2019. Utilisation is calculated on a prorated basis, depending on when the plants are commissioned. Only operational capacity (including liquefaction capacity of Marsa El Brega LNG, Bontang LNG Train C-D, Yemen LNG and Damietta LNG) is included.

Figure 4.3: Global Liquefaction Capacity Development from 1990 to 2025



Source: Rystad Energy

Numerous factors affect the utilisation of LNG facilities globally. Feed gas availability is one of the most common factors limiting the output capacity of existing LNG facilities. Indonesia's Bontang LNG underwent a production downturn due to declining gas resources from the Mahakam block. The utilisation of Algeria's LNG export facilities sustained low levels[6], partly due to declining output from the large gas field Hassi R'Mel and delayed new field development in the southwest region. In contrast, debottlenecking of upstream gas supplies have increased the utilisation of a few LNG facilities. Idku LNG reached full export capacity in December 2019 for the first time in six years, owing to gas production from new fields coming online. Atlantic LNG in Trinidad and Tobago registered 91.1% utilisation in 2019 after a period of decline, thanks to the ramp-up of new fields.

Technical challenges affect the utilisation of existing LNG facilities as well. In June 2019, Pluto LNG experienced technical problems related to its mixed refrigerant compressor upon restart from turnaround maintenance, leading to an unplanned outage of the facility. Gorgon LNG Train 3 suffered a prolonged shutdown in mid-January 2019 due to mechanical issues. Unexpected technical problems can also lead to shorter (several-day) shutdowns, although the potential impact on utilisation can sometimes be offset by production creep.

Geopolitics have also affected utilisation of LNG facilities in 2019. Yemen LNG has not exported any LNG cargo since 2015, due to the ongoing civil war in the market. Legal issues have also delayed the restart of Damietta LNG in Egypt, which has not operated since early 2013 and negotiations to settle the legal dispute are ongoing.

DSLNG Tanker Aerial View - Courtesy of Kogas

[6] The low utilisation of Algeria's LNG export facilities in 2019 was also caused by explosion accidents, maintenance work and competition from pipeline gas exports.

4.3. LIQUEFACTION CAPACITY BY MARKET

124.6 MTPA

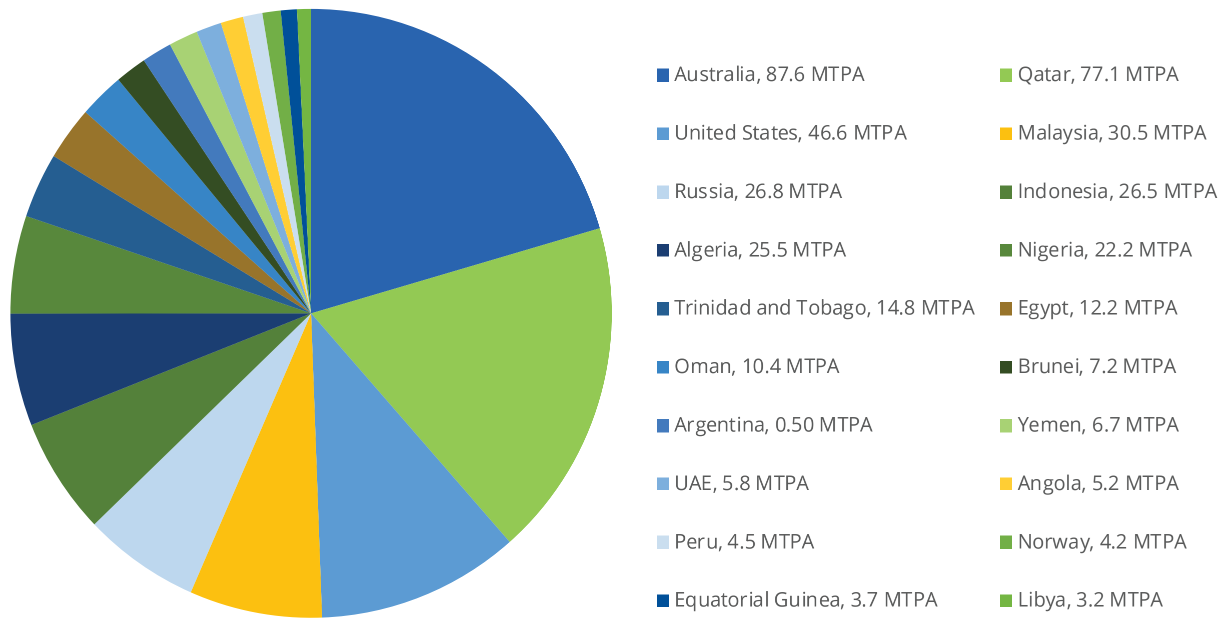
Liquefaction Capacity Under Construction, Dec 2019

Operational

As of December 2019, there were 22 markets[7] with operational LNG export facilities. Argentina became the 22nd LNG exporter with operational facilities when YPF shipped the first commercial cargo produced by Tango FLNG in October 2019. Prior to that, Cameroon started to export LNG, when Cameroon FLNG (also named Kribi FLNG) commenced commercial operation in June 2018. The United States, although being home to one of the oldest LNG plants in the world (Kenai LNG, 1.5 MTPA), only started its remarkable growth in liquefaction capacity when Sabine Pass LNG came online in 2016.

Australia (87.6 MTPA) overtook Qatar (77.1 MTPA) as the market with the highest liquefaction capacity as of December 2019. The capacity addition (12.5 MTPA) was contributed by Ichthys LNG T1-T2 and Prelude LNG. Significant capacity expansion in the United States added 23.35 MTPA of liquefaction capacity in 2019. This helped the United States to become the world's third-largest LNG producer, overtaking Malaysia and Russia. The top three LNG exporting markets currently represent close to 50% of global liquefaction capacity.

Figure 4.4: Global Operational Liquefaction Capacity by Market, 2019



Source: Rystad Energy

Under construction/FID

As of December 2019, 123.3 MTPA of liquefaction capacity was under construction or sanctioned for development. Close to 45% of this capacity is in the United States, and more than 55% is located in North America, where Golden Pass LNG (15.6 MTPA), Calcasieu Pass LNG (10 MTPA) and Sabine Pass LNG T6 (4.5 MTPA) commenced site construction in 2019. In Africa, Mozambique LNG (Area 1 (12.9 MTPA)) kicked off construction work in August 2019. The vessel conversion work for Tortue/Ahmeyim FLNG (2.5 MTPA) also started earlier in 2019.

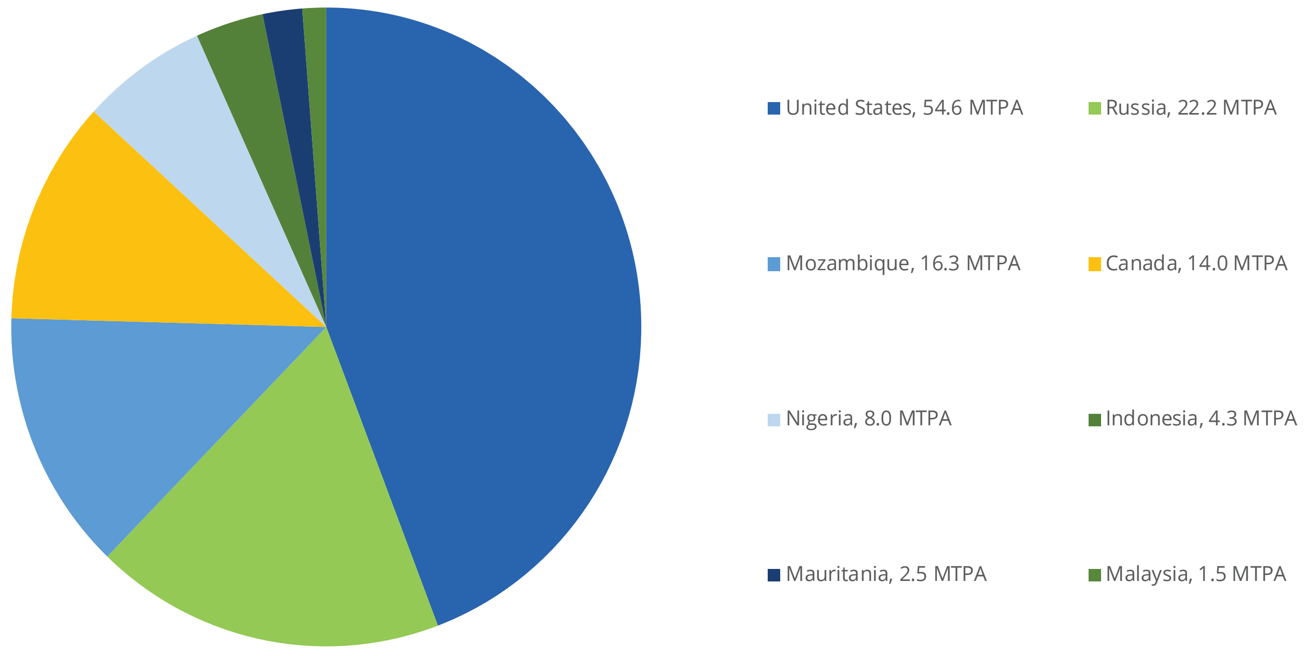
Many projects that commenced construction before 2019 are now undergoing commissioning activities. Elba Island T1-T3 (0.75 MTPA) produced its first commercial cargo at the end of 2019 and commissioning of the remaining trains is ongoing. Cameron LNG T2 (4.0 MTPA) and Freeport LNG T2 (5.1 MTPA) both shipped their commissioning cargoes in December 2019.

Other projects currently under construction are progressing towards completion. Projects scheduled to enter into commissioning in 2020 include Freeport LNG T3 (5.1 MTPA), Cameron LNG T3 (4 MTPA), Portovaya LNG (1.5 MTPA), PFLNG Dua (1.5 MTPA), Elba Island T4-T10 (1.75 MTPA), Yamal LNG T4 (0.9 MTPA) and Sengkang LNG (0.5 MTPA)[8]. Corpus Christi T3 (4.5 MTPA) and Tangguh LNG T3 (3.8 MTPA) are expected to enter into service in 2021, followed by Coral South FLNG (3.4 MTPA) in 2022.

Arctic LNG 2 (19.8 MTPA) and NLNG Train 7 (8.0 MTPA), as newly sanctioned projects, are in the process of preparing for construction.

[7] The 22 markets include Yemen and Libya, although Yemen LNG and Marsa El Brega LNG have suspended operations.
[8] Site construction at Sengkang LNG is close to completion. However, the project may face delays, subject to local authorities' approval on land use

Figure 4.5: Global Sanctioned Liquefaction Capacity by Market, 2019

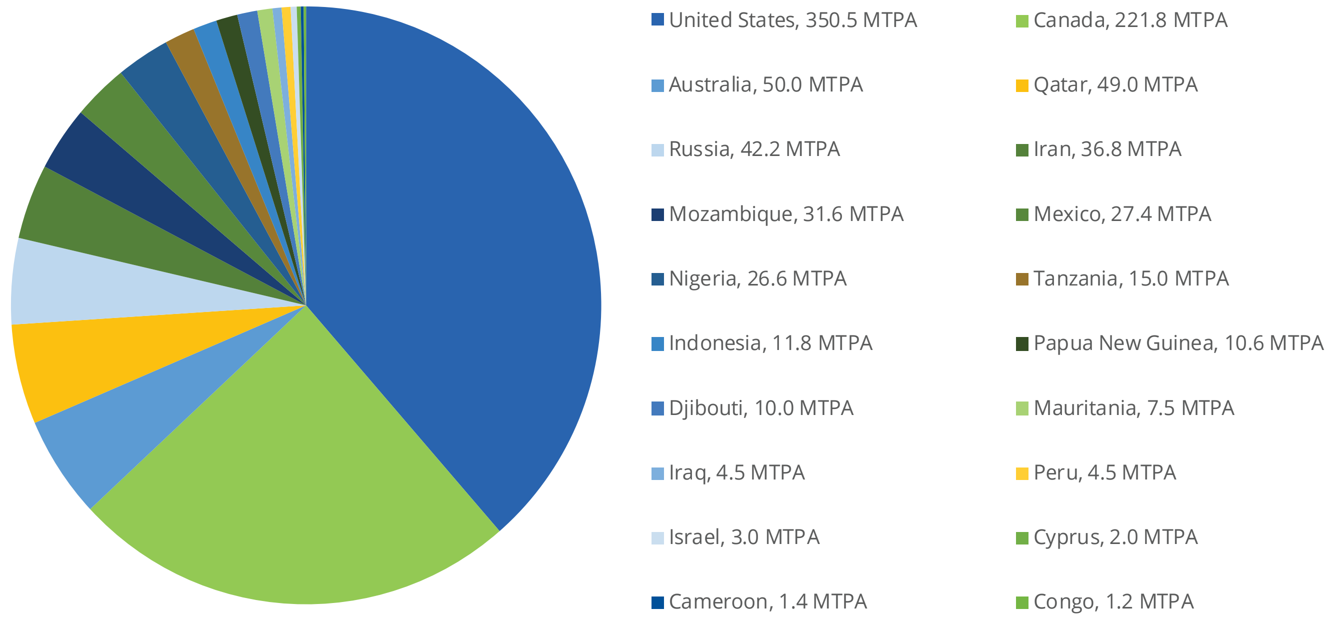


Source: Rystad Energy

Proposed

Currently, there is 907.4 MTPA of liquefaction capacity in the pre-FID stage. Shorter-term flexible offtake contracts are increasingly favored by buyers in the LNG market due to demand uncertainty caused by market liberalisation and the increase of renewables in the energy mix. The near-term supply surplus coupled with increased contract flexibility, has led to stricter debt financing terms for LNG projects, due to the increased uncertainty in the markets. However, with current sanctioned liquefaction capacity, the market is expected to be short of liquefaction capacity by the mid-2020s. Some equity-financed projects backed by experienced developers were able to take FID without seeking long-term off-takers ahead of FID - Golden Pass LNG and LNG Canada being such examples.

Figure 4.6: Global Proposed Liquefaction Capacity by Market, 2019



Source: Rystad Energy

The growth in shale gas output has led to more than 350 MTPA of proposed liquefaction capacity in the US as producers are looking for new markets for their natural gas. While currently operational US LNG projects are dominated by brownfield conversion projects of existing import terminals, proposed US LNG projects are mainly greenfield projects. Many of those projects consist of multiple small- to mid-scale LNG trains developed in phases to address the challenges of securing long-term off-takers and increasing competitiveness in project economics. For example, the Corpus Christi Stage 3 expansion project plans to construct seven mid-scale trains with a total expected production capacity of approximately 10 MTPA. Plaquemines LNG (0.6 MTPA per train), Delta LNG (1.1 MTPA per train) and Driftwood LNG (1.4 MTPA per train) consist of multiple small- to mid-scale LNG trains developed in phases to address the challenges of securing long-term off-takers and increasing competitiveness in project economics. This type of development concept aims to secure smaller offtake contracts in the market and achieve lower project capital costs through modular construction. While many US LNG projects tap into the vast natural gas pipeline network, some players are looking to integrate LNG plants with upstream assets. For example, Tellurian is looking to integrate its Driftwood LNG project with upstream assets acquired by the company, to optimise the gas supply chain and realise potential cost savings.

Out of the 221.8 MTPA of liquefaction capacity proposed in Canada, 187.9 MTPA is situated along the Pacific coastline in British Columbia, which is closer to the growing Asian market than the liquefaction capacity located on the US Gulf Coast. Most of the proposed projects in British Columbia intend to use inland gas supply sources in Northeast British Columbia and Alberta. Such use requires costly pipelines and other associated infrastructure, on top of the high cost due to the greenfield nature of most projects. The high capital cost, together with broad concerns from First Nations communities and stringent environmental standards have halted or led to the cancellations of several proposals. In response to environmental concerns, many proposed projects in British Columbia, such as LNG Canada, Woodfibre LNG and Kitimat LNG, plan to largely or fully electrify LNG production with British Columbia's abundant hydroelectric resources, resulting in the lowest carbon emission footprint among LNG plants globally. Another 33.95 MTPA of liquefaction capacity is located on the Atlantic coastline in Canada and can leverage proximity to European import markets. These projects intend to source gas supplies from the eastern US, in addition to inland sources in Canada.

Russia has traditionally exported most of its gas through pipelines to Europe and just inaugurated its "Power of Siberia" pipeline to China in December 2019. Developing LNG liquefaction capacity is part of the Russian government's strategy to diversify gas exports by allowing flexible LNG trades to European and Asian markets without significant investments in pipeline infrastructure. Currently, it has 42.3 MTPA of liquefaction capacity proposed, in addition to Arctic LNG 2 (19.8 MTPA) sanctioned in 2019. In Eastern Russia, Far East LNG, also named Sakhalin-1 LNG (6.2 MTPA), is a major project in the pre-FID pipeline. It aims to commercialise produced gas from Sakhalin-1 gas fields. Sakhalin-2 LNG T3 (5.4 MTPA), another project in the pre-FID stage, may face difficulties with feed gas sources since plans to purchase feed gas from Sakhalin-1 gas fields were abandoned and the developed gas reserves in Sakhalin-2 region are not sufficient yet. In addition, there are the proposed developments Pechora LNG (2.6 MTPA) and the Ob LNG (4.8 MTPA) in the Arctic region. The latter is the third LNG project proposed by Novatek, after Novatek's successful operation of Yamal LNG and FID on Arctic 2. Leveraging the Yamal LNG T4 experience, the project will utilise Novatek's proprietary technologies. Another proposed project, Baltic LNG (10 MTPA), would be situated on the Baltic Sea Coast and targets the European market. Africa is home to many of the oldest LNG plants, most of which are located in North Africa. The recent gas discoveries on this continent have added 93.3 MTPA of proposed liquefaction capacity. In North Africa, Djibouti LNG is expected to bring 10 MTPA of liquefaction capacity online if the project is sanctioned and fully developed. In West Africa, 36.7 MTPA of liquefaction capacity is proposed with the majority coming from onshore greenfield and brownfield LNG projects in Nigeria. OK LNG (12.6 MTPA) and Brass LNG (10 MTPA) in Nigeria have both experienced significant delays due to various reasons. The remaining capacity proposed in West Africa is likely to be floating or platform-based LNG concepts, which can be an effective solution to develop offshore resources in Africa, eliminating extensive onshore construction and reducing potential security risks. Congo-Brazzaville FLNG (1.2 MTPA) is proposed, looking to monetise associated gas from the Eni-operated upstream oil project involving NewAge and SNPC. Another FLNG unit (1.4 MTPA) in Cameroon may also be considered by NewAge, sourcing gas from the Etinde Joint Venture where NewAge is the operator. The giant gas discovery off Senegal-Mauritania has underpinned the sanctioning of Tortue/Ahmeyim FLNG T1, and plans of constructing additional platform-based liquefaction facilities of capacity up to 7.5 MTPA in several phases are currently being studied. On the east side of the continent, the giant hydrocarbon discoveries in Mozambique over the past years have fueled LNG project development. Following the sanctioning of Mozambique LNG (Area 1) and Coral South FLNG, the Rovuma LNG (Area 4) FID is expected in 2020, after awarding the main EPC contract to TechnipFMC, JGC and Fluor Consortium in December 2019. The relatively shorter shipping distance to India and China from Mozambique could provide those projects with favorable market access. Tanzania is also planning its long-delayed first LNG plant (15 MTPA), expecting to start construction in 2022, although it is yet to take FID. In total, more than 46 MTPA of liquefaction capacity is proposed in East Africa, including the phase 2 expansion trains of Mozambique LNG (Area 1) and Rovuma LNG (Area 4). East Africa could therefore emerge as one of the key LNG producing regions in the future.

In Australia, Woodside is targeting FID on Pluto LNG T2 (5 MTPA) in 2020. However, as offshore gas fields mature and coal seam gas production declines faster than expected, investment in Australia is focused on upstream backfill projects rather than liquefaction projects. Woodside has proposed to develop the Browse area fields for North West Shelf LNG, the Julimar field for Wheatstone LNG T1-T2, the Pyxis field for Pluto LNG T1 and the Scarborough field for Pluto LNG T2. Santos is leading the development of the Barossa field to backfill Darwin LNG, while Inpex is considering Ichthys Phase 2 to feed its Ichthys LNG project. Development of further coal seam gas to LNG projects may be less likely in the future, given that current projects such as Queensland Curtis LNG, Australia Pacific LNG, and Gladstone LNG are already facing feed gas constraints. Significant investments in shale projects in the Northern Territory and Cooper Basin, as well as coal seam gas projects in the Bowen basin, are needed to revive the coal seam gas to LNG project pipeline.

In other Asia Pacific markets, Papua New Guinea has significant proposed liquefaction capacity (10.6 MTPA). The two major projects are the two-train Total-led Papua LNG (5.4 MTPA) and the single-train ExxonMobil-led PNG LNG T3 expansion (2.7 MTPA). If all proposed projects come online, Papua New Guinea can emerge as a key LNG exporter in the region, although the realisation of this may largely depend on fiscal terms. Around 11.8 MTPA of liquefaction capacity is also proposed in Indonesia, with the majority of the capacity coming from Abadi LNG (9.5 MTPA), which is now proposed as an onshore development.

In the Middle East, Qatar's proposed six-train expansion represents a 49 MTPA increase to 126 MTPA from the market's current liquefaction capacity of 77 MTPA. The expansion plan was announced in 2019 after the lifting of the moratorium on new gas development at the North Field in 2017. The project is targeting first LNG by 2024 and is in the tendering stage for onshore construction contracts. The invitation to tender for LNG carriers was also issued to shipbuilders in 2019 and the total number of vessels is still unknown. This could significantly strengthen Qatar's position in the global LNG market, amid fast liquefaction capacity growth in North America.

Decommissioned and Idle

There were no announcements of LNG plants being decommissioned in 2019.

Kenai LNG in the United States continues to remain idle. An application to the authorities to convert parts of the Kenai LNG plant to an LNG import terminal was filed in 2019, with a decision deadline set for March 2020. Yemen LNG remained shut down throughout 2019, although the government of Yemen intended to resume production of LNG earlier in 2019. The Marsa El Brega LNG plant in Libya halted production in 2011, and there is currently no plan to revive it. In Egypt, Damietta LNG, which ceased export shipments in 2013, is expecting to receive resumed gas supplies soon, pending further resolution of its legal dispute. Bontang LNG trains A and B, in Indonesia, were decommissioned, and trains C and D remained idle throughout 2019, primarily due to a shortage in supply gas.

More than 43 MTPA of existing LNG production trains are more than 35 years old as of December 2019, including trains at Marsa El Brega LNG, Brunei LNG, ADGAS LNG, Arzew LNG, Bontang LNG and MLNG.

4.4. LIQUEFACTION TECHNOLOGIES

Air Products Technologies Account For

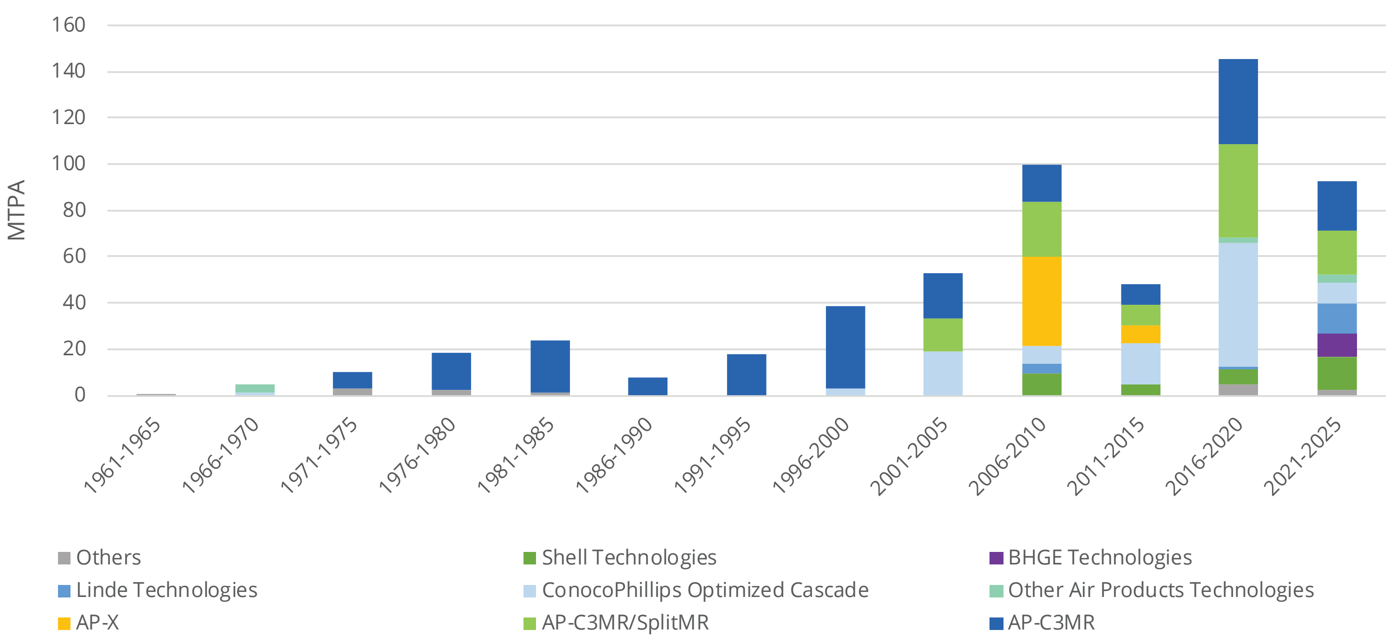
70% of Global Operational Capacity

The liquefaction trains that began operations in 2019 used a variety of liquefaction technologies, although Air Products technologies remained the most widely used, accounting for over 70% of operational capacity globally. Sabine Pass T5 and Corpus Christi T1 employed the ConocoPhillips Optimized Cascade Process. Black & Veatch's PRICO process was used at Tango FLNG, after its successful application in Cameroon FLNG, although Tango FLNG was originally designed and constructed earlier for Pacific Rubiales. Shell Prelude FLNG came online using Shell's proprietary Dual Mixed Refrigerant (DMR) process. Another Shell proprietary technology, Shell Movable Modular Liquefaction System (MMLS), is utilised in Elba Island LNG. Freeport LNG opted for Air Products' Propane Pre-cooled Mixed Refrigerant (C3MR) technology, which currently makes up over 40% of operational capacity globally (excluding the SplitMR variation).

The evolution of LNG liquefaction technology dates back to the early 1960s. Among the earliest LNG export facilities, Arzew GL4Z used the Pritchard Cascade process and Kenai LNG used the early version of the ConocoPhillips Optimized Cascade process. Air Products first entered into the liquefaction technology market with its Single Mixed Refrigerant technology (AP-SMR), implemented in Marsa El Brega LNG in 1970. The nameplate capacity for liquefaction trains was limited to 1.5 MTPA per train back then. However, the early facilities represent testing grounds for liquefaction technologies, which have continued its reliance on one method – cooling methane to approximately -162 degrees Celsius.

Since the AP-C3MR was first introduced in Brunei LNG in 1972, it has attained the dominating position among liquefaction technologies over the years, occupying close to 59% of operational capacity globally as of 2019 (including the SplitMR variation). The growing share of AP-C3MR technology (including the SplitMR variation) was driven by QatarGas in particular, totaling around 30 MTPA since the start-up of QatarGas 1 T1 in 1996. Damietta LNG was the first LNG plant to deploy the C3MR/SplitMR technology, which further improves AP-C3MR technology by optimising its machinery configuration, achieving higher turbine utilisation.

Figure 4.7: Installed and Future Sanctioned Liquefaction Capacity by Technology and Start-Up Year



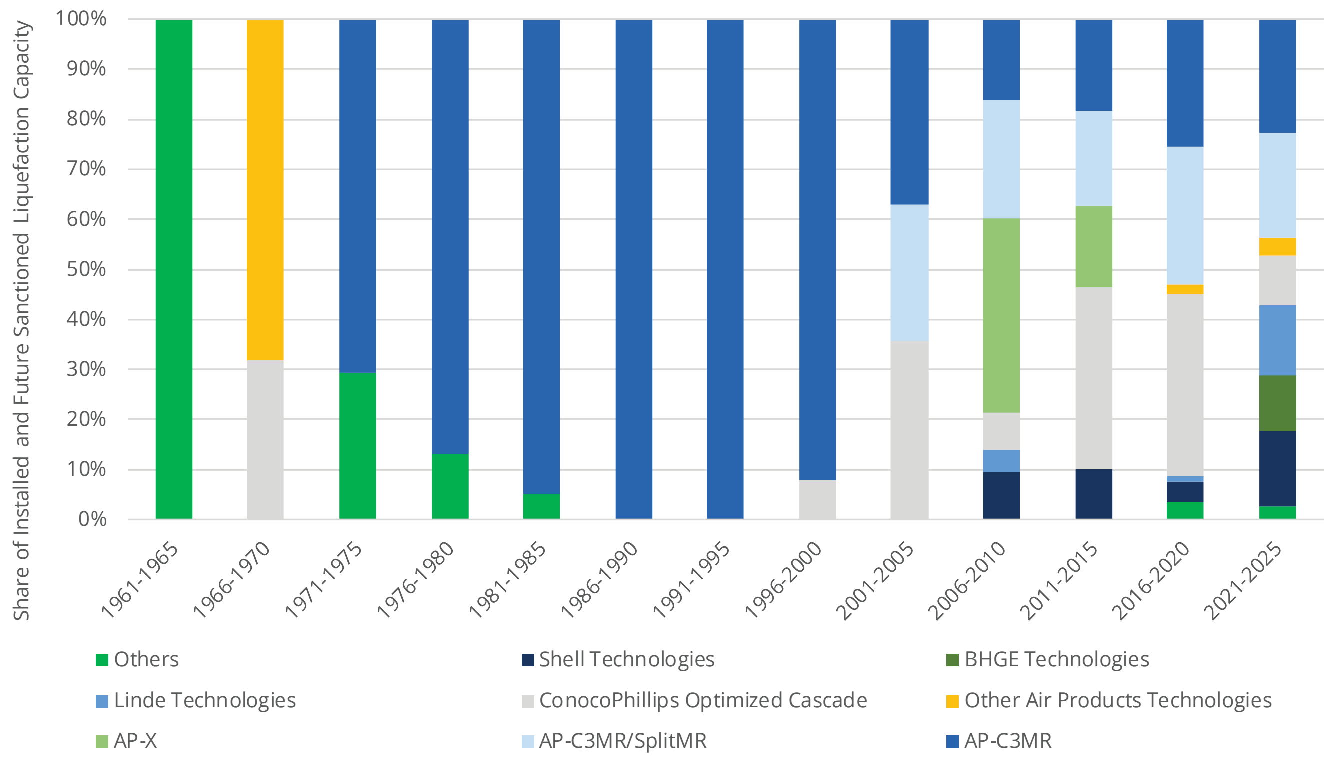
Source: Rystad Energy

Air Products' AP-X technology emerged in 2009 in the QatarGas 2 project, supporting 7.8 MTPA liquefaction capacity per train, the highest number achieved in the history of LNG developments. The high liquefaction capacity is achieved mainly through an additional nitrogen refrigeration loop to the C3MR technology for sub-cooling functions, effectively providing additional refrigeration power. A smaller-scale derivative of the AP-X subcooling technology, AP-N, has also been installed on Petronas FLNGs.

ConocoPhillips' Optimized Cascade Process was first used in Kenai LNG back in the late 1960s, and was next used in 1999 with the successful start-up of Atlantic LNG T1. It is currently the second leading technology in the market, after Air Products' AP-C3MR (including the SplitMR variation). 100.3 MTPA of operational liquefaction capacity uses the ConocoPhillips' Optimized Cascade Process, with two others under construction at Corpus Christi T3 and Sabine Pass T6. All of these trains have been designed and constructed by Bechtel.

From 2016 to 2020, 55% of capacity added or expected has used or will use technologies from Air Products, as compared to between 90% and 100% in the 1980s and 1990s. Competition mainly comes from the ConocoPhillips Optimized Cascade process, representing 36.6% of liquefaction capacity added in 2016-2020. However, Air Products' dominance can be reinforced again since QatarGas' expansion trains are likely to continue using Air Products' AP-X technology, and Rovuma LNG T1-T2 (15.2 MTPA on Air Products' AP-X technology) FID is expected in 2020.

Figure 4.8: Share of Installed and Future Sanctioned Liquefaction Capacity by Technology and Start-Up Year



Source: Rystad Energy

As the LNG industry moves towards 2021-2025, new entrants will further diversify the liquefaction technology market. The changing landscape is mainly attributed to the notable growth in small- to mid-scale LNG. As the interest to explore for smaller volumes of stranded gas grows and access to LNG project financing and off-takers becomes increasingly competitive, small- to mid-scale LNG trains could emerge as lower-risk alternatives for LNG plant developers. Owing to the smaller size of LNG trains and simpler configurations, the ease of standardisation and modularisation could also offer cost and execution time savings. In 2021-2025, Venture Global LNG is expected to start its Calcasieu Pass LNG (18 trains) on BHGE's Single Mixed Refrigerant (SMR) liquefaction technology, with each liquefaction train delivering 0.56 MTPA. Tortue/Ahmeyim FLNG will also come online with Black & Veatch's PRICO technology (0.6 MTPA per train, totaling 4 trains), which is already used in Tango FLNG. In Large-scale LNG, although the liquefaction technology market is less diversified, new technologies are also entering the market. The three-train Arctic 2 LNG project will employ Linde's MFC4 process, with each train having a capacity of 6.6 MTPA.

Operator-developed technology is also entering the market. Shell DMR technology will be used in LNG Canada (scheduled for start-up in 2024), after it was proven in Sakhalin 2 LNG and Prelude FLNG. Novatek's Arctic Cascade process, designed for the Arctic climate, will be used in Yamal LNG T4 (0.9 MTPA). CNPC has also developed its own DMR and cascade processes, used in its domestic LNG facilities, such as Taian LNG (0.6 MTPA) and Huanggang LNG (1.2 MTPA).

Small FLNGs, due to safety reasons (minimising highly flammable refrigerants) and space limitations with their small deck footprints, mostly use relatively simpler liquefaction technologies. The first operational FLNG, PFLNG Satu, uses Air Products' AP-N technology on a simple nitrogen cooling cycle. Black & Veatch's PRICO process was successfully applied in Cameroon FLNG. The smaller size modules of approximately 0.6 MTPA allow better configurations and better use of the limited deck space compared to larger trains. Increasingly complex technologies are seen in FLNGs with bigger capacity, such as Coral South FLNG (3.4 MTPA) on Air Products AP-DMR technology and Prelude FLNG (3.6 MTPA) on Shell DMR technology.

As governments and oil and gas companies form and implement decarbonisation commitments, LNG liquefaction facilities are increasingly adapting to low carbon emission designs, which employ highly efficient aero-derivative turbines and electrify the plant operation as much as possible. LNG Canada is an excellent example of that, taking advantage of Canada's abundant hydropower resources.

4.5. FLOATING LIQUEFACTION (LNG-FPSOs)

Shell's Prelude FLNG (3.6 MTPA)

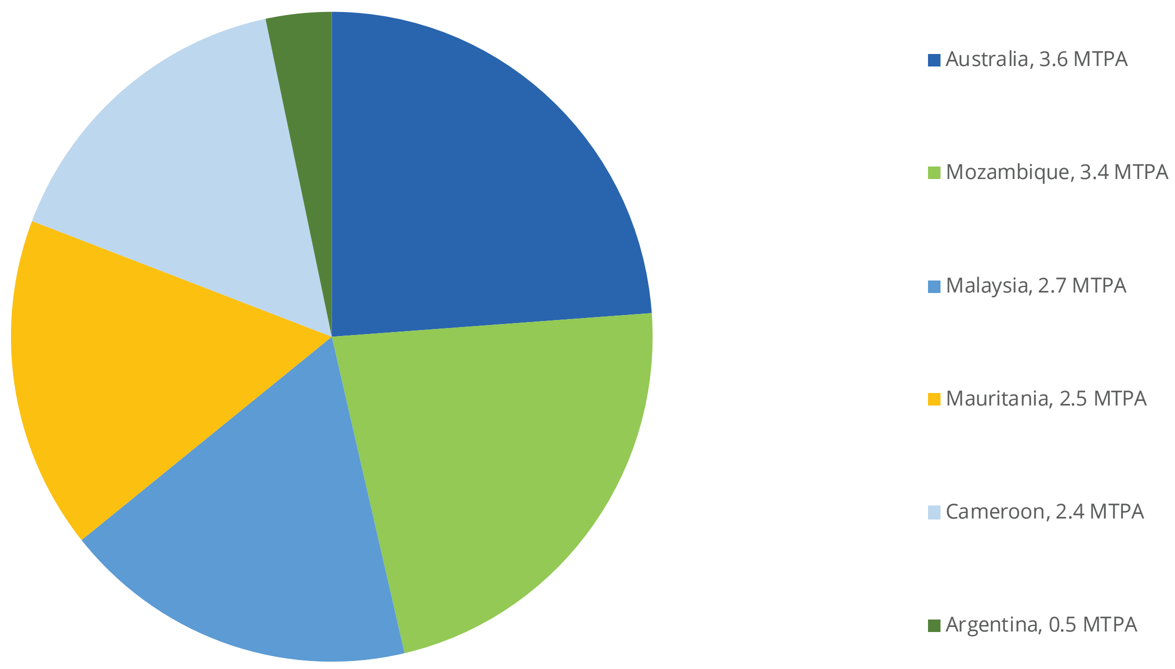
Online in 2019

Shell's Prelude FLNG (3.6 MTPA) came online in 2019, producing LNG from the Browse Basin offshore Western Australia. Exmar's Tango FLNG (0.5 MTPA) started production in 2019 as well, liquefying gas from onshore Vaca Muerta reserves while it is moored inshore at Bahia Blanca in Argentina. The commissioning of these two FLNGs follows the successful commissioning and start-up for Petronas PFLNG Satu in 2017 and Cameroon FLNG in 2018.

A key driver for FLNG developments is deployment flexibility, which allows more stranded gas resources to be commercialised without constructing expensive subsea pipelines to onshore LNG plants. An example of deployment flexibility was the relocation of PFLNG Satu in 2019. After successfully operating at Petronas' Kanowit field off Sarawak since 2017, the FLNG ship was relocated to the Kebabangan field in early 2019, and produced first LNG in May 2019.

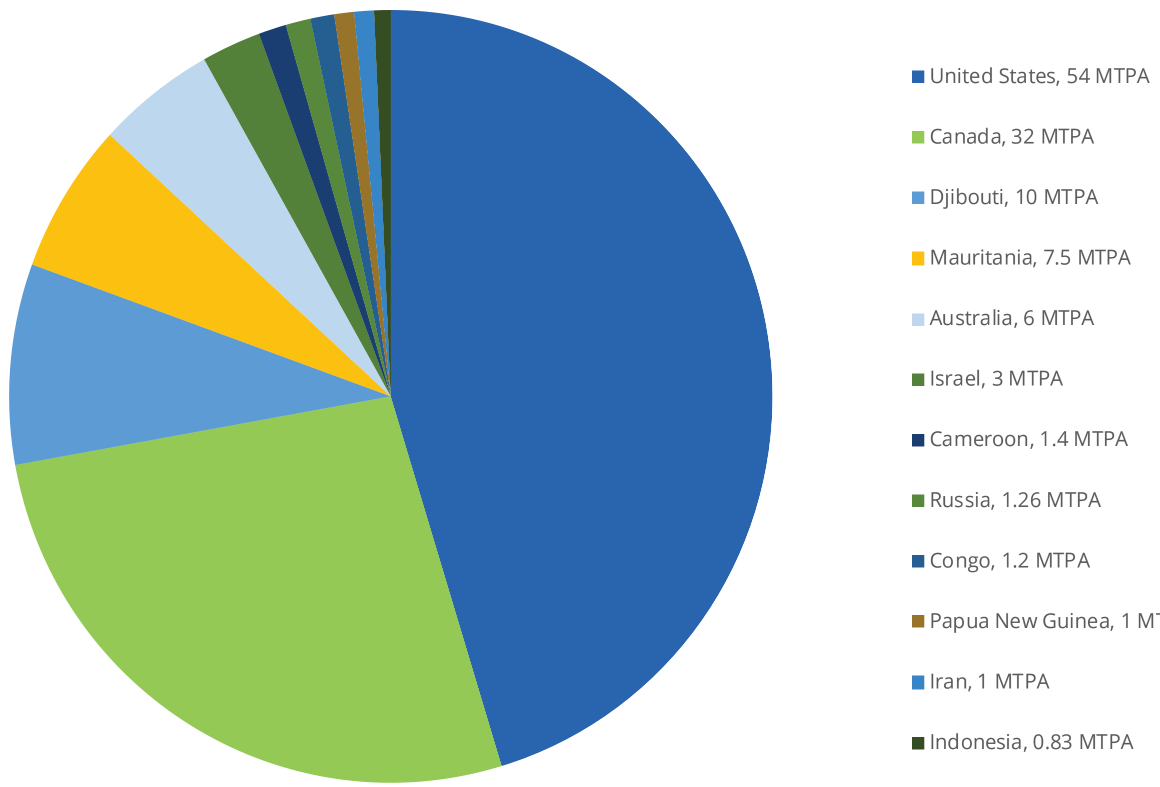
Three FLNGs are currently under construction. Petronas PFLNG Dua (1.5 MTPA) sailed away from the Samsung shipyard in Goeje Island, South Korea in February 2020. It will start to produce LNG from the deepwater Rotan gas field in November 2020. The ENI-led Coral South FLNG (3.4 MTPA), a project of similar capacity and complexity as Prelude (3.6 MTPA), reached a milestone when its ship hull was launched in South Korea in January 2020. It will be deployed to offshore Mozambique, in the southern part of Rovuma Basin Area 5. It will be the world's first ultra-deepwater FLNG facility to operate at a water depth of 2000 metres. Golar started the construction of Tortue/ Ahmeyim FLNG (also named Golar Gimi) in 2019, by converting a Moss LNG carrier built in 1976. It is scheduled to enter into service in 2022 and will be Golar's second FLNG vessel.

Figure 4.9: Global Operational and Sanctioned FLNG Liquefaction Capacity, 2019



Source: Rystad Energy

Figure 4.10: Global Proposed FLNG Liquefaction Capacity, 2019



Source: Rystad Energy

Currently, there is 119.2 MTPA of liquefaction capacity proposed under the FLNG development concept. Of the proposed capacity, 86 MTPA is in North America. Among the projects proposed in North America, Delfin FLNG (3.25 MTPA per vessel, 13 MTPA in total) is currently in FEED, which is being carried out by Samsung Heavy Industries and Black & Veatch. Instead of utilising the FLNG vessels for liquefying gas from remote offshore fields, Delfin LNG plans to liquefy onshore gas with pipelines connecting FLNGs moored nearshore to onshore pipeline networks. Such development concept aims to save both construction time and cost as compared to onshore LNG plants. It also adds flexibility for the vessel to be redeployed when onshore gas fields reach end of life or are no longer commercially viable to produce LNG. Interest in developing FLNG in Africa has also grown over recent years, with proposed capacity at 20.1 MTPA. In the rest of the world, there is 13.1 MTPA of FLNG liquefaction capacity proposed.

Many innovative development concepts and commercial structures have emerged for floating liquefaction, mainly owing to the flexible nature of FLNG. The locations of FLNGs are also increasingly flexible. The vessels do not need to be located at offshore gas fields, but can be moored inshore or nearshore to liquefy gas coming from onshore fields or pipelines, as demonstrated by the operational Tango FLNG.

While several FLNGs are utilising older converted LNG carriers (e.g. Golar Gimi and Golar Hilli Episeyo) as their bases — a conversion project in most cases requires lower cost and shorter delivery times — new build units can be tailor-made, particularly in terms of LNG and by-product storage capacity.

Most FLNGs, such as Petronas PFLNG Satu, PFLNG Dua, Shell Prelude and Coral South FLNG, are custom-designed new builds. In addition to the processing facilities onboard, these new build FLNGs include substantial LNG storage tanks. Prelude has six LNG storage tanks, each capable of holding 38,000 cubic metres (cm), plus 4 additional tanks for LPG and condensate storage.

While conversion of LNG carriers provides additional commercial pathways to implementing FLNG projects, third-party chartering also emerges as a new ownership structure for FLNG. Initially, FLNGs were developed and owned by operators who were engaged in offshore gas exploration and production activities. Third-party companies such as Golar and Exmar, are now chartering FLNG vessels to operators. For example, Golar Hilli Episeyo, is engaged in an 8-year liquefaction chartering engagement with Perenco. Exmar-owned Tango FLNG is contracted by YPF under a 10-year tolling agreement and started service in Argentina shortly after contracting. Such ownership structures could significantly shorten the route to market for upstream developments.

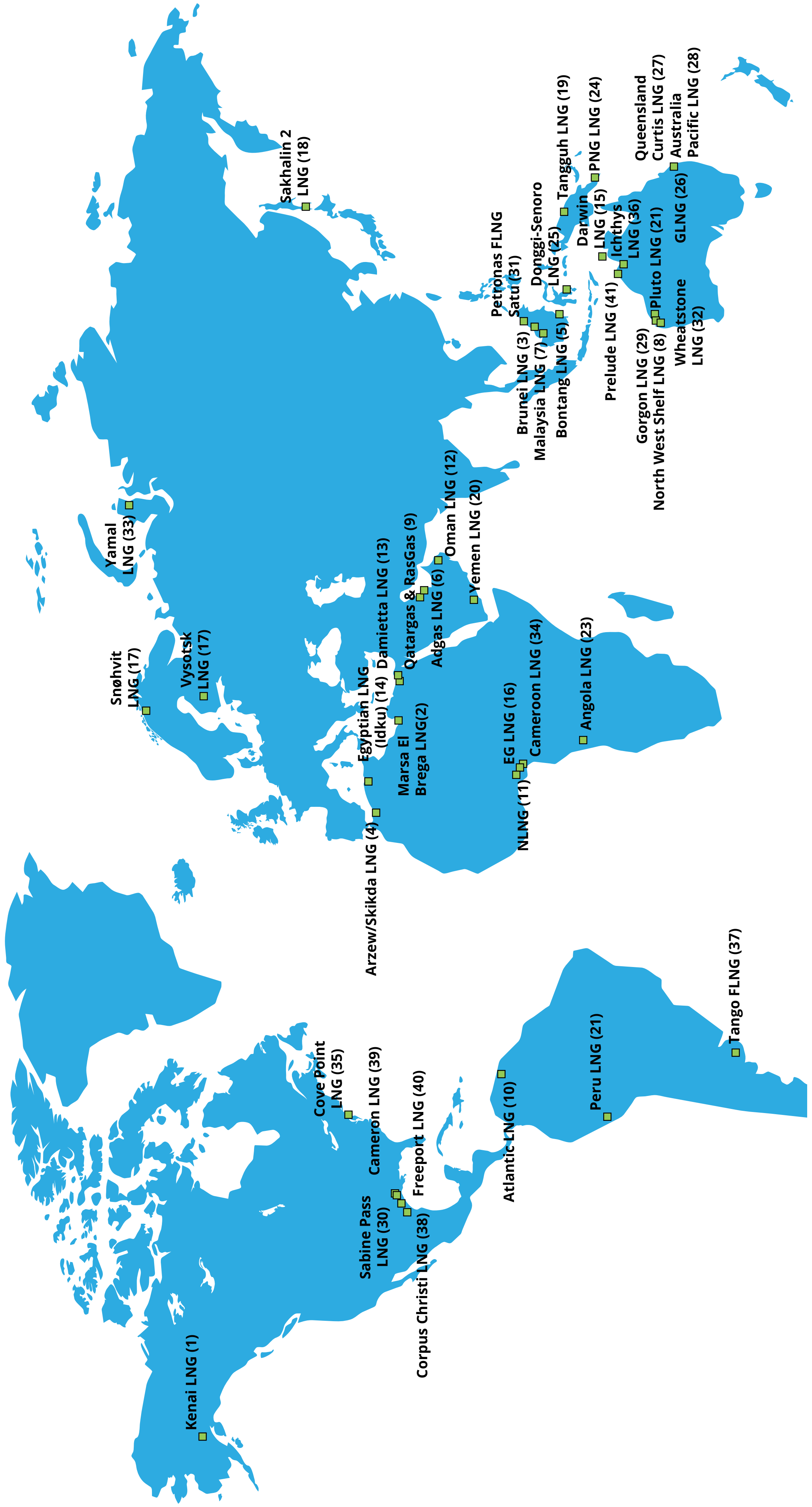


Figure 4.11: Global Liquefaction Plants, February 2020

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

4.6. RISKS TO PROJECT DEVELOPMENT

Oversupplied LNG Market

Deterring Project Developers

In addition to the traditional risks liquefaction project developers face, the currently oversupplied LNG market is deterring many project developers. This LNG "glut" is largely driven by the rapid growth in LNG supplies, coming mostly from Australia, USA and Russia over the past few years. Demand for LNG is not responding in tandem, to enable a balanced market at an acceptable price to all, resulting in a current lower price environment.

Essential to reaching FID on an LNG project is the treatment of risk; assessing and quantifying its likelihood and potential severity. LNG projects have long business development cycles, which may span a decade (or much more) from upstream resource discovery through to FID, followed by the 4+ year EPC phase, involving many teams from different partners and contractors. This increases the complexity of the overall task and adds many risk components.

Market Outlook

An oversupplied market is challenging for new LNG export projects, and developers need to brace themselves for a continued glut as further production is added, outpacing global demand potentially for another two years. This will mean continued depressed prices. This is then likely followed by a period of recovery, with renewed uncertainty around the middle of the decade. This outlook is expected to set the tone among the projects that are actively under development and have yet to reach final investment decisions (FID), and was anticipated by many reputable forecasters. How many will go forward, versus potential up- and downsides to forecasted demand, is key to determining exactly when the market balances. Projects typically have a lead time of ~5 years between FID and commercial operations, and thus pre-FID developers will have to think through this uncertainty from the mid-2020s onward now.

While it is relatively easy to see what's coming on the supply side, given the long lead times for liquefaction projects, predicting demand is much more difficult. The significant number of final investment decisions (FIDs) which have been taken in 2019 imply that developers believe the current glut in the market is expected to fade after 2020, and their volumes will find markets.

Supply Wave

The 42.5 MTPA of new liquefaction capacity added in 2019, is expected to prolong excess supply in the global LNG market into the mid to late 2020s, well beyond the 2022/2023 forecast of just a year ago. Adding to that potential surplus is the Qatar North Field LNG Expansion (the world's most cost-competitive source of LNG) which will add a further 49 MTPA of supply, to come onstream between 2024 and 2027, which would extend the expected period of oversupply by a couple of years.

However, the current wave of additional supply and persistent weak global prices are challenging new projects seeking final investment decisions and the current slump in LNG prices could lead to project FIDs being delayed. There are more than a dozen liquefaction plants scheduled for a final investment decision (FID) in 2020 and if buyers remain hesitant to sign long term agreements, some of these will have to be deferred or cancelled.

There is a significant competitive advantage for LNG project developers in geographic locations with access to low cost resources, proximity to high volume and/or high value markets, and opportunity to achieve competitive liquefaction project costs. Financing multi-billion dollar projects involves equity investments, shareholder and commercial loans or, where applicable, project finance with the involvement of export credit agencies and the World Bank providing political risk insurance for markets lacking sufficient regulatory and mega-project track record. In such a complex and challenging business environment, expansion of existing projects with a proven track record and strong balance sheet also have a significant competitive advantage.

There was record progress in 2019, with liquefaction project FIDs for: Arctic LNG 2, Mozambique LNG, Golden Pass, Sabine Pass T6, Nigeria LNG Train 7 and Calcasieu Pass.

Highly anticipated LNG FIDs in 2020 include Rovuma LNG in Mozambique and the North Field Expansion trains in Qatar.

Contracting Trends

Many projects are seeking to reach an FID in 2020 to come online in the mid-2020s when some market participants expect material new LNG supply will be needed. However, most proposals that have not reached FID remain (partially) 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 continue the upward trend seen in 2018 and 2019, particularly if suppliers show a willingness and ability to invest without contracts.

New Markets

Over the past decade, the market for LNG has expanded dramatically, opening up a space that was previously limited to a small number of big importers. This expansion has been assisted by the availability of FSRUs, which simplify the process for a market to become an importer. However, of the many new importing markets that have recently joined the LNG market, most stop at a relatively small import volume, and some even reduce their imports over time. Only a few markets have kept growing, and fewer still have become large markets. Clearly LNG has been remarkably successful in penetrating new markets, but has had a harder time converting these markets into big consumers. Just as often, markets hit a plateau and remain at that import level, or might even turn to alternatives that reduce their LNG needs.

The next wave of LNG demand growth expected from Asia's emerging economies is far from assured, raising questions about the speed with which supply from new projects can be absorbed by the market in the coming decade.

4.7. UPDATE ON NEW LIQUEFACTION PLAYS

New Liquefaction Capacity

Proposed Around the World

The pickup 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 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.

Progress was achieved on both commercial and regulatory fronts in 2019 despite an investment hiatus prior to this FID wave. Several regions around the world have proposed large new liquefaction capacity based on significant gas resources. Projects are examining ways to improve their competitiveness, though political and geopolitical risks remain in some regions, which can extend development timelines.

Middle East

During 2019, Qatar Petroleum increased plans for expansion of its LNG production facilities with the addition of 2 more trains (to the previously announced 4 train expansion) and now expects to produce 126 MTPA from these 6 new trains by 2027. The new LNG mega-trains are scheduled to come online at intervals of three to six months after the first starts-up in 2024. This expansion will raise Qatar's LNG production from the current 77 MTPA, an increase of about 64%. All 6 new trains will use the same 7.8 MTPA Air Products AP-X process as the existing operating trains.

In Oman, a planned debottlenecking project will enable Oman LNG to increase production from its 3 train plant at Qalhat from 10.4 MTPA to 11.5 MTPA by 2021. According to earlier media reports, the proposed debottlenecking exercise coupled with the upgrades to the refrigeration compressors, could potentially boost output by 1.5 MTPA.

United States

The LNG boom continues and now the USA has six export facilities online with 15 trains in service. The US accounted for over half of all new global liquefaction capacity added in 2019, and is now the world's third largest LNG seller, behind leader Australia and Qatar – and on track to become the biggest global LNG exporter by 2024, overtaking Australia and Qatar.

Supported by abundant supplies of shale gas and growing liquefaction capacity, the USA's LNG export has experienced a meteoric rise that started with the first commercial LNG cargo shipped from Cheniere's Sabine Pass in Louisiana in 2016.

The six operating LNG export facilities (Sabine Pass, Freeport LNG and Corpus Christi LNG in Texas, Cove Point LNG in Maryland, Cameron LNG in Louisiana and Elba Island in Georgia) are all adding production capacity over the next two years.

Cameron LNG, Freeport LNG and Elba Island all shipped their first cargoes in 2019. The innovative Elba Island facility (which involves adding 10 small-scale 0.25MTPA modular units to the existing import terminal) is reported as starting-up its small scale trains progressively through 2020. In 2020 the remaining trains at Sabine Pass, Freeport, Cameron and Elba Island will be placed into service, and a third train at Corpus Christi should be brought online in 2021. Numerous additional projects are looking to ride the second US wave of gas exports in another round of development.

In terms of projects sanctioned in 2019:

- Sabine Pass T6 — Cheniere — After reaching FID on Train 6 in June, Cheniere advised that it expects the facility's additional capacity to enter service in 2023. In parallel, Cheniere noted it has increased the run-rate production guidance to 4.7 - 5.0 MTPA per train, based on the impact of production optimisation, maintenance optimisation, and debottlenecking projects at both the Sabine Pass and the Corpus Christi LNG projects.
- Calcasieu Pass — Venture Global — Site construction has been underway since February 2019, FID was taken in August 2019, and the project is expected to reach its Commercial Operations Date (COD) in 2022. The 10 MTPA facility is under construction at the intersection of the Calcasieu Ship Channel and the Gulf of Mexico. The Calcasieu Pass project is expected to cost $4.25 billion. The LNG facility includes nine 1.2MTPA liquefaction blocks, two 200,000 m^3 full containment LNG storage tanks and two ship-loading berths. The facility is electrically driven and will be powered by a 611MW combined cycle gas turbine power plant with an additional 25MW gas-fired turbine.
- Golden Pass — 70% Qatar Petroleum and 30% ExxonMobil — the $10+ billion project will have a capacity of 15.6 MTPA at the three train facility. Exports are expected to commence in 2025, with trains in service on a staggered schedule; Train 1 expected to be online no later than September 30, 2025, Train 2 by March 2026 and Train 3 by November 2026.

Other projects slated by their proponents for near term FID are:

- Corpus Christi Stage 3 — Cheniere — FID on the Corpus Christi Stage 3 project, scheduled for next year, is contingent on acquiring the essential financing arrangements and commercial support for the project. Stage 3 is being developed for up to seven midscale liquefaction trains with a total capacity of approximately 10 MTPA. The Stage 3 site is adjacent to the existing three liquefaction trains. Cheniere expects to make a positive FID on Stage 3 in 2020.
- Jordan Cove — Pembina — Jordan Cove LNG is a proposed 7.8 MMTPA LNG export facility to be located at the Port of Coos Bay, Oregon. The proposed facility includes five 1.5 MTPA trains and two 160,000 m3 LNG storage tanks. Jordan Cove would be the first natural gas export facility sited on the US West Coast.
- Freeport Train 4 — Freeport — Freeport LNG is developing a fourth natural gas liquefaction unit. This expansion will allow for the export of an additional 5.1 MTPA LNG, increasing the site's total export capability to 20.4 MTPA. The project will also include a fourth pre-treatment unit and will use electric motors with variable frequency drive for the cooling and liquefaction compression power. Train 4 will be constructed adjacent to the first three trains. Train 3 is nearly complete with commercial operations expected in May 2020. The Train 4 EPCC will be undertaken on a fixed price contract with KBR (whereas Trains 1 to 3 were carried out by CB&I, Chiyoda and Zachry). Final Investment Decision for Freeport LNG's Train 4 is targeted for the first quarter of 2020.
- Driftwood — Tellurian — The facility will consist of five LNG plants, with each plant comprised of one gas pre-treatment unit and four liquefaction units. Each of the 20 liquefaction units will produce up to 1.38 MTPA of LNG, using Chart Industries' Integrated Pre-cooled Single Mixed Refrigerant (IPSMR®) liquefaction technology. The LNG facility will use 20 GE refrigeration compressors driven by BHGE LM6000PF+ drivers. The LNG will be stored in three 235,000 m3 LNG storage tanks. Bechtel signed four LSTK turnkey agreements, with each agreement covering one of the four phases.
- Magnolia — LNG Ltd — Magnolia LNG is a mid-scale LNG export project, with four trains, each with a plant capacity of 2 MTPA of LNG for a total of up to 8 MTPA to be built on the Industrial Canal near Lake Charles. The patented OSMR® liquefaction uses a combined heat and power plant and a steam-driven pre-cooling refrigeration system.
- Lake Charles — Shell and Energy Transfer — This brownfield export facility would include three liquefaction trains with a combined capacity of 16.45 MTPA.
- Port Arthur — Sempra — The initial phase of this project is expected to include two liquefaction trains, up to three LNG storage tanks and associated facilities to enable the export of approximately 11 MTPA of LNG.
- Rio Grande — Next Decade — Next Decade are working towards FID by the end of the first quarter of 2020 and commencing commercial operations in 2023. The project would have a total capacity of 27 MTPA with 4 x 180,000 m3 full-containment LNG storage tanks.
- Plaquemines — Venture Global — This project includes 18 liquefaction blocks developed in two phases, with each block having a nameplate capacity of 1.2 MTPA and consisting of two modular mid-scale trains of 0.626 MTPA Single Mixed Refrigerant liquefaction units and ancillary support facilities. It will also contain four 200,000 m3 storage tanks. The facility will use a combined-cycle gas-turbine (CCGT) power plant with a generating capacity of approximately 611 megawatts (MW) plus an additional 25 MW gas-fired turbine for phase one.
- Brownsville — Annova — This 6.5 MTPA LNG export facility on the Port of Brownsville, Texas is scheduled to commence commercial operations in early 2025 from six liquefaction trains, each with a nameplate liquefaction capacity of 1 MTPA.
- Cameron Parish — Commonwealth — This is an 8.4 MTPA LNG liquefaction and export facility. The facility will have six 40,000 m3 modular storage tanks. Each of the facility's six liquefaction trains will be capable of producing 1.4 MTPA, and will be constructed using a modular approach.
- Alaska — Alaska Gasline Development Corporation (AGDC) - Outside the continental US, the proposed $43.4 billion 20 MTPA Alaska LNG project continues to work towards sanction. On June 28, 2019 FERC published its Draft Environmental Impact Statement (DEIS) for the project proposed by the Alaska Gasline Development Corporation (AGDC). The regulators issued a report that found it would provide economic benefits to the state but could hurt the environment.

Canada

LNG export is in Canada's interest, with clear financial and economic benefits. Canada has huge gas resources potentially available for export. The key question has always been whether their development could be done in a cost-effective manner to allow Canadian LNG to compete with emerging supplies from the rest of the world. As the world's fourth largest producer and fifth largest exporter of natural gas today, Canada was a vital supplier to the United States for decades.

In addition, the production technology that underpinned the US shale revolution quickly unlocked vast new gas reserves in Canada.

Roughly 20 Canadian LNG project proposals were active only five years ago, with investors attracted to the vast reserves and the variety of LNG business models available in Canada. Since that time, investor interest in Canadian projects has waned and to date only one project (the 14 MTPA Shell led LNG Canada project) has been sanctioned.

While most Canadian LNG developments remain uncertain, competing US projects (while having greater shipping distances to Asia if on the

Construction of LNG Plant in Yamal, Russia

US Gulf Coast (via the Panama Canal), have attracted a deluge of LNG investment. However, offsetting that shipping advantage is that Canada is less attractive in terms of feed gas transport cost. Unlike many other proponent regions, Canada's prolific gas basins are located hundreds of kilometres from the West Coast, and thus those projects will have higher capex to get feed gas from the wellheads to the potential liquefaction locations. Rather than a geographical LNG hub, where pipelines terminate at or near the point of liquefaction, Canadian LNG proponents have proposed development of relatively isolated projects on the West Coast that must plan and build expensive dedicated pipelines through mountainous routes.

There are many reasons in addition to feed gas cost aspects that explain why so many US LNG projects have proceeded, while Canadian projects have remained stagnant. These include indigenous land rights, greenfield versus brownfield construction, availability of labour at locations, environmental assessments and changes of Governments.

Since 2015 most of the proposed Canadian LNG export projects have either been cancelled, integrated into other projects, such as LNG Canada (e.g. the Petronas-led Pacific Northwest LNG and BG's Prince Rupert LNG), or remain active and awaiting FID:

- Woodfibre LNG (West, 2.1 MTPA): A smaller low-emission project that is reportedly close to FID
- Kitimat LNG — Chevron/Woodside- (West, 20 MTPA): This project was proposed to take FID in 2022–23 as a liquefaction facility at Bish Cove near Kitimat, with three LNG trains totalling 18 million tonnes per annum (6.0 MTPA/train), and was to be an all-electric plant powered by clean, renewable hydroelectricity from BC Hydro. However in late December 2019, Chevron announced plans to sell its 50% stake. The proposed Kitimat LNG Project was a 50/50 joint venture between Chevron and Woodside, who had previously announced that it was also seeking to sell a share in the project.
- Cedar LNG (West, 3–4 MTPA): Owned by Haisla First Nation; is just commencing environmental review.
- Goldboro LNG (East, 10 MTPA): Secured 5 MTPA commitment from Uniper in Germany; likelihood of FID is uncertain
- Energie Saguenay LNG (East, 10 MTPA): Strong headwind of ardent anti-fossil fuel activism in Quebec makes it unlikely this project will go forward

Mexico

An LNG export project, based on Sempra's Costa Azul LNG import facility, has been proposed for Mexico. Sempra has signed three equal volume HOAs for 20-year LNG sales-and-purchase agreements for the 2.4 MTPA export capacity of Phase 1 of the project located in Baja California, Mexico. Energia Costa Azul (ECA) LNG Phase 1 is a single-train liquefaction facility to be integrated into the existing LNG import terminal. ECA's existing facilities include one marine berth and breakwater, two LNG tanks of 160,000 m³ each, LNG vaporizers, nitrogen injection systems and pipeline inter-connections. The liquefaction project would add natural gas receipt, treatment and liquefaction capabilities and loading of LNG cargoes.

East Africa

Mozambique is expected to become one of the world's largest LNG exporters, with two major projects fully sanctioned (the Area 1 Mozambique LNG Project and the Area 4 ENI led Coral Sul LNG-FPSO ultra-deepwater project) and the third (the Area 4 Rovuma LNG Project) expecting to be sanctioned in 2020.

In September 2019, Total acquired Anadarko's 26.5% stake in the Area 1 Mozambique LNG Project from Occidental after Occidental acquired Anadarko. This makes Total the largest shareholder and operator of the project. Mozambique LNG is the market's first onshore LNG development and the project includes the construction of a two train liquefaction plant with a capacity of 12.9 MTPA. The Final Investment Decision (FID) on Mozambique LNG was announced in June 2019, and the project is expected to come into production by 2024.

An adjacent project, Area 4 Rovuma LNG led by Eni and ExxonMobil, will in the first phase consist of two liquefaction trains of 7.6 MTPA for total capacity of 15.2 MTPA. In October 2019 the project received a boost with the announced Initial Investment Decision of US$500 million for the project, enabling the project to advance shared midstream and upstream area project activities. FID on the project — expected to cost around $30 billion – is anticipated to be announced in the first half of 2020. The EPC contract for the onshore facilities was also awarded. ExxonMobil is leading construction and operation of the liquefaction trains and related onshore facilities for the project, while Eni will lead upstream developments and operations.

In early 2020, the Area 4 ENI led Coral Sul LNG-FPSO ultra-deepwater project reached a milestone with the launch of the hull in South Korea on 14 January 2020. This project is of similar capacity and complexity to Shell's Prelude LNG-FPSO.

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

West Africa

The Greater Tortue LNG-FPSO project straddling the Senegal and Mauritania border, continues at an accelerated pace. Based on experience gained from converting the Hilli LNGC into an FLNG vessel for the Cameroon Kribi development, the project will use the Golar Gimi LNGC for conversion by Keppel (who received full go ahead in 2019), enabling the FLNG vessel to begin producing cargoes in 2022. The Phase 1 FLNG facility is designed to provide 2.5 MTPA of LNG for global export as well as making gas available for domestic use in both Mauritania and Senegal. The project partners made the final investment decision (FID) for Phase 1 of the project in 2019, which will ultimately produce up to 10 MTPA of LNG and is due to come onstream in the first half of 2022. Phases 2 and 3 will expand capacity to deliver additional gas from an ultra-deepwater subsea system, tied back to mid-water gas processing platforms. The gas will then be transferred to pre-treatment and offshore LNG facilities located at the established Phase 1 hub. A final investment decision (FID) for Phase 2 and Phase 3 of the development will reportedly take place in the second half of 2020. The phases will include fixed platforms with platform-mounted LNG modules which will be linked to the infrastructure installed during the first phase of the development. Each phase will increase production by 3.7 MTPA. First gas from Phase 2 is anticipated to be achieved in 2024 and Phase 3 will start-up in 2025. Linde has been selected as LNG technology licensor for Phases 2 and 3, based on its MFC2 liquefaction technology.

In December 2019 Nigeria LNG made the FID for its Train 7 project, which will increase the NLNG facility's production capacity to 30 MTPA, with first LNG rundown expected in 2024. The expansion project will produce an additional 7.6 MTPA with additional feed gas treatment facilities (producing 4.2 MTPA) and additional (producing 3.4 MTPA) processing of treated gas from existing pre-treatment facilities.

Russia

The three key players in the Russian gas industry (Gazprom, Rosneft, and Novatek) each developed a strategy that was compatible with its own asset base and previous experience, and as a result three competing approaches to LNG developments in Russia have emerged.

The 16.5 MTPA Yamal LNG project commissioned its Train 3 in 2019. Yamal Train 4 is an additional small-scale 0.9 MTPA train (using a Russian designed Arctic Cascade process) with a start-up planned for early 2020.

In September 2019, Novatek's Arctic LNG 2 project was sanctioned. The LNG plant will consist of three (3) liquefaction trains with overall production capacity of 19.8 MTPA. The start-up of LNG T1 is scheduled for 2023, with LNG T2 and T3 to be started in 2024 and 2026 respectively. Arctic LNG 2 employs an innovative concept using gravity-based structures (GBS) and provides for localising the majority of fabrication in Russia (whereas Yamal imported fabricated modules). The GBS construction and installation of LNG modules will be performed at a new casting basin located in the Murmansk Region. A consortium of TechnipFMC, Saipem and NIPIGAS was awarded the EPC contract, with the GBSs be built by the Russian company. The facility will use Linde's LNG liquefaction technology. The project consists of three GBSs, which are artificial islands to be installed in shallow water. An example of how this concept is constructed within a 'casting basin', floated out, towed to location and installed, is the Adriatic LNG offloading, storage, and re-gasification terminal (albeit the Arctic 2 GBSs are much larger and complex, and support processing liquefaction facilities). The GBS LNG concept requires modularisation of the process units for integration on the GBS top slab at construction yard. The GBSs will be made of highly reinforced and prestressed concrete. Each GBS will house membrane LNG storage tanks and on top they will support the processing facilities, utilities and living quarters etc. Construction and integration of the GBSs and topsides modules will take place in the Murmansk yard. After commissioning in the construction yard, the GBSs will be floated out and towed to the Arctic LNG location and ballasted down ono the seabed.

In late 2018, Gazprom and Shell inked a framework agreement on the technical concept for Baltic LNG, with Shell's proprietary large-scale liquefaction technology being seen as a crucial factor for the success of the project. Gazprom's latest concept for Baltic LNG provides for the full integration of the liquefaction plant for the production and shipping of 13 MTPA of LNG. In 2019 it became clear that Shell would no longer participate in the project, and Gazprom reported that it is now considering the use of Linde's technology. Gazprom said it is expecting to put the first train of the complex into operation in the second half of 2023 and the second train in late 2024.

ExxonMobil with its partner Rosneft is reportedly moving forward with the Far East LNG project, for a single train plant with a planned capacity of more than 6.2 MTPA. The facility would use gas from the Sakhalin-1 venture as the source. The project would help monetise the gas reserves of the Sakhalin-1 PSA, as that gas has to date been re-injected to maintain reservoir pressure and assist in oil recovery. The partners were considering whether to build their own LNG plant or to sell gas to Gazprom's existing Sakhalin-2 plant, which has been considering a third train expansion, but the parties failed to agree on the sales price. Sakhalin-1 plans to build its own LNG plant at the De Kastri port in Russia's Khabarovsk region.

The planned third train expansion of the Sakhalin-2 LNG plant would have increased the plant's capacity by 50%, from 9.6 MTPA to 15.0 MTPA, however expansion plans have been put on hold. The main reasons for the hold-up are the lack of gas resources and international sanctions placed on Russian individuals and entities.

Australia

By the end of 2019, Australia's liquefaction capacity, with 21 LNG trains operational, was 87.6 MTPA nameplate capacity.

Other than Scarborough, the LNG related projects underway in Australia (for Browse and Barossa) are predominately feed gas "backfill" projects, involving new offshore field development for feed gas supply into existing LNG plants.

Woodside plans to monetise the Scarborough development through an expansion of the existing Pluto LNG facility, via a second train. Woodside awarded a FEED contract to Bechtel for Pluto Train 2, which will utilise the ConocoPhillips Optimized Cascade process. The FEED contract includes the option to construct a 5 MTPA train, subject to a positive FID planned for 2020, with first LNG scheduled for 2024.

Woodside also proposes to build a 5 km, 30 inch interconnector pipeline to transport wet gas between the expanded Pluto LNG facility and the North West Shelf (NWS) Karratha Gas Plant (KGP), to fill short-term spare capacity at the latter.

The Browse development is to backfill the existing NWS LNG trains, with an FID slated for 2021. Woodside is operator of the Browse fields and the development concept includes a 900 km pipeline to the existing North West Shelf infrastructure.

The 2019 acquisition by Santos of ConocoPhillips' northern Australia business with operating interests in Darwin LNG and Bayu-Undan advances Santos' goal of taking Barossa to FID by early 2020, with first LNG using Barossa gas expected in 2024. With the Bayu-Undan field maturing, the joint venture has been evaluating alternate supply sources to extend the operating life of Darwin LNG. Santos was a founding partner with ConocoPhillips in Darwin LNG, which has been operating since 2006.

Papua New Guinea

In 2019 PNG LNG achieved a record gross production of 8.5 MT, 2% higher than the previous record reached in 2017, from the existing two train facility.

The expansion of the PNG LNG project is planned to be a three-train 8.1 MTPA expansion (each train 2.7 MTPA) on the existing PNG LNG

Nigeria LNG Terminal, Courtesy of Shell site, sharing infrastructure with PNG LNG. The new LNG trains are underpinned by gas from P'nyang for one train (for the ExxonMobil lead grouping) and two trains based on gas from Elk-Antelope (for the Total led group). Coming to an agreement on a new production sharing agreement that meets the needs of all stakeholders has taken time, with the FEED entry timeline impacted. Total and ExxonMobil had both announced an intended FID for their respective projects in 2019, and have now indicated this will be delayed by 6 months to 1 year as negotiations have not concluded.

Key commercial agreements and pre-FEED activities for the three-train integrated development are all largely complete and subject to the completion of the P'nyang Gas Agreement. The deal with the government for the P'nyang gas field which is being negotiated by PNG LNG venture operator ExxonMobil will set the fiscal terms for the development of P'nyang, an important part of a planned three train expansion.

Eastern Mediterranean

Egypt was the world's eighth biggest LNG exporter in 2009 with three trains operating at two facilities. However, population growth and energy subsidies fuelled domestic consumption, while a relatively unattractive investment regime deterred exploration investment. As a result, gas production fell, there were gas shortages and the government prioritised domestic needs over gas exports, with the result that the government required gas to be diverted to the domestic market. As a result the market stopped LNG exports and began importing LNG via two floating storage and regasification units (FSRUs) in 2014. Egypt only became self-sufficient in natural gas again in late 2018 and the Egyptian LNG Idku facility has been exporting at reduced rates since 2016. 2020 appears to signal a potential increase in LNG exports from Egypt, with Idku expected to reach its full capacity by the end of 2019, and the Damietta facility is also expected to begin exporting LNG again, although disputes between the Damietta shareholders and the Egyptian government relating to the earlier curtailment of gas supply for export have not been fully resolved.

Delek and Noble, partners in the Leviathan field off Israel's Mediterranean coast, are considering LNG export options (including potentially leasing a newbuild LNG-FPSO from either Golar or Exmar).

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 delayed by a year and is expected to begin in the third quarter of 2021 versus an initial target of the third quarter of 2020.

In 2019, the Abadi LNG Project (Inpex 65%, Shell 35%) received approval from Indonesian authorities for a revised plan of development (PoD) for the project. The Masela Block is located 150 km offshore Saumlaki in Maluku Province. The project has a proposed capacity of 9.5 MTPA. The project's development concept has been changed from a floating LNG scheme to an onshore LNG scheme, with a potential start-up in the latter half of the 2020s.

The Sengkang LNG facility, which has been delayed for more than 12 years, primarily due to unresolved issues with Indonesian authorities, continues to remain on hold. Construction of the LNG terminal is reportedly 80% complete and the construction continues 'at a modest pace'. EWC is waiting on a number of agreements to be finalised before proceeding to complete the project.

Malaysia

Petronas' PFLNG1 Satu, the world's first operational LNG-FPSO, reached its final stages of start up with the introduction of gas from the Kanowit gas field in November 2016. In 2019, it made a significant achievement when it was relocated to the Kebabangan field, offshore Sabah.

Construction of Petronas' second floating LNG facility (PFLNG2 Dua) is complete and this second LNG-FPSO has been installed on the Murphy-operated Rotan field 240 kilometres offshore Sabah. PFLNG2 Dua will boost Malaysia's total LNG production capacity by another 1.5 MTPA. The LNG-FPSO is designed to extract gas from deepwater reservoirs at depths up to 1,300 metres. PFLNG2 set sail from South Korea in its maiden voyage to the Rotan Gas Field, located offshore Sabah, Malaysia in February 2020 and Petronas advised that it's Ready-for-Start-Up date was earmarked for mid-2020.

Shell's Terminal at Hazira - Courtesy of Shell

4.8. REFRIGERATION COMPRESSOR DRIVER DEVELOPMENTS

Four Types of Drivers for Refrigeration Compression

Utilised by LNG Operators

When it comes to natural gas liquefaction, selecting the right machinery to drive refrigeration compressors is critical. There are generally four types of drivers which have been utilised by LNG operators, each of which possesses characteristics that make it more or less appropriate depending on the application. They are:

Steam Turbines — In the early years of the LNG industry, steam turbines were the primary mechanical drivers for the refrigerant compressors. Although steam turbines offer high reliability, their low efficiency and substantial requirements with regards to weight and footprint have generally made them obsolete.

Industrial Gas Turbines — While the first gas turbine drivers (GE Frame 5s) were deployed in an LNG export plant in 1969 at the Kenai, Alaska plant, steam turbine drivers continued as drivers of choice, until the Arun LNG plant came into operation in 1978. Since then, over the past three decades, industrial gas turbines (GE Frame 5, 6 and 7) have been the mainstay of direct drive LNG applications. They possess high thermal efficiency (up to 39%) and are available in a broad range of sizes, which makes them suitable for virtually any train capacity. One drawback of industrial gas turbines is that they cannot be started from settle-out condition and in many cases require the use of starter motors. With high fuel consumption, they are often associated with high emissions.

Today, heavy-duty gas turbines are the most common mechanical driver selected for LNG plants with ISO ratings extending from 30 MW to 130 MW. Initially these plants use water cooling along with gas turbine drivers, with the first use of gas turbines with air-cooled heat exchangers being in the Woodside NWS Project (with Frame 5 drivers). The next move was to larger Frame 6 gas turbines, followed by combinations of Frame 6 and 7, and on to the current "standard" of dual Frame 7s in various compressor/driver arrangements.

Aeroderivative Gas Turbines — Aeroderivative gas turbines offer a higher thermal efficiency than industrial gas turbines. This leads to less fuel consumption and fewer emissions. They are also smaller and lighter, making them a particularly popular solution for offshore LNG applications. Advantageously, they can operate at variable speeds. They reach energy efficiencies between 41-44%, about 25% better than industrial turbines.

Electric Motors — Electric motors have become an increasingly popular option for natural gas liquefaction in recent years. In addition to eliminating issues associated with air temperature variation, which can be a particular concern with gas turbines, electric motors offer high reliability and are environmentally friendly. Because these systems are mechanically less complex, they tend to have somewhat higher operational availability. However, e-drives remain a new technology with less of a proven track record, and as cutting-edge technologies go, they are somewhat more expensive.

There are several options with eLNG:

Onsite power generation — This technology is currently used in Statoil's 4.1 MTPA Snøhvit plant in Norway. Typically the power plant is "inside the fence" and is a combined-cycle gas turbine (CCGT) plant. In such a plant, a gas turbine extracts mechanical energy from burning natural gas, and the waste heat from the burned gas is transferred through a heat exchanger to a secondary steam cycle that powers a second turbine. The thermal efficiency of CCGT plants is very high, reaching 60% rather than the 40% of conventional single-cycle gas plants.

Offsite purchased power- This technology is currently used in the electric-drive plant built in Freeport in Texas with three trains of 4.4 MTPA capacity, equipped with six 75 MW compressors. Grid electricity is supplied from "outside the fence".

Recent developments

Steam turbines

The single recent LNG export facility to utilise steam turbines is the Shell Prelude LNG-FPSO. The selection of steam turbines for the power generation and refrigerant compressor drivers was subject to extensive study. Compared to a traditional onshore facility, a remotely located floating facility has unique challenges which affect equipment selection. Whilst efficiency is an important consideration, reliability is more critical as the floating facility will be permanently moored offshore for ~25 years and will have limited space and capacity on board for undertaking major maintenance or repair campaigns. Steam turbines, whilst not as energy efficient as say drive aeroderivative gas turbines, were selected because they offer proven high reliability in a marine setting, simpler operations and maintenance, reduced rotating equipment count (reduced complexity), use of low pressure fuel gas and they avoid the use of fired equipment in the liquefaction modules.

Electric motors (eLNG)

Examples of recent LNG export plants using or proposing to use electric motor drives for their refrigeration compressors are:

- The 3 train (each train 5.1 MTPA) Freeport, Texas LNG export plant uses 3 x 75Mw electric motor drives for each train, with all the electricity purchased from the grid. This required an $80mn to upgrade the coastal Texas transmission grid to supply 656 MW of electricity. Using electric motor-driven technology has enabled Freeport to comply with strict local emissions standards and support their ambitious production and export targets. eLNG also means increased plant efficiency and expected availability.
- The 2.1MTPA single train Woodfibre, Canada LNG project will utilise electric drive turbines that will significantly reduce the total greenhouse gas (GHG) emissions of the LNG project, especially when the turbines are powered by renewable clean electricity.
- The multi small-scale train Calcasieu Pass LNG, Louisiana project is based on mid-scale liquefaction technology, with 18 mid-scale

modular trains driven by electric motors, consisting of nine blocks of two electrically driven 0.626 MTPA trains in each block. An on-site 611 MW combined cycle gas turbine power plant will produce the power required to drive the electric motors of the liquefiers. The "5 on 2" gas turbine to steam turbine configuration will allow for significant flexibility for maintenance or down time, allowing the facility to have extremely high availability for production. There will also be one aeroderivative gas turbine for startup and peaking needs.

Industrial GTs

In addition to the use of new compressor drivers (aeroderivatives and electric motors), new train configurations have been developed to improve availability.

One such innovative refrigerant train configuration is comprised of two identical parallel 50% APCI C3-MR liquefaction process strings. While parallel refrigeration machines have been in use for decades (primarily for the Phillips Optimised Cascade process which utilises parallel methane, ethylene and propane variable speed compressors), the Air Products licensed C3/MR LNG process plants have until recently used 100% compressor strings with the propane (C3) precooling circuit and the HP mixed refrigerant (MR) circuit driven by one Frame 7 and both the LP/MP mix refrigerant (MR) circuits driven by the other Frame 7 (the Split MR arrangement).

While such 50% parallel compressor string arrangements increase the number of compressor casings, an important benefit is the ability to seamlessly shift power between precooling and liquefaction compression services. This flexibility is particularly useful in climates with wide ambient temperature variations that result in large swings in the required precooling duty, as it allows for increased utilisation of the overall available power installed.

Examples of recent LNG export plants using 2 x 50% compressors strings are:

- The Cove Point and Yamal LNG facilities (each train 5.25 to 5.5 MTPA) both use the APCI AP-C3MR process with each train having 2 x 50% parallel strings with the propane and mixed refrigerant compressor casings on same shaft, each string driven by a BHGE Frame 7EA driver and a 20Mw starter/helper per string. Each of the two strings include propane, LP MR, and MP/HP MR compressors; with a Frame 7EA gas turbine and helper motor drivers located at opposite ends. The plants can operate at reduced capacity with only one string online, which increases the overall plant on-stream time and reduces the potential for flaring incidents.
- Other examples of recent LNG export plants using less common compressor strings arrangements are:
- The 2 train Total operated Mozambique LNG (each train 6.44 MTPA) plant will use 3 x BHGE Frame 7 EA drivers.
- While all other Bechtel designed plants utilising the ConocoPhillips Optimized Cascade liquefaction technology have either Frame 5, LM2500 or LM6000 gas turbine compressor drivers, the 5.2 MTPA Angola LNG plant uses 2 x Frame 6B + 2 x Frame 7EA industrial gas turbines for its refrigeration train, with its propane and ethylene services on the same shaft, unlike all other ConocoPhillips Optimized Cascade trains.

Aeroderivative GT

Aeroderivative gas turbines are two-shaft machines providing operating flexibility, with excellent starting torque which eliminate external starter/helper motors.

The initial LNG plants to use aeroderivative drivers were all ConocoPhillips Process plants designed by Bechtel, with the Darwin LNG facility (which started operations in mid-2006) being the first. Since then there has been a significant growth in the application of these engines for LNG mechanical drive, driven by the need to reduce greenhouse gas emissions and fuel auto-consumption.

The first Air Products process plant to use aeroderivative drivers was the PNG LNG plant, which started up in 2014.

Aeroderivative GTs are affected by heat more than industrial GTs, hence the use of TIAC (turbine inlet air chilling), which minimises seasonal production swings and increases annual LNG production capacity. While evaporative inlet air cooling had been used for Darwin LNG, chilling facilities were used for the first time at Curtis Island, Australia to successfully implement inlet air chilling, which cools the air to a constant temperature prior to entering the gas turbine. This element increases LNG production in high ambient conditions and effectively helps to maintain consistent annual LNG production. The combination of aeroderivative gas turbines and inlet air chilling have enhanced LNG production and increased efficiency to a new industry level.

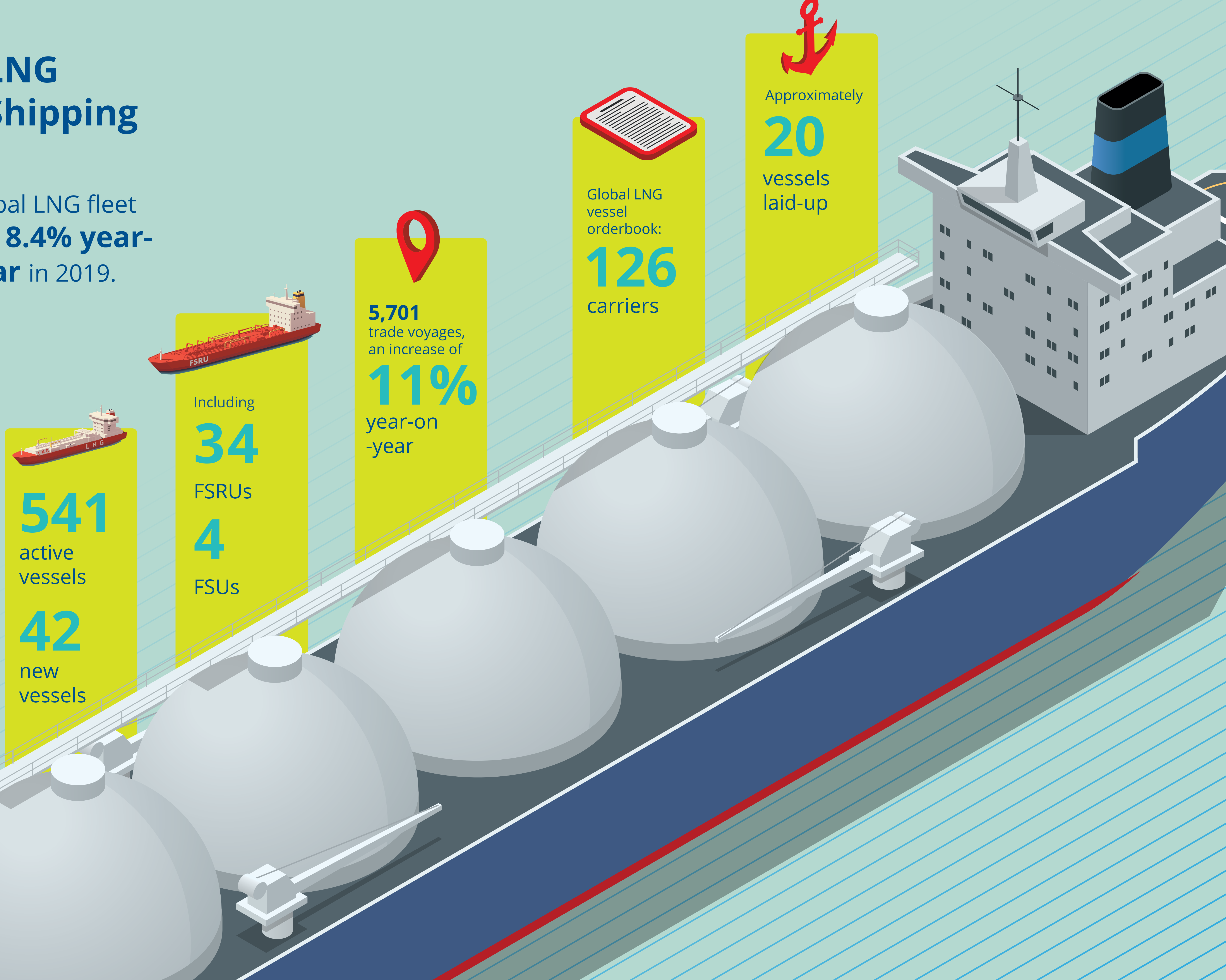
To date all aeroderivative gas turbine compressor drivers used in LNG liquefaction service have been GE's LM2500+G4 or the LM6000 PF. More recently, other GE and non-GE aeroderivatives are being utilised, and examples of recent or upcoming LNG liquefaction facilities using aeroderivatives include:

- 15 trains at various projects (Sabine Pass — 6 trains, QCLNG — 2 trains, GLNG — 2 trains, APLNG — 2 trains and Corpus Christi — 3 trains), though being near identical process schemes, the quoted nominal plant capacities range from 3.9 MTPA per train to 4.5 MTPA. These trains all use 6 x LM2500+G4 aeroderivative GT compressor drivers per train. In addition, the Darwin and Sabine Pass trains use inlet air evaporative cooling while QCLNG, GLNG, APLNG and Corpus Christi use inlet air mechanical chilling.
- The two train Wheatstone (also designed and installed by Bechtel) uses aeroderivative GT drivers (6 x LM6000PF) for 4.45 MTPA per train and uses inlet air evaporative cooling.
- The PNG LNG project (first APCI process to use aeroderivatives) uses 5 x GE LM2500+G4 (each train 3.45 MTPA).
- The two train LNG Canada project, which uses the Shell C3MR/DMR process, is to use 2 x BHGE LMS100-PB rated at 105Mw (each train 7 MTPA). These high efficiency gas turbines are the largest aeroderivatives available with a free power turbine, ideally positioning it for large LNG applications.
- The two train Lake Charles LNG project will use 4 x Siemens SGT-A65 (Trent 60) rated at 66Mw (each train 5.48 MTPA).
- The three train Arctic-2 LNG project in Russia will use the Linde MFC4 process with each train using 4 x BHGE LM9000 GTs rated at 55Mw (each train 6.6MTPA)
- The two train Rovuma LNG Project packages in Mozambique will use Mitsubishi Heavy Industries H-100 gas turbines and compressors. These are dual-shaft, 120 megawatt H-100 gas turbines. The H-100 is the world's largest dual-shaft heavy duty type gas turbine which offers high-efficiency, high-reliability and low-maintenance. The H-100 gas turbine's high availability, robust and simple industrial design requiring no external helper motor or intercooler, contributes to footprint and space savings. The project plans to utilise the Air Products AP-X® process and the project plan is for two liquefied natural gas trains, with each train expected to produce at least 7.6 MTPA.
- Petronas' PFLNG1 (1.2 MTPA) LNG-FPSO uses four PGT25+G4 gas turbine generator systems, two PGT25+G4 gas turbine driven compressor units and two electric motor driven centrifugal compressors for two AP-N nitrogen trains. Their PFLNG2 LNG-FPSO (1.5MTPA) uses two LM6000-PF aeroderivative gas turbines in mechanical-drive mode for the two AP-N nitrogen trains.
- Golar's LNG-FPSO vessel, Hilli Episeyo, was completed in 2018 and is currently in commercial operation offshore Cameroon. Each of the four B&V PRICO trains consists of a PGT25+G4 aeroderivative gas turbine driving a GE centrifugal compressor.

LNG Plant in Sakhalin Island, Russia

5 LNG Shipping

The global LNG fleet grew by **8.4% year-on-year** in 2019.



5.0 LNG Shipping

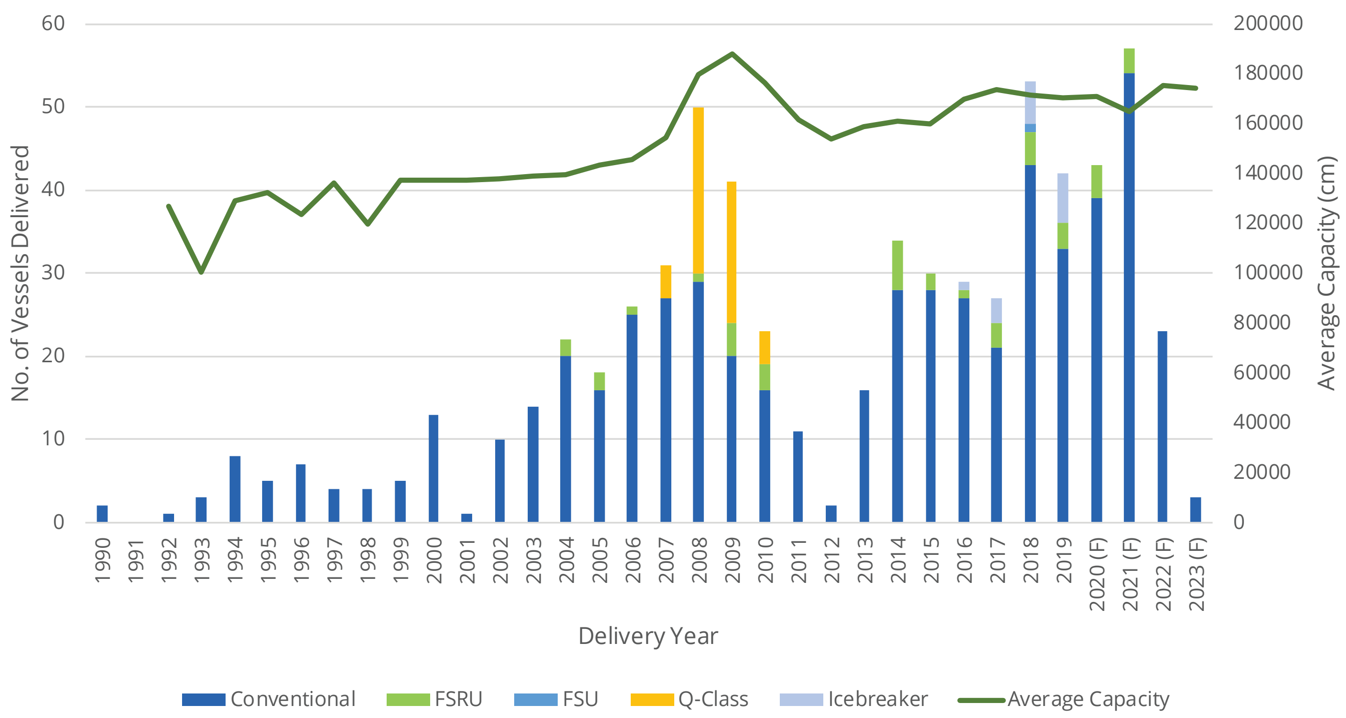
The global LNG fleet[1] at the end of 2019 consisted of 541[2] active vessels, including 34 Floating Storage Regasification Units (FSRUs) and four Floating Storage Units (FSUs). Overall, the global LNG fleet grew by 8.4% year-on-year (YoY) in 2019, with a total addition of 42 new vessels, of which three were FSRUs. By comparison, the annual growth of LNG trade in 2019 stands at 13%[3], showing a good balance between growth in the LNG shipping market and LNG trade.

Oizmendi Multi-Product Bunker Delivery Vessel - Courtesy of Itsas Gas Bunker Supply S.L.

[1] Only LNG carriers with capacity of 30,000cm and greater were included as part of the global fleet and orderbook and analysed for this report.
[2] This figure refers to the number of active vessels, excluding laid-up vessels
[3] GIIGNL

5.1. OVERVIEW

Figure 5.1: Global Active LNG Fleet and Orderbook by Delivery Year and Average Capacity



Source: Rystad Energy

LNG Newbuild Deliveries

Expecting Continued Growth

The LNG shipping market has developed rapidly since the early 2000s, following a general upward trend during the previous decade. The global financial crisis in 2008 resulted in a slowdown in orders, with only one newbuild LNG carrier ordered in 2009. This resulted in a short decline in deliveries until 2013, but the market has since picked up again, with recent years exceeding previous yearly deliveries. As seen in the chart above, LNG newbuild deliveries are still growing and this is expected to continue into the next few years[4].

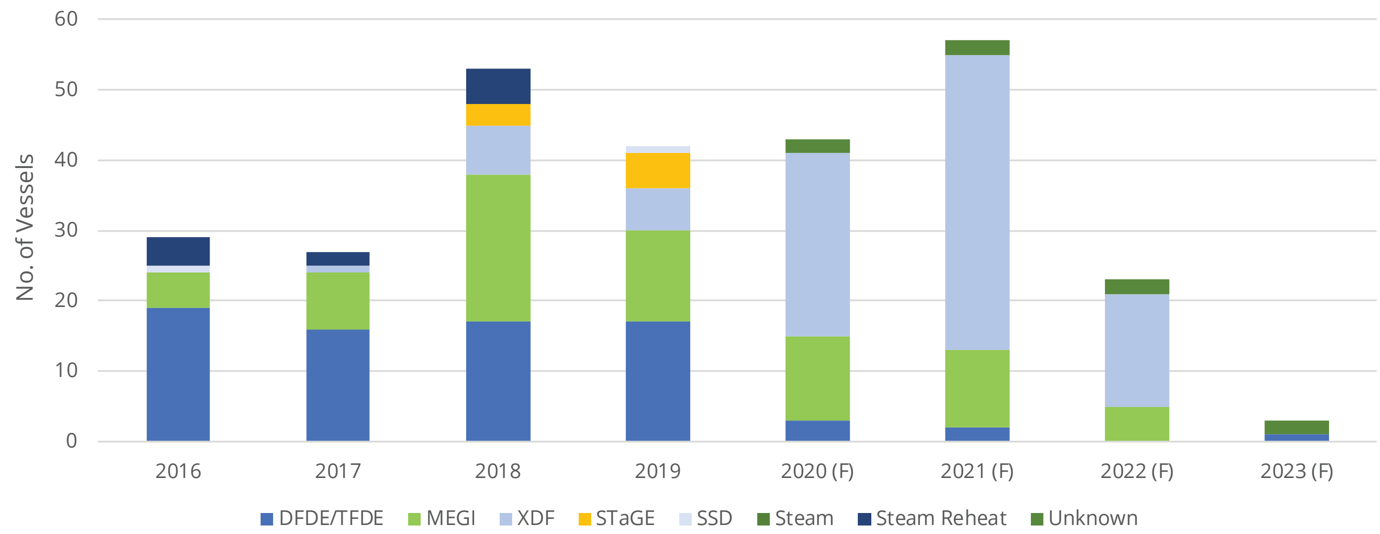
Following a trend established over the past several years, 86% of the newbuilds delivered in 2019 were between 170,000 cm and 180,000 cm in size, averaging about 170,000 cm. Vessels of this size remain within the limits of the new Panama Canal expansion transit while maximising economies of scale. Although larger vessels have become more common over time, this is a departure from the trend seen in the 2007-2010 period, when 45 Qatari Q-Class newbuilds exceeded 200,000 cm in capacity.

The fleet is relatively young and vessels under 20 years of age make up 91.1% of the overall fleet, which is aligned with developments and growth in recent years in liquefaction projects. Newer vessels are larger and more efficient, with far superior project economics for their operational lifetime. The global fleet is young, as only 11 active vessels are aged 30 years or older, including three that have already been converted to FSUs. At the end of 2019, there were approximately 20 vessels laid-up around the world.

The global LNG vessel orderbook counted 126 carriers as of year-end 2019, an impressive tally representing 23.3% of the current fleet size of 541 units. This illustrates shipowners' expectations that LNG trade will continue to grow, in line with the increase in liquefaction capacities in the coming years. Another 43 vessel deliveries are expected in 2020, accounting for a 7.9% increase in the global fleet count. The last of 15 initial Icebreaker-class vessels – highly innovative and more capex intensive ships that are able to traverse the Arctic – were delivered in 2019 to offtake from Novatek's Yamal LNG project in northern Russia. A fleet similar to the Yamal LNG fleet of LNG carriers might be ordered by Novatek.

[4] A high number of vessel deliveries are also expected in 2022 and 2023, but only known orders were included in the orderbook for purposes of this report..

Figure 5.2: Historical and Future Vessel Deliveries by Propulsion Type, 2016-2023



Source: Rystad Energy

Looking at propulsion systems, 2020 will see the prevalence of Low-Pressure Slow-Speed Dual-Fuel Winterthur Gas & Diesel engine (XDF) and M-Type, Electronically Controlled (MEGI) systems in place, capitalising on improved fuel efficiencies and lower emissions. An impressive 84 vessels ordered will have XDF propulsion systems in-place between 2020 and 2023, with 28 orders with the competing MEGI system. This represents a major shift from popular propulsion systems of the past, including steam turbine and Dual-Fuel Diesel-Electric (DFDE) engines. The South Korean shipbuilders, Hyundai Heavy Industries, Samsung Heavy Industries and Daewoo Shipbuilding, remain the top three LNG carrier suppliers on the market.

Spot charter rates are affected by balances between shipping demand and supply, in turn driven by liquefaction capacity and LNG vessel deliveries. Charter costs in 2019 began strong at approximately US$70,000 per day for steam turbine vessels and US$100,000 per day for TFDE/DFDE. Rates proceeded to level off to approximately US$30,000 for steam turbine vessels and about US$40,000 for TFDE/DFDE vessels, varying as expected with summer months impacting LNG shipment volumes. Sanctions on China Ocean Shipping Company Limited (COSCO) followed by a European storage build-up and sustained increases in US production caused an acute increase in charter prices. Rates (West of the Suez) peaked in late October at US$105,000 for steam turbine vessels, US$145,000 for TFDE/DFDE vessels and US$160,000 for XDF/MEGI vessels.

The increase in liquefaction and regasification capacity has driven LNG trade voyage growth globally. Increasing 11% YoY, LNG trade voyages reached 5,701 by year-end 2019, a result of additional US and Australian liquefaction capacity coming online. Asia as a destination made up the majority of voyages, accounting for 3,848, or 67.5% of global voyages. However, lower seasonality in Asia alongside increased supply has lowered gas prices globally, reducing arbitrage spreads and hence increasing voyages to Europe disproportionately. Voyages to Asia increased 2% YoY in 2019, while voyages to Europe increased by 70% to 1,364, representing 23.9% of global voyages.

LNG Vessel – Courtesy of Shell

5.2. LNG CARRIERS

Containment Systems

LNG containment systems are designed to store LNG at a cryogenic temperature of -162 C (-260F). This has been a key element in designing containment systems for LNG carriers, which can be split into two categories — membrane systems and self-supporting systems. Membrane systems are mostly designed by Gaztransport & Technigaz (GTT), while self-supporting systems comprise mainly of spherical "Moss" type vessels. Due to the advantages highlighted in this section, modern newbuilds have for the most part adopted the membrane type.

Table 5.1: Overview of Containment Systems

	Membrane	Self-supporting
Current Fleet Count	419	122
Current Fleet proportion (%)	77.4%	22.6%
Systems	GTT-designed: Mark III, Mark III Flex, Mark III Flex+, NEXT1, CS1 Kogas-designed: KC-1	Moss Maritime-designed: Moss Rosenberg IHI-designed: SPB LNT Marine-designed: LNT A-BOX
Advantages	•Space-efficient •Thin and lighter containment system •Higher fuel-efficiency	•More robust in harsh weather conditions •Partial-loading possible •Faster construction
Disadvantages	•Partial-loading restricted •Less robust in harsh ocean conditions	•Spherical design uses space inefficiently •Slower cool down rate •Thicker, heavier containment system

Source: Rystad Energy

In both systems, a small amount of LNG is converted into gas during a voyage. This is referred to as boil-off gas, a direct result of heat transferred from the atmospheric environment, liquid motion (sloshing of LNG), the tank-cooling process and the tank-depressurisation process. Boil-off rates (in older LNGCs averaging around 0.15% of total volume per day), with recently built LNGCs are below 0.10% of total volume per day. Membrane and self-supporting systems can be further split into specific types, which are examined below.

The two dominant membrane type LNG containment systems are the Mark III and NO96, designed by Technigaz and Gaztransport (GTT), respectively, which subsequently merged to form Gaztransport & Technigaz (GTT). Membrane type systems have primary and secondary thin membranes made of metallic or composite materials that shrink minimally upon cooling. The Mark III has two foam insulation layers while the NO96 uses insulated plywood boxes purged with nitrogen gas. The KC1, a new membrane system designed by KOGAS, has also entered the market in recent years, breaking GTT's membrane monopoly.

For membrane containment systems, within a range of tank filling levels, the natural pitching and rolling movement of the ship at sea, and the liquid free-surface effect, can cause the liquid to move within the tank. It is possible for considerable liquid movement to take place, creating high impact pressure on the tank surface. This effect is called "sloshing" and can cause structural damage. The first precaution is to maintain the level of the tanks within the required limits: Lower than a level corresponding to 10% of the height of the tank or, higher than a level corresponding to normally 70% of the height of the tank. The membrane type system has become the popular choice due to space efficiency of the prismatic shape, although partial fillings may be restricted due to sloshing. GTT states a boil-off-rate of 0.07% for its Mark III Flex+ and NEXT1 membrane system, claiming title to least boil-off gas during a voyage.

Celebrating almost 50 years in operation, the Moss Rosenberg system was first delivered in 1973. LNG carriers with this design feature several self-supporting aluminium spherical tanks, each storing LNG insulated by polyurethane foam flushed with nitrogen. The spherical shape allows for accurate stress and fatigue prediction of the tank, increasing durability and removing the need for a complete secondary barrier. This also allows for partial loading during a voyage. However, owing to its spherical shape, the Moss Rosenberg system uses space inefficiently in comparison to membrane storage and its design necessitates a heavier containment unit.

The Sayaendo type vessel, produced by Mitsubishi, is a recent improvement to the traditional Moss Rosenberg system. The spherical tanks are elongated in an apple-shape, increasing volumetric efficiency. They are then covered with a lightweight prismatic hull to reduce wind resistance. Sayaendo vessels are powered by Ultra Steam Turbine plants, a steam reheat engine, improving efficiency on a regular steam turbine engine. The Sayaringo Steam Turbine and Gas Engine (STaGE) type vessel, also produced by Mitsubishi, is a further improvement on the Sayaendo type vessel. The STaGE vessel adopts the shape of the Sayaendo alongside a hybrid propulsion system, combining a steam turbine and gas engine to maximise efficiency. Eight STaGE newbuilds were delivered during 2018 and 2019.

The IHI-designed SPB Self-Supporting Prismatic type was first implemented in a pair of 89,900 cm LNG carriers in 1993, Polar Spirit and Arctic Spirit. Since then, it has been used in several LPG and small-scale LNG FSRU vessels before Tokyo Gas commissioned four 165,000 cm vessels with the design. These ships are intended for use in exporting LNG from the new Cove Point LNG liquefaction plant in the United States. The design involves tanks subdivided into four by a liquid-tight centreline, allowing for partial loading during the voyage. The result eliminates the issue of sloshing and does not require a pressure differential, claiming a relatively low boil-off-rate of 0.08%. It is worth noting that the SPB system has higher space efficiency and is lighter than the Moss Rosenberg design.

Lastly, the LNT A-BOX is a self-supporting design aimed at providing a reasonably priced LNG containment system with a primary and secondary barrier, made of stainless steel or 9% nickel steel and liquid-tight polyurethane panels, respectively. Similar to the IHI-SPB design, the system mitigates sloshing by way of an independent tank, with the aim of minimising boil-off gas. The first newbuild with this system in place, Saga Dawn, was delivered in December 2019.

Propulsion Systems

Propulsion systems impact capital expenditure, operational expenses, emissions, vessel size range, vessel reliability and compliance with regulations, outlining the importance of this decision.

Prior to the early 2000s, steam turbine systems running on boil-off gas and heavy fuel oil were the only propulsion solution for LNG carriers. Increasing fuel oil costs and stricter emissions regulations created a need for more efficient engines, giving rise to alternatives such as the Dual-Fuel Diesel Electric (DFDE), Triple-Fuel Diesel Electric and the Slow-Speed Diesel with Re-liquefaction plant (SSDR).

In recent years, modern containment systems generating lower boil-off gas alongside the prevalence of short-term and spot trading of LNG have spawned demand for more flexible and efficient propulsion systems in order to adapt to varied sailing speeds and conditions. These factors have resulted in a new wave of dual-fuel propulsion systems, also burning boil-off gas with a small amount of pilot fuel or diesel. This includes the high-pressured MAN B&W M-Type, Electronically Controlled, Gas Injection (MEGI) and low-pressured Winterthur Gas & Diesel XDF.

As propulsion systems are manufactured by third parties such as Wärtsilä, MAN B&W and Winterthur Gas & Diesel, different shipbuilders generally offer a variety of propulsion systems. As such, shipowners are not restricted to specific shipbuilders or geographies when choosing newbuild specifications best matching their purpose.

Steam Turbine

The use of steam turbines for ship propulsion is mostly now considered to be superseded technology and hiring crew with steam experience is difficult nowadays. In a steam turbine propulsion system, two boilers supply highly pressurised steam at over 500°C (932°F) to a high, and then low, pressure turbine to power the main propulsion and auxiliary systems. The steam turbine's main fuel source is boil-off gas, with heavy fuel oil as an alternative should the former prove insufficient. The fuels can be burned at any ratio and excess boil-off gas can be converted to steam, making the engine reliable and eliminating the need for a gas combustion unit (GCU). Maintenance costs are also relatively low.

The key disadvantage of steam turbines is the low efficiency, running at 35% efficiency when fully loaded (most efficient). The newer generations of propulsion systems, DFDE/TFDE and XDF/MEGI engines, are over 25% and 50% more efficient when compared to the steam turbine. There are currently 224 active steam turbine propulsion vessels, making up 41.4% of the total current fleet. There are no steam turbine vessels being built currently, showing the high adoption rates of newer technologies.

In 2015, an improvement on the steam turbine was introduced, involving reheating of the steam in-cycle in order to improve efficiency by over 30%. Aptly named the Steam Reheat system (or Ultra Steam Turbine), there are 12 active vessels with the propulsion in place but zero newbuilds due.

Dual-Fuel Diesel Electric/ Triple-Fuel Diesel Electric (DFDE and TFDE)

DFDE propulsion was introduced in 2006 as the first alternative to steam turbine systems, able to run on both diesel and boil-off gas. It does so in two separate modes, diesel and gas mode, powering electrical generators which then turn electric motors. Auxiliary power is also delivered through these generators, and a gas combustion unit (GCU) is in place should there be excess boil-off gas. The 2008 arrival of TFDE vessels has improved the adaptability of this type of vessel, allowing the burning of heavy fuel oil as an additional fuel source. Being able to choose from different fuels during different sailing conditions and prevailing fuel prices increases overall efficiency by up to 30% over steam turbine propulsion. In addition, the response of the vessels under a dynamic load such as during adverse weather conditions is considered to be excellent.

However, the DFDE and TFDE propulsion systems also have certain disadvantages. Capital outlays as well as maintenance costs are relatively high, in part due to the necessity for a GCU. Eventually in gas mode, knocking and misfiring could happen in case the BOG composition is out of the engine specified range. Knocking refers to ignition in the engine prior to the optimal point, which could be detrimental to regular engine operation. There were 17 DFDE/TFDE vessels delivered in 2019, increasing the number of active vessels to 186, representing 34.4% of the current fleet. Of newbuilds with identifiable propulsion systems, there are 6 vessels with TFDE/DFDE systems to be delivered.

Slow-Speed Diesel with Re-liquefaction plant (SSDR)

The SSDR was introduced alongside the DFDE propulsion system, for the 31 Q-Flex and 14 Q-Max LNGCs, running two low-speed diesel engines and four auxiliary generators with a re-liquefaction plant to return boil-off gas to LNG tanks in a liquid state. The immediate advantages are the minimisation of LNG wastage and being able to efficiently use heavy fuel oil or diesel as a fuel source. However, the heavy electricity use of the re-liquefaction plant can negate efficiency gains and restrict the SSDR only to very large carriers (to achieve economies of scale).

New environmental regulations relating to sulphur and nitrogen emissions might impact the feasibility of SSDR engines, requiring existing engines to burn low-sulphur fuels or even convert propulsion system type. There are currently 49 SSDR vessels in the active LNG fleet, 44 of which are Nakilat's Q-Class vessels. One additional Q-class vessel previously ran an SSDR engine before being converted to a MEGI-type vessel. Due to environmental regulations and the introduction of third-generation engines, there are currently zero SSDR engines on order.

High-Pressure Slow-Speed Dual-Fuel (MEGI)

Produced by MAN B&W, the M-Type, Electronically Controlled, Gas Injection propulsion system (commonly known as MEGI), pressurises boil-off gas and burns it with a small amount of injected diesel fuel. Efficiency is maximised as the slow speed engine is able to run off a high proportion of boil-off gas while minimising risk of knocking. Similar efficiency and reliability levels are observed when switching fuel sources.

Fuel efficiency is maximised for large-sized LNG carriers, the exact class of a majority of newbuilds today. As such, the current LNG fleet and orderbook reflect the apparent advantages of the MEGI propulsion system, introduced in 2015. A total of 48 vessels fitted with MEGI systems have since been received, with 28 additional newbuilds yet to be delivered.

Low-Pressure Slow-Speed Dual-Fuel (Winterthur Gas & Diesel XDF)

Originally introduced by Wärtsilä, the Winterthur Gas & Diesel XDF was premiered on a South Korean newbuild in 2017. The XDF burns fuel and air, mixed at a high air-to-fuel ratio, injected at a low pressure. When burning gas, similar to the MEGI system, a small amount of fuel oil is used as a pilot fuel. As the maintained pressure is low, the system is easier to implement and integrate with a range of vendors.

In terms of fuel consumption and efficiency, LNG carriers equipped with MEGI and XDF are comparable. Safety and emissions are where the XDF stands out, winning over the MEGI without an after treatment system with extremely low nitrogen oxide emissions. The MEGI makes up for this with slightly lower fuel/gas consumption and better dynamic response.

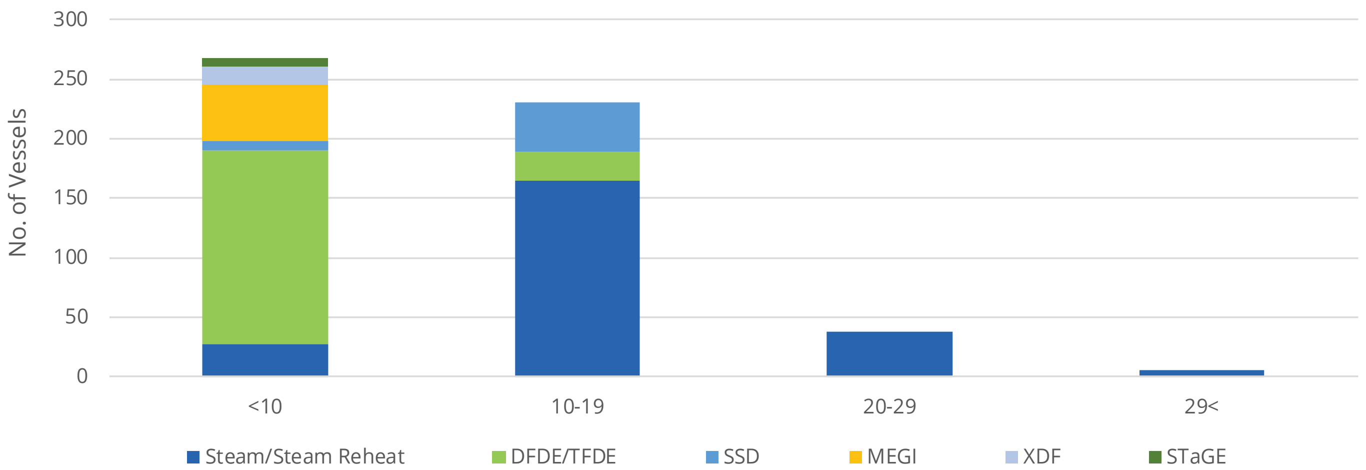
A relatively new system, there are currently 16 vessels with the XDF in service. The orderbook for LNG carriers contains an impressive 84 XDF vessel orders, thus representing the majority of 126 total newbuilds. With safety, efficiency and controlled emissions, the XDF is currently the preferred propulsion system among shipowners.

Steam Turbine and Gas Engine (STaGE)

First introduced in a 2018 delivery, the Sayaringo STaGE propulsion system runs both a steam turbine and a dual-fuel engine. Waste heat from running the dual-fuel engine is recovered to heat feed-water and to generate steam for the steam turbine, significantly improving overall efficiency. The electric generators attached to the dual-fuel engine powers both a propulsion system and the ship, eliminating the need for an additional turbine generator. In addition to efficiency, the combination of two propulsion systems improves the ship's adaptability while reducing overall emissions.

A Japanese innovation, STaGE systems have been produced exclusively by Mitsubishi, with eight newbuilds delivered during the course of 2018 and 2019. There are currently no STaGE vessels on order.

Figure 5.3: Current Fleet Propulsion Type by Vessel Age



Source: Rystad Energy

Steam turbine systems make up the majority of older vessels, with DFDE/TFDE and SSDR representing a small proportion of vessels aged over 10 years. As almost all the SSDR vessels comprise Qatari Q-Class ships, the age range is in line with when they were delivered. The entirety of MEGI, XDF and STaGE vessels are new due to recency of these innovations. Moving forward, XDF and MEGI systems will contribute to a significantly higher proportion of vessels.

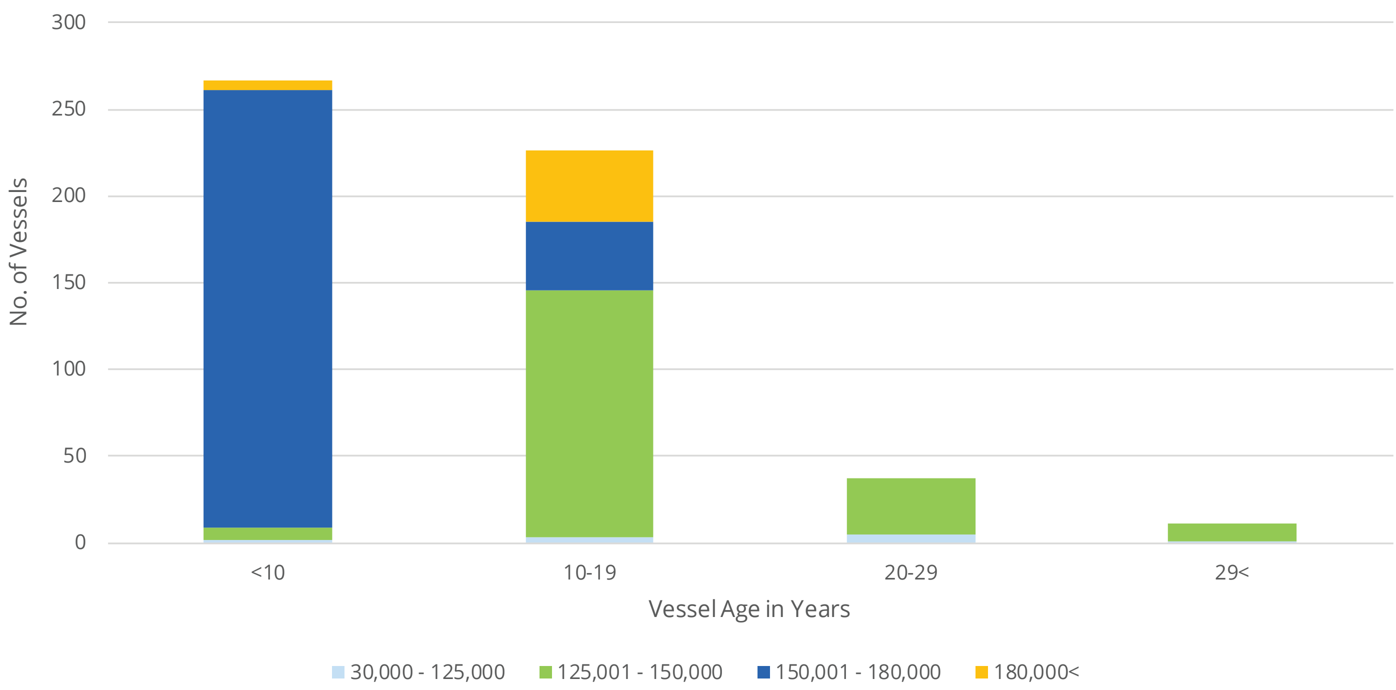
Vessel Age

The current global LNG fleet is relatively young, considering the oldest LNG vessel operating was constructed in 1977. Vessels under 20 years of age comprise 91.1% of the fleet, consistent with liquefaction capacity growing rapidly from the turn of the century. In addition, newer vessels are larger and more efficient, with far superior project economics over their operational lifetime. This is a result of improvements in technology and an increase in global LNG trade. As capacity and global LNG demand continue to grow with each passing year, this trend is slated to continue.

With financial and safety concerns in mind, shipowners plan to operate a vessel for 35-40 years before it is laid-up, a term describing vessels left idle. A decision can then be made on whether to scrap the carrier, convert it to an FSU/FSRU, or return it to operation should market forces pick up.

When commissioning a newbuild, a shipowner determines vessel capacity based on individual needs, ongoing market trends and technologies available at the time. Liquefaction and regasification plants also have berthing capacity limits, an important consideration. As individual shipowner needs are also affected largely by market demand, newbuild vessel capacities have stayed primarily within a small range around period averages, illustrated by the figure below.

Figure 5.4: Current Fleet Capacity by Vessel Age

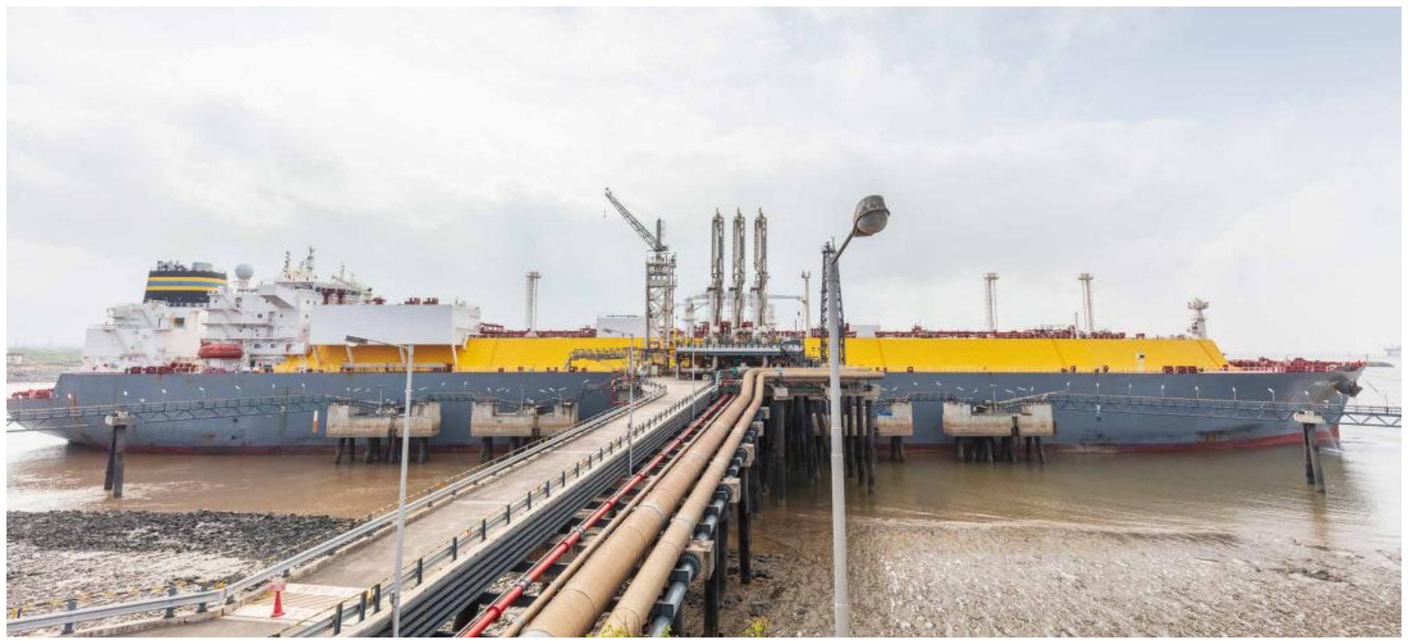


Source: Rystad Energy

Due to the dominance of steam turbine propulsion, vessels delivered before the mid-2000s were exclusively smaller than 150,000 cm, as this was the range best suited to steam turbine engines. The LNG vessel landscape changed dramatically when Nakilat, the Qatari shipping line, introduced the Q-Flex (210,000 to 217,000 cm in size) and Q-Max (263,000 to 266,000 cm in size) vessels, specifically targeting large shipments of LNG to Asia and Europe. These vessels achieved greater economies of scale with their SSDR propulsion systems, representing the 45 largest LNG carriers ever built.

After the wave of Q-Class vessels, most newbuilds settled at a size between 150,000 and 180,000 cm, making up 53.6% of the current fleet. The technology developments leading to the adoption of this size are the new propulsion systems, such as the MEGI, XDF and STaGE types, that maximise fuel efficiency between 170,000 and 180,000 cm. Another crucial factor is the new Panama Canal size quota – only vessels smaller than this size were initially authorised to pass through the new locks, imperative for any ship engaged in trade involving US LNG supply. In May 2019 the Q-Flex LNGC 'Al Safliya', which is larger than 200,000 cm, became the first Q-Flex type LNG vessel and largest LNG vessel by cargo capacity to transit the Panama Canal.

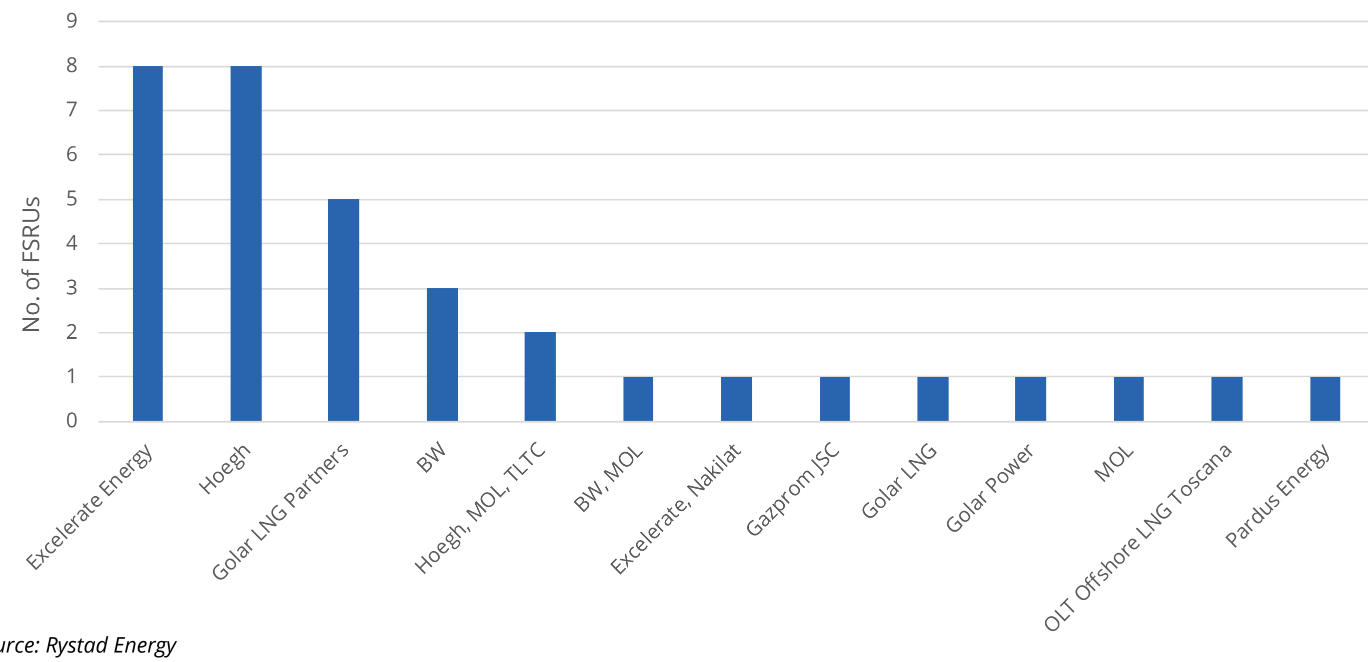
Every vessel delivered in 2019 and 95.5% of the LNG orderbook with determinable capacities fall within the 150,000 to 180,000 cm capacity range.



LNG Vessel at Shell's Terminal at Hazira - Courtesy of Shell

5.3. FLOATING STORAGE REGASIFICATION UNIT OWNERSHIP (FSRUs)

Figure 5.5: Active Number of FSRUs Owned by Shipowner (Vessel Count)



Source: Rystad Energy

6.3% of Global Fleet
are FSRU Vessels

Able to store and convert LNG to gaseous form, FSRU vessels have become popular over the past two decades, now contributing to 6.3% of the global fleet. Compared to traditional regasification plants, FSRUs offer better flexibility, lower capital outlay and a faster means of implementing LNG sourced natural gas. There are currently 34 FSRUs in the global LNG fleet, including two delivered in 2019. Shipowners Hoegh LNG, Excelerate Energy and Golar LNG Partners have the largest current FSRU fleets.

FSRUs offer markets a 'plug-and-play' solution to importing LNG, with the flexibility of meeting demand as needed before being redeployed elsewhere. Another important consideration is that FSRUs are deployed off the coast of the markets they serve instead of on land, offering an advantage to land-scarce regions or hard-to-reach areas.

While operating expenses are higher for an FSRU, total capital expenditure can be as little as half that of an onshore terminal. FSRUs can either be built from scratch or converted from an old LNG carrier. The duration of construction is also significantly shorter than that of an onshore terminal, as low as 50% for a newbuild or even lower if the FSRU is an LNG carrier conversion.

However, FSRUs have not been free of issues. Delivery delays, power cuts and rising costs have affected certain projects, slightly dampening demand for the vessels. In addition, spikes in charter rates can motivate shipowners to utilise the ships as carriers, reducing the number of FSRUs operating as regasification or storage units. Within the current global fleet, only 24 FSRUs were used as terminals for the entirety of 2019, illustrating the extent to which operators are capitalising on their adaptability.

Despite this, FSRUs are expected to remain a popular storage and regasification solution for years to come. There are seven FSRU newbuilds due for delivery in 2020 and 2021, alongside several large-scale conversions by companies such as Sembcorp, Hudong-Zhonghua and CSSC. Furthermore, the governments of Singapore, India and Thailand have each expressed interest in employing FSRUs to contribute to their energy supply in the near future.

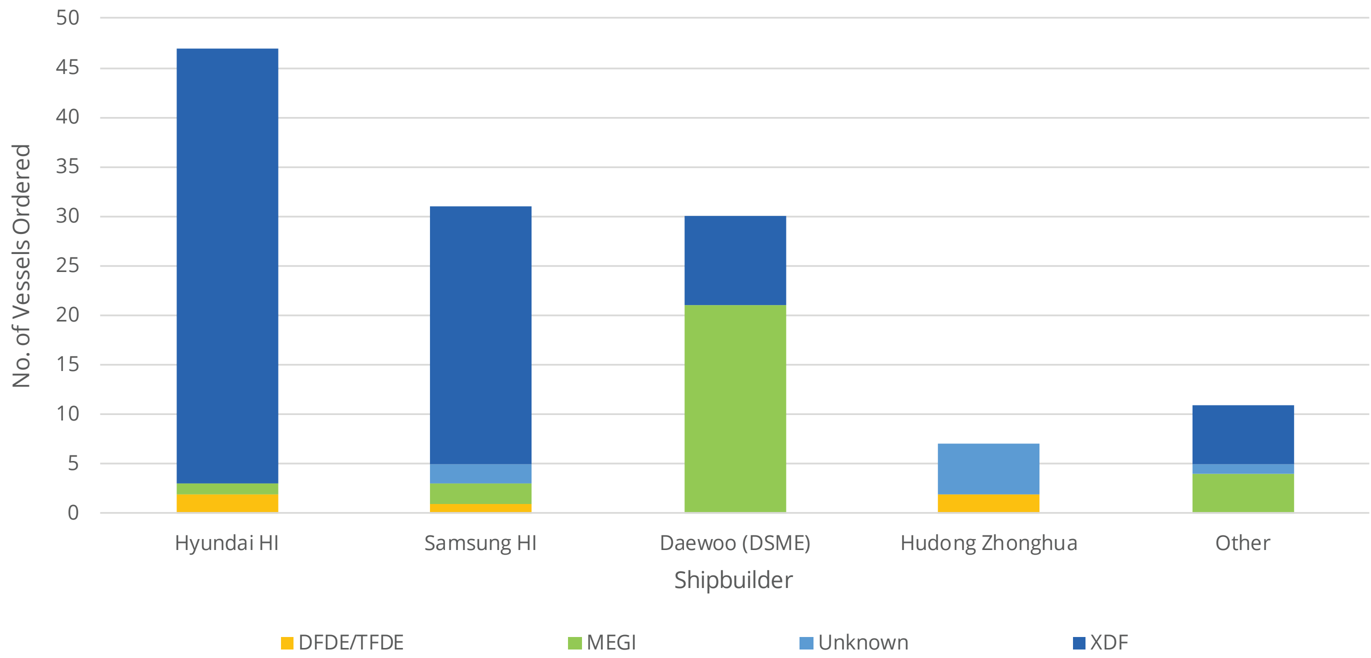
[4] FSRUs with capacity above 30,000cm are included
[5] Golar LNG Partners is in general partnership with Golar LNG while Golar Power is a joint venture between Golar LNG and Stonepeak Infrastructure Partners

5.4. 2020 LNG ORDERBOOK AS OF YEAR-END 2019

126 Vessels
in Orderbook are FSRU Vessels

Of the 126 vessels in the global LNG vessel orderbook as of 2019 year-end (carriers and FSRUs), it is worth noting that almost one-third of all current newbuilds are to be delivered to shipowners affiliated with typical LNG buyers. The remainder consists of shipowners affiliated with typical LNG sellers, traders and independent shipping companies, betting on continued LNG cross-border demand.

Figure 5.6: LNG Newbuild Approximate Orderbook by Propulsion Type and Builder



Source: Rystad Energy

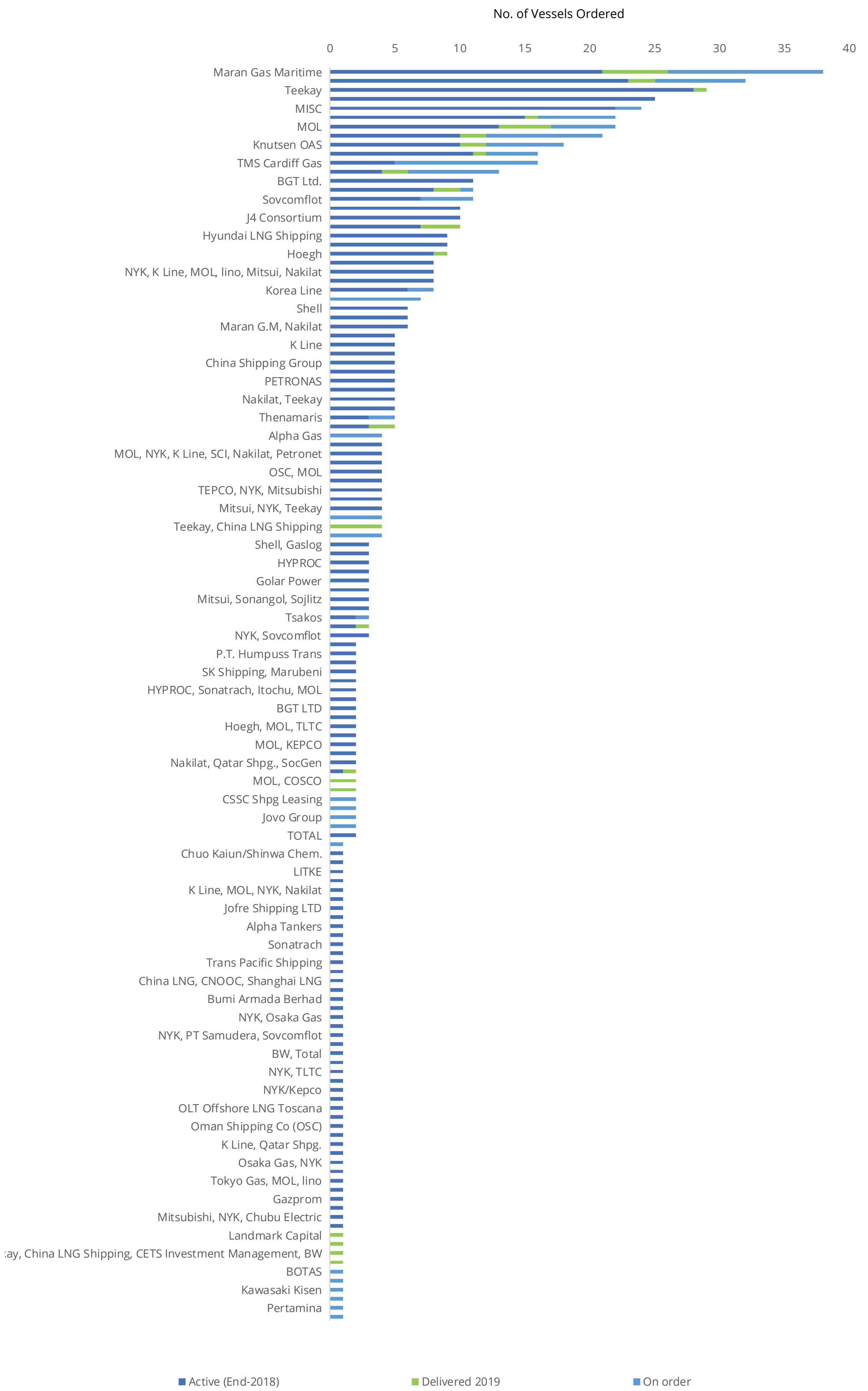
XDF and MEGI propulsion systems will experience strong growth in 2020, capitalising on better fuel efficiencies and lower emissions. Significantly, 84 vessels on order will have XDF propulsion systems in-place. The competing MEGI system has 28 orders, while DFDE/TFDE account for 6 backlog orders, all due for delivery in 2020 and 2021. A high proportion of 95.5% of newbuild vessel capacities fall within the 150,000 to 180,000 cm capacity range. This is a result of maximising MEGI and XDF efficiencies while keeping to new Panama Canal lock size limits.

The top three LNG builders – South Korean yards Hyundai Ulsan and Samho, Samsung Heavy Industries and Daewoo Shipbuilding – have approximately 47, 31 and 30 vessels on their orderbooks respectively.

Hyundai and Samsung are working on a large proportion of newbuilds with XDF systems, while Daewoo's orders include a large number of MEGI engines, possibly developing a specialty. Elsewhere, Chinese builder Hudong-Zhonghua has a notable seven carriers on order.

Qatar is rapidly increasing its liquefaction capacity, expressing ambitions to move from 77 MTPA at present to 126 MTPA by 2027. To support this increase, Qatar Gas has expressed its intention to commission a large order of LNG carriers. In 2019, the Qatari shipping company Nakilat acquired a 60% stake in four newbuilds with Maran Gas, and purchased full ownership of four carriers that had previously been jointly owned with International Seaways.

Figure 5.7: Global LNG Fleet and Approximate Orderbook by Shipowner[6]

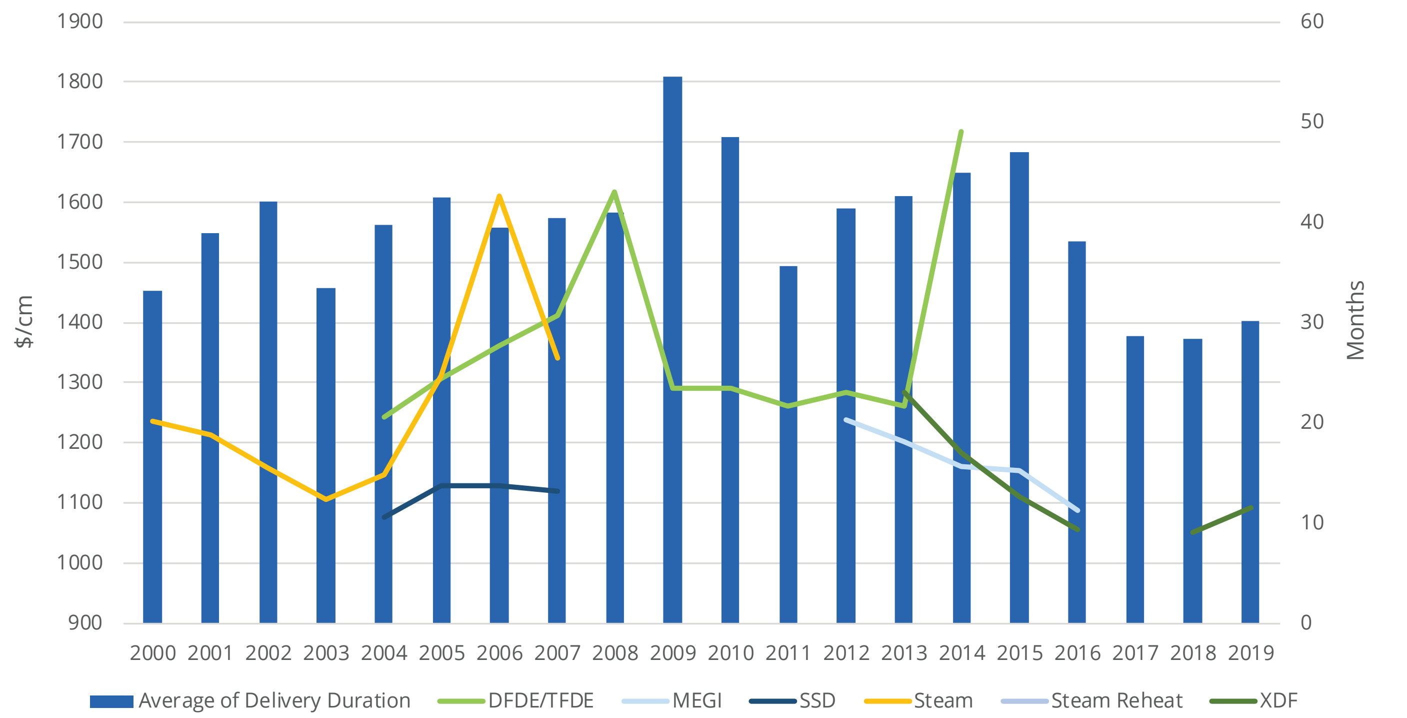


Source: Rystad Energy

[6] Shipowners or consortiums with 4 or more current and ordered vessels were included.

5.5. VESSEL COSTS AND DELIVERY SCHEDULE

Figure 5.8: LNG Vessel Delivery Schedule and Newbuild Cost



Source: Barry Rogliano Salles, Rystad Energy

Most New LNG Vessels

Delivered 30-50 Months from Order Date

The cost of constructing an LNG carrier is highly dependent on characteristics such as propulsion systems and other specifications involving the ship design. Historically, DFDE/TDFE vessels started out being pricier than steam turbine vessels, with the higher newbuild costs offset by efficiency gains from operating more modern ships. DFDE/TFDE newbuild costs have varied heavily over the years due to different specification standards – a prominent example is the 2014 peak of over US$1,700/cm due to 15 ice-breaker class vessels ordered to service Yamal LNG. These vessels, delivered in 2017, were priced at about US$320 million which drove up average prices.

While vessels equipped with XDF systems started out marginally more expensive per cubic metre than vessels with MEGI propulsion systems, they are now cost competitive. From the Newbuild Cost chart, we observe that the cost for XDF and MEGI vessels have trended in line, and have come down from an initial US$1,200-US$1,300/cm to below US$1,100/cm. This comes amidst stiff competition between Korean, Japanese and Chinese shipbuilders, with aggressive pricing keeping newbuild costs relatively low.

Barring unusual delays, most new LNG vessels have been delivered between 30 to 50 months from order date. Despite changes in average vessel sizes over time, shipyards have been able to construct on a consistent delivery schedule, with variance within this band occurring during introduction of new propulsion systems. This can be attributed to shipyards having to adjust to novel designs with new engines, an example being delivery duration peaks in 2009, reaching over 50 months in the years following introduction of DFDE/TFDE systems. As Korean shipbuilders are becoming more experienced in delivering XDF and MEGI vessels, the average delivery duration for newbuild orders is expected to remain around 30 months moving forward.

5.6. CHARTER MARKET

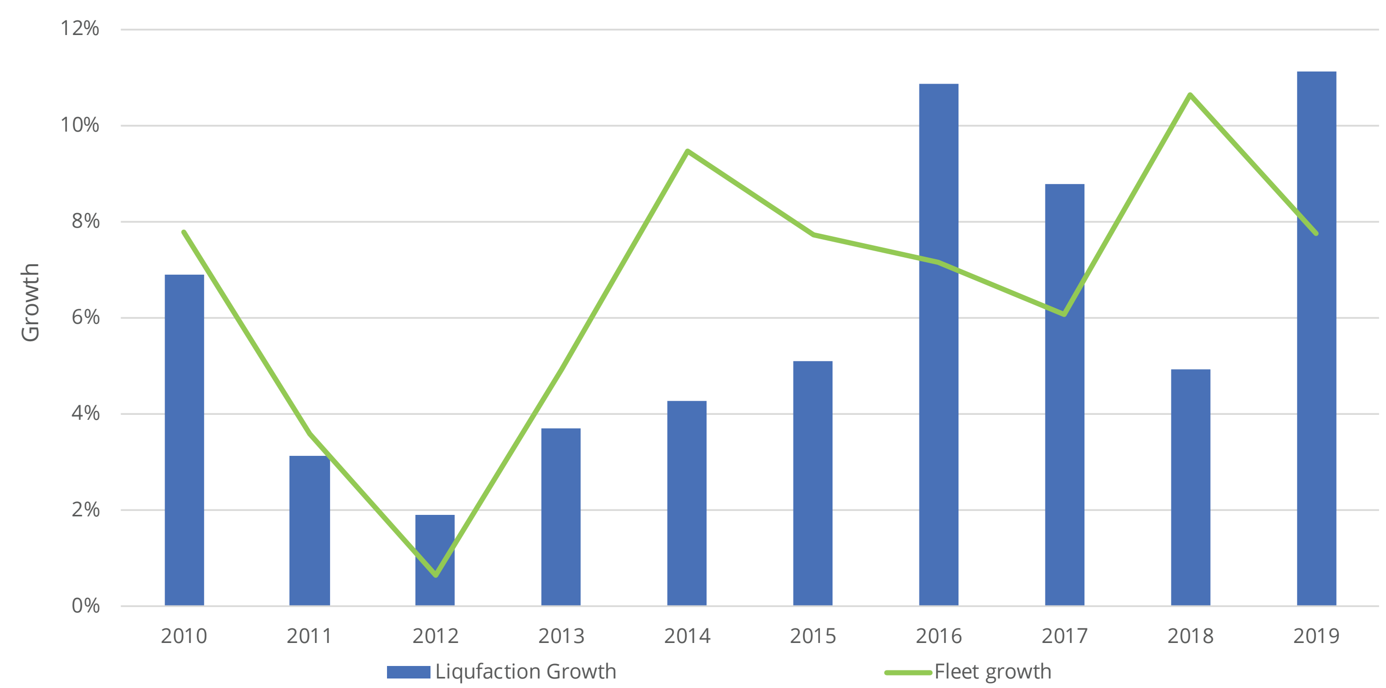
Delivery Costs

Took Up Higher Proportion of Netbacks in 2019

With gas prices depressed globally, delivery costs take up a higher proportion of netback calculation when trading LNG. Charter costs thus greatly affect LNG players' market strategy, whether for spot or term charter. Charter costs in 2019 started at about US$70,000 per day for steam turbine vessels and US$100,000 per day for TFDE/DFDE vessels in 2019, well above the previous year mean. Rates reduced to approximately US$30,000 for steam turbine vessels and about US$40,000 for TFDE/DFDE vessels in the second quarter of the year, before varying as summer months impacted LNG trade flows. A spike in late October drove peak charter prices (West of the Suez) to US$105,000 for steam turbine vessels, US$145,000 for TFDE/DFDE vessels and US$160,000 for XDF/MEGI vessels.

LNG charter rates are affected by demand for shipping LNG (driven by liquefaction capacity) and supply of shipping capacity (a function of global fleet size). Historically, LNG was commonly sold and purchased under long-term contracts, encouraging shipowners to enter term charters with bigger players. A relatively small amount of vessel capacity was available on a spot basis for arbitrage opportunities. Lack of liquidity could lead charter rates to be largely affected by the mismatch between supply and demand.

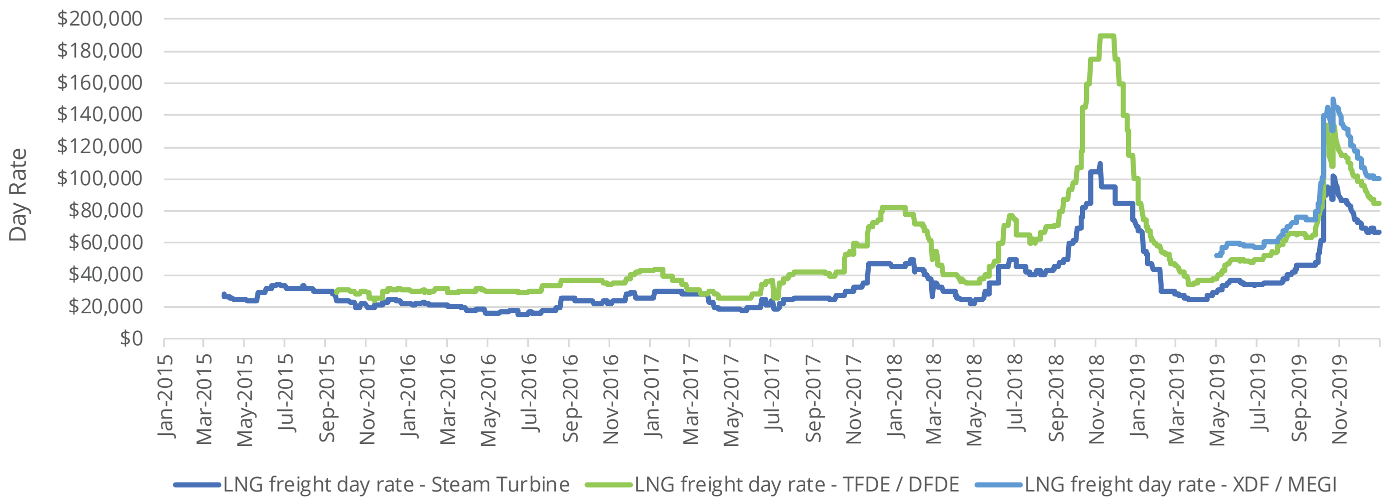
Figure 5.9: Liquefaction Capacity Growth vs LNG Global Fleet Count Growth for 2010-2019



Source: Rystad Energy

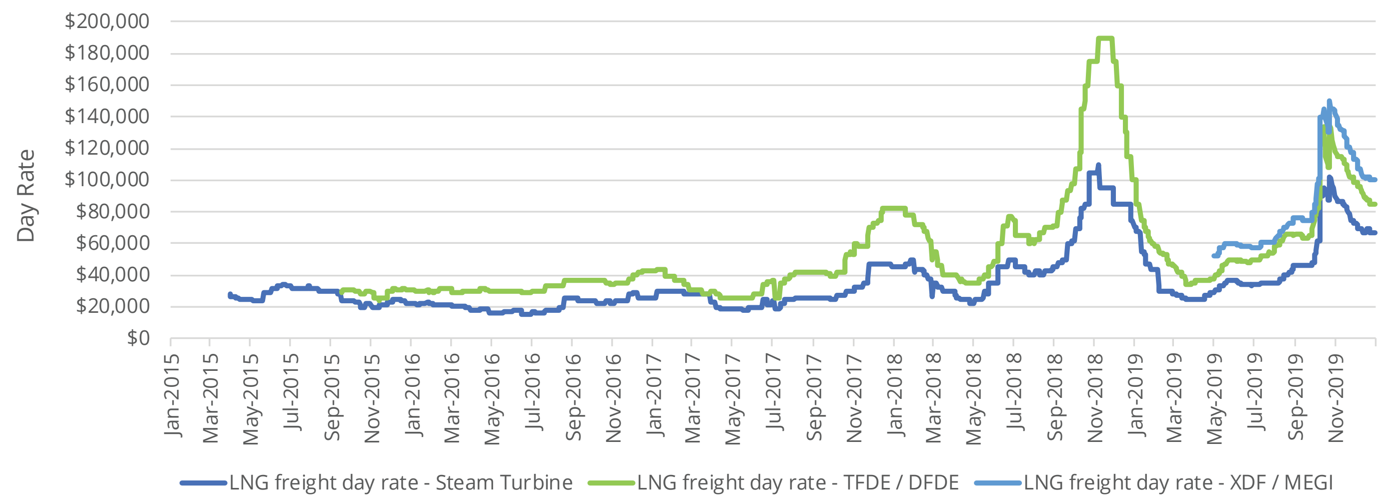
In the early 2010s, fleet growth was well balanced with additional liquefaction coming online, resulting in a stable charter market. However, vessel deliveries far outweighed liquefaction capacity growth from 2013 onwards, resulting in a glut of LNG shipping capacity and a steady decline of charter rates. This continued until 2015, after which they remained between US$15,000 and US$50,000 (for steam turbine engines, both East and West of Suez) until the fourth quarter of 2017, when a rapid increase in Asian LNG demand sparked an initial increase in spot charter rates. Throughout 2018, spot charter rates were volatile, swinging between previous highs and corrections. Notably, 4Q 2018 saw an unprecedented spike in charter prices, with TFDE day rates (East of Suez) reaching US$190,000 per day for the majority of November. This happened because winter inventory floating storage filled up quickly, which left vessels off the charter market while they waited to discharge cargo, acutely reducing supply.

Figure 5.10: Spot Charter Rates East of Suez in 2019



Source: Rystad Energy Research and Analysis, Argus Direct

Figure 5.11: Spot Charter Rates West of Suez in 2019



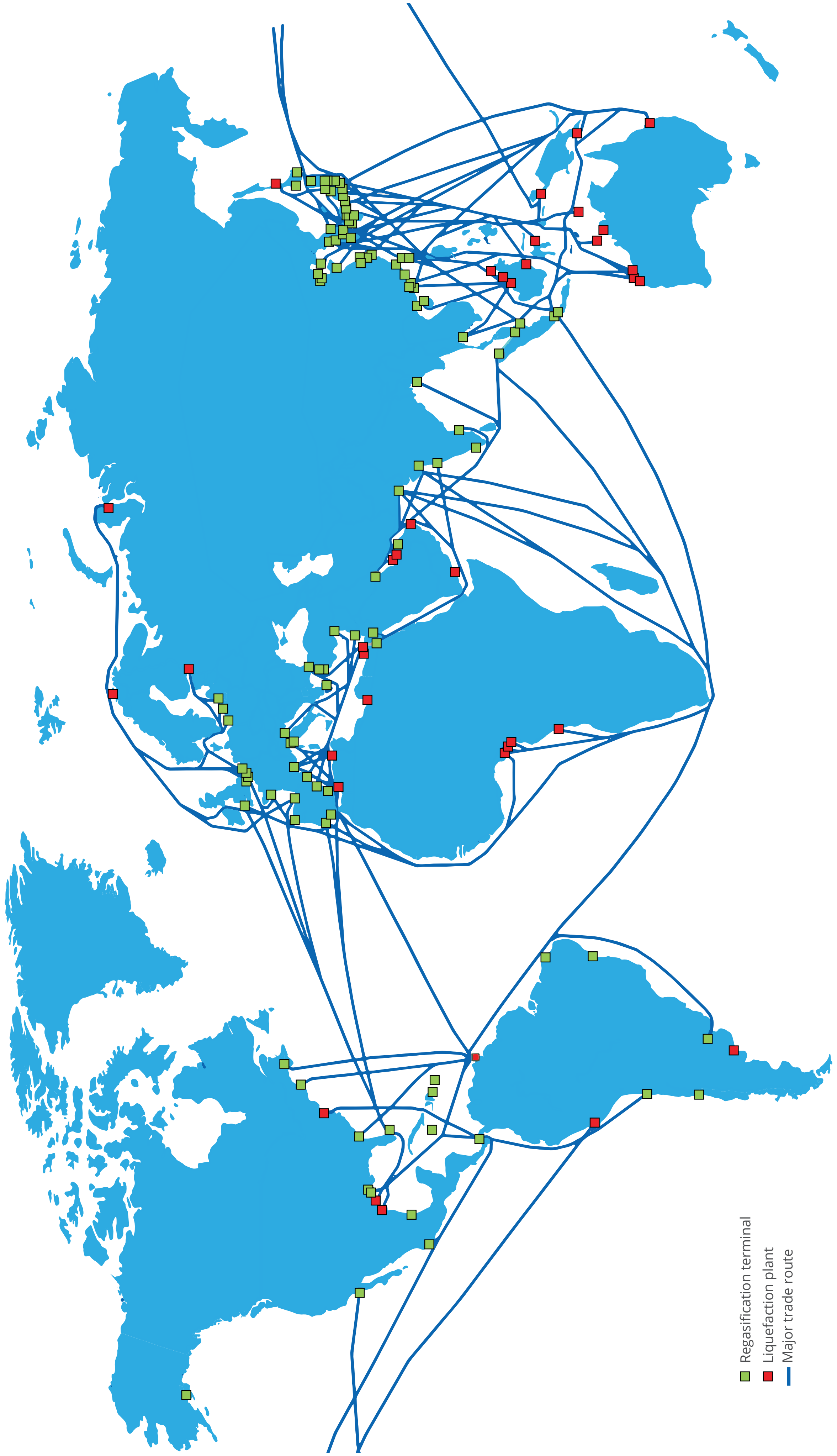
Source: Rystad Energy, Argus Direct

Following the peak in 4Q 2018, the general spot charter market started at a high of about US$70,000 per day for steam turbine vessels and US$100,000 per day for TFDE/DFDE vessels in 2019. Rates slowly returned to about US$30,000 for steam turbine vessels and about US$40,000 for TFDE/DFDE vessels in 2Q 2019, following regular seasonal variations till 3Q 2019, before it rode an upward rollercoaster in October 2019. The spike was mainly caused by US sanctions placed against Chinese state-owned shipping company COSCO for breaching sanctions on transactions involving oil from Iran. The US-enforced sanctions spilled into joint ventures with other big LNG players such as Teekay and MOL, removing a great number of vessels available for charter in both the Atlantic and Pacific basins. In late October 2019, peak charter prices (West of the Suez) reached US$105,000 for steam turbine vessels, US$145,000 for TFDE/DFDE vessels and US$160,000 for XDF/MEGI vessels.

While the sanctions were waived soon after, high charter prices were sustained by a repeat European storage build-up and increased US production. Low gas prices across Europe and Asia have encouraged cargoes to be used as floating storages and wait for rising gas prices in 2020. LNG deliveries from the US travel a greater distance to their destinations and therefore require vessels to be chartered for longer, leading to a tightening of LNG shipping supply. 2019 ended with spot charter prices higher than in 2018, at US$72,000 for steam turbine vessels, US$93,000 for TFDE/DFDE vessels and US$105,000 for XDF/MEGI vessels.

The increasing price differentials between vessels with two-stroke propulsion (XDF/MEGI), dual-fuel and tri-fuel diesel-electric propulsion (TFDE/DFDE) and steam turbine engines can be explained by efficiency gains from using newer propulsion systems. Steam turbine engines are significantly less efficient than TFDE/DFDE systems, which in turn are less efficient than XDF/MEGI engines. In addition, charterers conscious about vessel emissions or boil-off rates also increasingly demand newer technology, which widens the price differentials further. Market players must accurately balance fuel efficiencies, boil-off gas savings and higher costs when choosing which propulsion system to charter. It is worth noting that higher long-term charter demand for XDF/MEGI systems has led to a larger proportion of TDFE/DFDE and steam turbine vessels available on the spot market.

LNG charter rates have continued to slide into the first three months of 2020, driven by both seasonal demand patterns as well as the impact of the COVID-19 virus. West of Suez DFDE/TFDE day rates bottomed out at US$39,500 in 2019, while they have reached a low of US$35,000 as of March this year. This shows that the reduced LNG demand as a consequence of COVID-19 has likely also impacted charter rates.



Regasification terminal
Liquefaction plant
Major trade route

Figure 5.12: Major LNG Shipping Routes, 2020

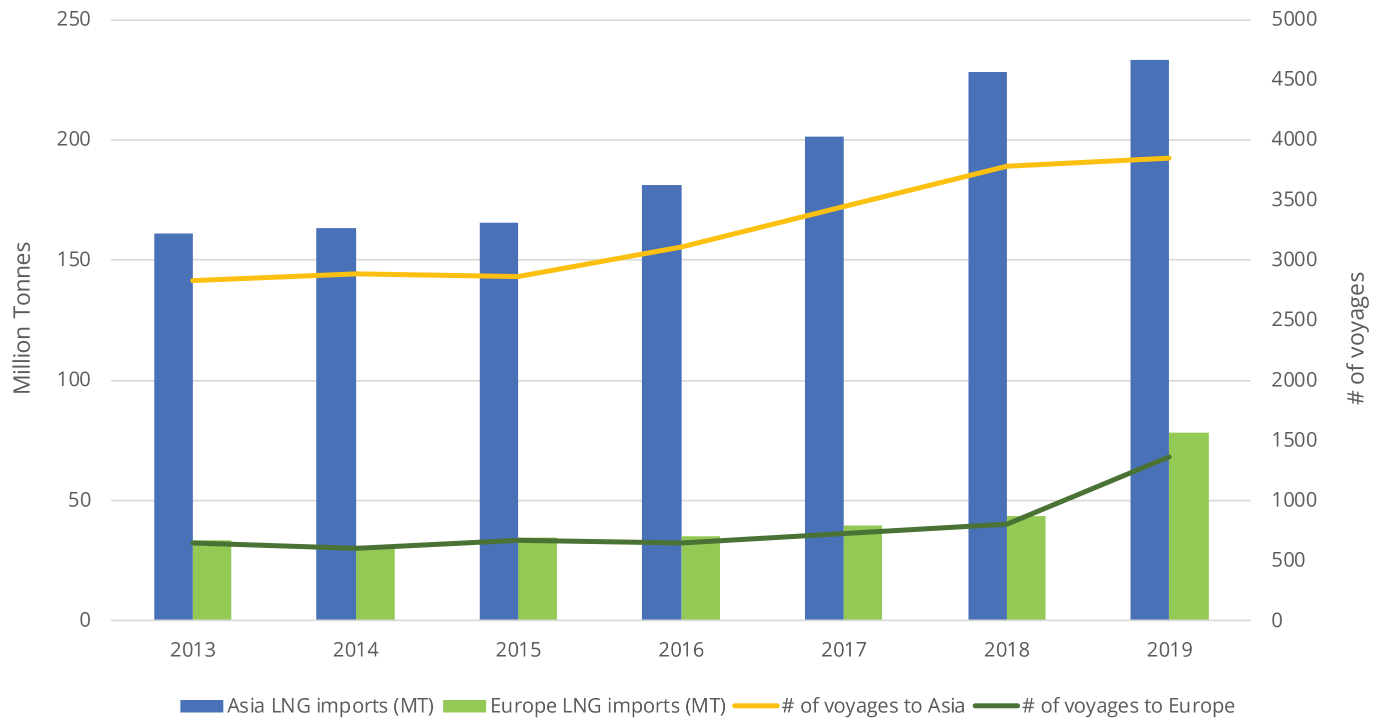
Source: Rystad Energy

5.7. FLEET VOYAGES AND VESSEL UTILISATION

5,701 LNG Trade Voyages in 2019

A total of 5,701 of LNG trade voyages were completed in 2019, an 11% increase compared to the 2018 level of 5,130 voyages, thanks to new supplies from the US and Australia, demand growth in Asia and the ability to absorb these extra volumes in European markets. The ramp-up from Sabine Pass T5 and Corpus Christi T1 in the US and Ichthys LNG and Wheatstone LNG in Australia contributed 18 MT of LNG in 2019, 11 MT more than in 2018. The start-ups of Cameron LNG T1, Elba Island and Freeport LNG T1 in the US and Prelude FLNG in Australia added another 2 MT to the market in 2019. The abundant new supplies, coupled with mild seasonality in Asia, have brought down gas prices to record lows on a global basis, reduced arbitrage spreads across continents and diverted more-than-expected LNG cargoes to Europe. 3,848 LNG trade voyages were completed for Asia in 2019, a slight 2% increase YoY. However, a record of 1,364 LNG voyages were for Europe in 2019, a 70% rise compared to 2018.

Figure 5.12: LNG Imports and Number of Voyages to Asia and Europe, 2013-2019



Source: Rystad Energy, Refinitiv Eikon

A project completed in 2016 widened and deepened the Panama Canal, which allows for more transits. The voyage distance and time from US's Sabine Pass terminal to Japan's Kawasaki LNG site can be reduced to 9,400 nautical miles (nm) and 29 days transiting Panama Canal, compared to 14,500 nm and 45 days through Suez Canal and close to 16,000 nm and 49 days via the Cape of Good Hope. The most common voyage globally in 2019 was from Australia to Japan, with 447 voyages within the year. The most common voyage to Europe in 2019 was from Russia, with 286 shipments during the year, followed by 265 voyages from Qatar and 181 voyages from the US, respectively. The 5,701 LNG trade voyages were done by 541 vessels in 2019. The average number of voyages completed per vessel was 10.5 in 2019, a slight rise from the 2018 level of 10.3. The voyage time averaged at 12.8 days in 2019, remaining constant from 2018. It normally takes longer voyage time and fewer completed trips from the Atlantic basin to Asia, but since a significant number of LNG trades were diverted from Asia to Europe, the average voyage times for 2018 and 2019 were quite close.

The 2020 LNG shipping market will most likely be negatively affected by the COVID-19 virus outbreak, as demand for LNG is reduced due to lower activity in the industrial and commercial sectors. We have already seen a decline in Chinese LNG demand, and we expect the same thing to happen to other markets as the virus continues to spread. The lower demand will ultimately translate into fewer voyages for the LNG carriers.

5.8. NEAR TERM SHIPPING DEVELOPMENTS

92% of LNG Carrier Fleet
Uses Boil-Off Gas as Fuel

Since the International Maritime Organization (IMO) and other regulatory bodies have started to impose more stringent regulations to reduce pollution emissions, including air pollution, LNG has become the main alternative fuel in the maritime segment. However, boil-off gas has been used for fuel on board of LNG carriers for many years for technical reasons.

Nowadays around 92% of the LNG carrier fleet, including FSRU's and small scale carriers, use boil-off gas as fuel for propulsion and electricity generation on board. This has made the fleet cleaner than any other shipping segment in terms of sulphur oxides (SO_x), nitrogen oxides (NO_x) and carbon dioxide (CO_2) emissions. This gas fuel technology is mature and equipment is amply available to facilitate the use of cargo as fuel.

Recently the increased requirements for energy efficiency in shipping have triggered further innovation in the segment of LNG carriers. Fuel consumption is continuously being reduced due to two main factors; on one hand the energy efficiency design index (EEDI) introduced by IMO Marpol regulations and on the other hand the drive to reduce shipping OPEX of which fuel is a significant part.

In addition to the need to be highly efficient, the LNG carrier segment at the moment is also more flexible and dynamic than a few years ago. Many parameters are to be taken into consideration such as new routes and navigation patterns, destination changes, partial cargo deliveries, reloads, speed reduction, terminals compatibility, ship to ship LNG transfers, etc.

In order to respond to changing market demands many technologies have been developed recently, and there are evolutions and new equipment types that can be implemented in the near future, aiming to meet the evolving expectations of different stakeholders. These technologies are mainly around containment systems with lower boil-off rates, very efficient propulsion and electricity generation systems and new boil-off handling systems such as sub-cooling or re-liquefaction equipment.

Despite the fact that 174-180,000 m3 carriers are now the standard size, new designs of 200,000 m3 LNG carriers with four tanks have been proposed by relevant shipyards in an attempt to offer shipowners optimised transportation cost. These designs, categorised as Neo Panamax LNG carriers, are able to transit the Panama canal, and might be an alternative for exports from the US to the importing countries in the Far East, provided that terminals can accommodate such larger ships.

In order to further reduce consumption, other ideas involving power take-off systems on main propulsion engines, air lubrication and two-stroke engines to be used as electricity generators have been evocated. Compact COGES systems have also been proposed to optimise cargo volume while maintaining the same ship size.

Another interesting trend in the LNG carrier segment is the new Northern Sea Route. Following the commissioning of 15 icebreaking LNG carriers for the Yamal LNG terminal, new shipping capacity will be required for the Arctic LNG-2 project. Other projects have also been announced in the Arctic environment and those will also require similar capacity if sanctioned. Permanent transhipment points might also be developed at suitable locations. At these locations the icebreaking carriers will transfer their cargo into conventional carriers to make the transportation more efficient on ice-free segments to their final customers.

Other challenges in this segment have related to FSRU projects, where weather conditions on site have led to different mooring (or anchoring) arrangements, LNG transfer systems and gas offloading for instance. Operability window is key, especially in projects on open seas where hydrodynamic conditions may create difficulties for the LNG carriers to manoeuver, to be moored to the FSRU and to transfer the cargo. Cargo containment systems are also suitably reinforced in case of membrane technologies, depending on the site environment, which usually increases the boil-off rate. Since most of the FSRU projects look to be flexible, i.e. carriers are able to transport and/or regasify LNG, this is a technical aspect to be taken into consideration. The ability to relocate units is the prime advantage of these projects, considering that in some cases permanent import terminals will be installed after a few years of FSRU operations. In any case, FSRU's have proven to be a good way of opening new markets in a relatively short time.

Small scale LNG carriers also have challenges related to efficiency and flexibility. Newly developed carriers specifically designed for bunkering LNG will have to be equipped with suitable transfer systems, as LNG use for fuel grows in this fleet, and clients being of different ship size and type. In this segment, the development of inland or sheltered water bunkering units has been significant in the last couple of years with presently almost half of the fleet on the orderbook being units of reduced capacity for river, estuary or port operation only.

In fact this brand new fleet of LNG bunkering ships or barges is under continuous development to provide clean fuel to a growing fleet that uses LNG as fuel. Despite the fact that other factors are key for further growth of the use of LNG as fuel for both newbuilds and conversions, LNG is a proven fuel with many applications at present, and many alternative technologies. Compliance with the IMO low sulphur regulation, implemented globally in January 2020, can be also achieved through the use of low sulphur heavy fuel oil, marine diesel oil or exhaust cleaning systems like scrubber technologies. However there are also some technical challenges such as compatibility between different fuel suppliers or bans by local regulators on open loop scrubbers, among others. Price differentials between compliant fuels will also play a role in the consolidation of the use of LNG as fuel. LNG fuelled projects tend to copy technology already used on LNG carriers. Type C tanks for instance are the preferred types when the required autonomy is low and membrane, and prismatic tanks are proposed for ships with larger fuel volumes. The first membrane (GTT Mark III) gas fuelled and LNG bunkering ships are about to be delivered.

Containerised sea transportation of LNG is not new, but further developments and innovation are taking place. The lack of pipe and terminal infrastructure in some locations have led to the use of existing container routes to transport LNG in ISO containers, or to propose the implementation of specific ships for the purpose of small scale distribution of LNG instead of trucking LNG.

Last but not least, gas to power projects in some cases will involve floaters as an integrated solution in order to deliver electricity to consumers. For instance, conversions of LNG carriers and power ships are under development at the moment, mainly for emerging markets. FSRU projects in combination with gas, or dual fuel floating units (ship or barge type), will be deployed, thereby opening new import markets for LNG and replacing other more pollutant fuels such as coal or heavy fuel oil.

LNG Vessel

6 LNG Receiving Terminals

23.4 MTPA of receiving capacity was added in 2019

+6 new terminals between 2019 – February 2020

+3 expansions at existing terminals between 2019 – February 2020

821 MTPA of global regasification capacity as of February 2020

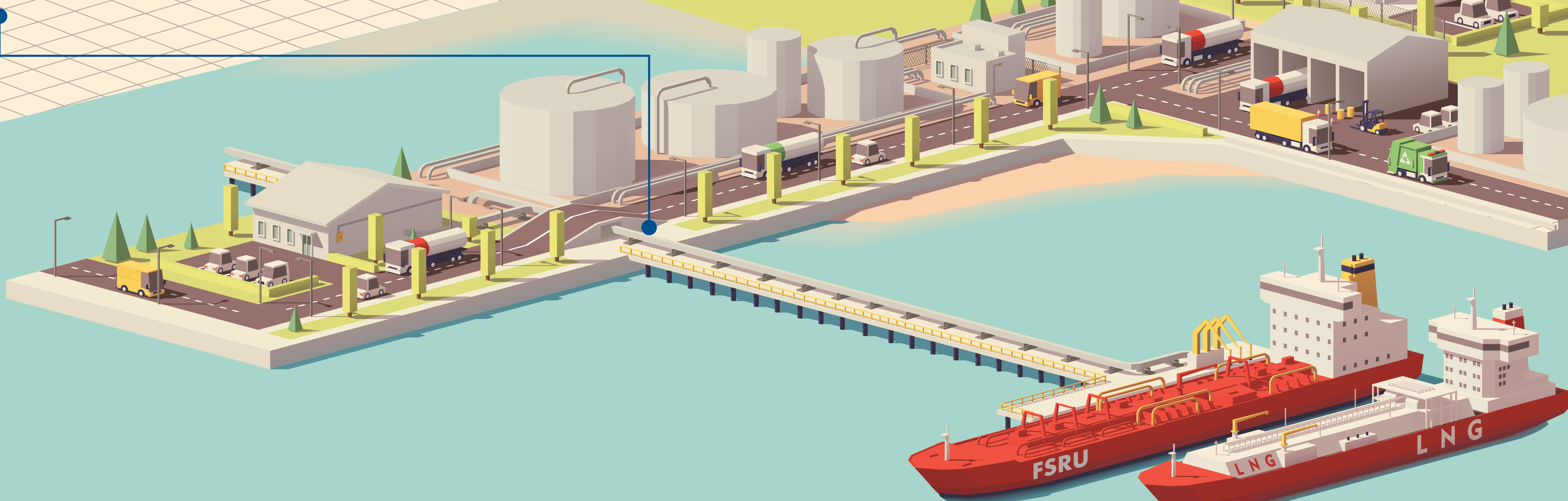
India and Thailand expanded existing LNG plants

Growth in **2019** was driven primarily by new-built terminals in existing LNG import markets: **Bangladesh, Brazil, China, India, and Jamaica**

3 new FSRUs

Bangladesh, Brazil, and Jamaica

120.4 MTPA of new regasification capacity under construction as of February 2020



6.0 LNG Receiving Terminals

Global LNG regasification capacity reached 821 MTPA as of February 2020 and is expected to continue its positive growth trajectory as liquefaction capacity gets added to meet growing demand. Growth in 2019 was driven primarily by new-built terminals in existing LNG import markets, including Bangladesh, Brazil, China, India, and Jamaica. As of February 2020, no new importer added regasification capacities[1] since new importers, Bangladesh and Panama, added regasification capabilities in 2018.

The majority of additions in global receiving terminal capacity in 2019 came from Asian markets, particularly India, affirming the region's stand-out growth. New built terminals in these areas remain primarily shore-based. However, floating regasification terminals are on the rise as well, with the startup of three new FSRUs in Bangladesh, Brazil, and Jamaica in 2019. Turkey's Etki terminal also expanded its regasification capacity by chartering a replacement FSRU with larger receiving capabilities.

In the near term, existing import markets are expected to see regasification capacity additions continue to increase, particularly in Asia, where the receiving capabilities in China and India are expected to expand to support growing LNG demand. A number of new LNG importers will also significantly contribute to regasification capacity growth, including the Philippines, El Salvador, Ghana, Cyprus, Croatia and Vietnam, all of which are in the process of constructing their first LNG import terminal to come online within the next two to three years. Several other new markets have proposed additional regasification capacity, including Myanmar, Cote d'Ivoire, Morocco and Germany. However, many of these markets have experienced delays in project development due to various challenges such as securing financing and navigating regulations related to infrastructure development.

Gibraltar LNG Regasification Terminal - Courtesy of Shell

[1] Excludes Russia's Kaliningrad terminal as it did not receive any cargoes after it was commissioned in January 2019. The terminal's FSRU was chartered out as an LNG carrier through December 2019. Bahrain's first LNG receiving terminal is also excluded as it has yet to discharge any cargoes following technical commissioning in January 2020.

6.1. OVERVIEW

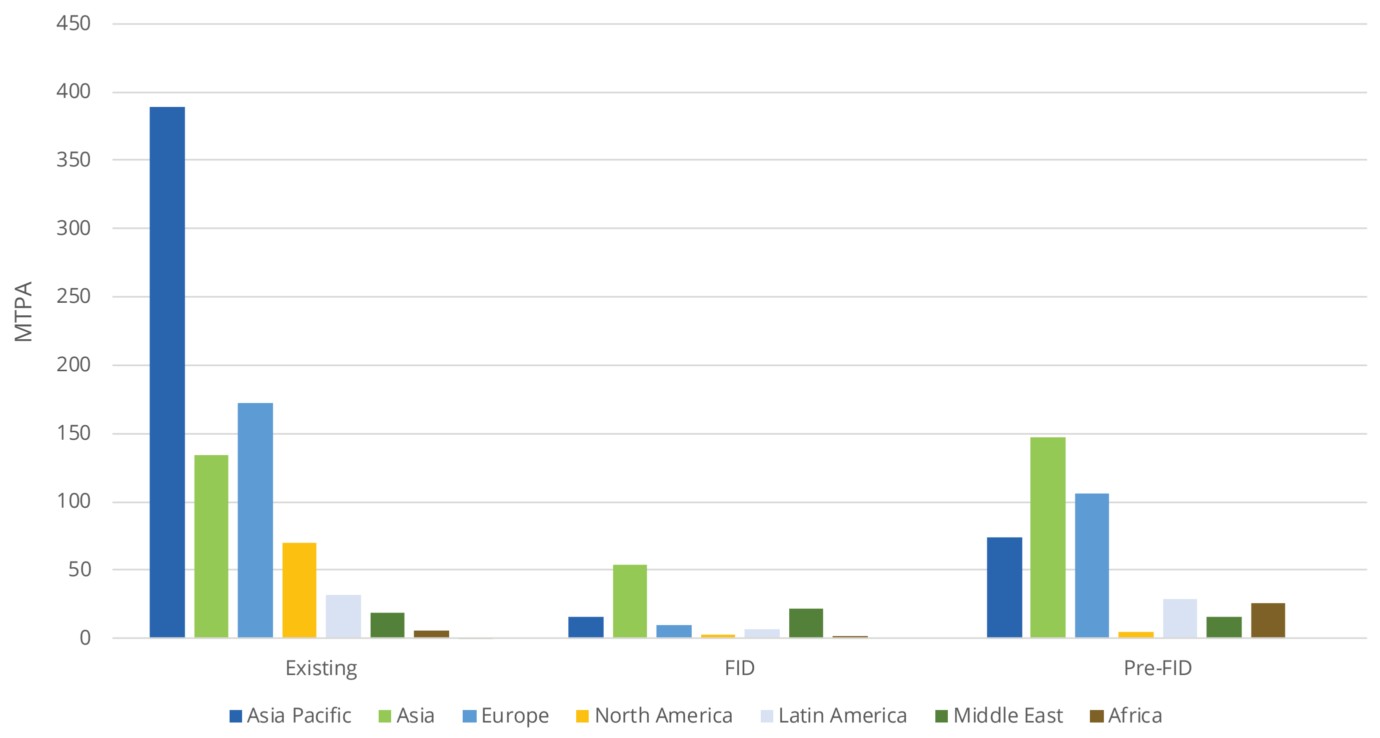
821 MTPA

Total LNG Regasification Capacity Across 37 Markets, Feb 2020

As of February 2020, total LNG regasification capacity in the global market was 821 MTPA across 37 markets[2], thanks to the addition of six new terminals and three expansions at existing terminals between 2019 and February 2020. Of the existing LNG markets, Bangladesh, Brazil, China, India, and Jamaica together built seven new terminals. Also, both India and Thailand successfully expanded existing LNG receiving plants, contributing to additional growth in global regasification capacity. 23.4 MTPA of receiving capacity was added in 2019, with the greatest addition of 5.0 MTPA from a new onshore terminal in India. Floating regasification projects also added slightly more capacity to the global LNG market than onshore regasification facilities despite having fewer terminals constructed.

The Asia and Asia Pacific[3] regions contributed the greatest amount of regasification capacity to the global market and are anticipated to continue to post positive growth through capacity expansions in both existing and new markets. The expansion of regasification capacity in North America has been limited as domestic gas production has accelerated in recent years. In addition to Sabine Pass and Cove Point, which have been operating notionally as bi-directional import/export facilities, a number of other North American import terminals have been or are currently being converted to liquefaction export facilities, including Elba Island, Freeport, and Cameron. FSRUs have continued to play an important role in equipping new markets with regasification capacity, as seen in Asia and Latin America. Following the addition of its first floating regasification terminal last year, Bangladesh successfully expanded its capacity by commissioning another FSRU project in 2019. FSRUs have proven to be a quick approach for new markets to access the global LNG trade, given the availability of pipeline and offloading capabilities. On the other hand, established LNG importers, such as China and South Korea, have expanded their regasification capacities through the construction of onshore regasification terminals, which is a stable long-term solution and allows for future storage expansion.

Figure 6.1: LNG Regasification Capacity by Status and Region, as of February 2020



Source: Rystad Energy

[2] The total number of markets excludes those with only small-scale (<0.5 MTPA) regasification capacity such as Finland, Malta, Norway, and Sweden. It includes markets with large regasification capacity that only consume domestically-produced cargoes, such as Indonesia.
[3] Please refer to Chapter 8: References for an exact definition of each region.

6.2. RECEIVING TERMINAL CAPACITY AND GLOBAL UTILISATION

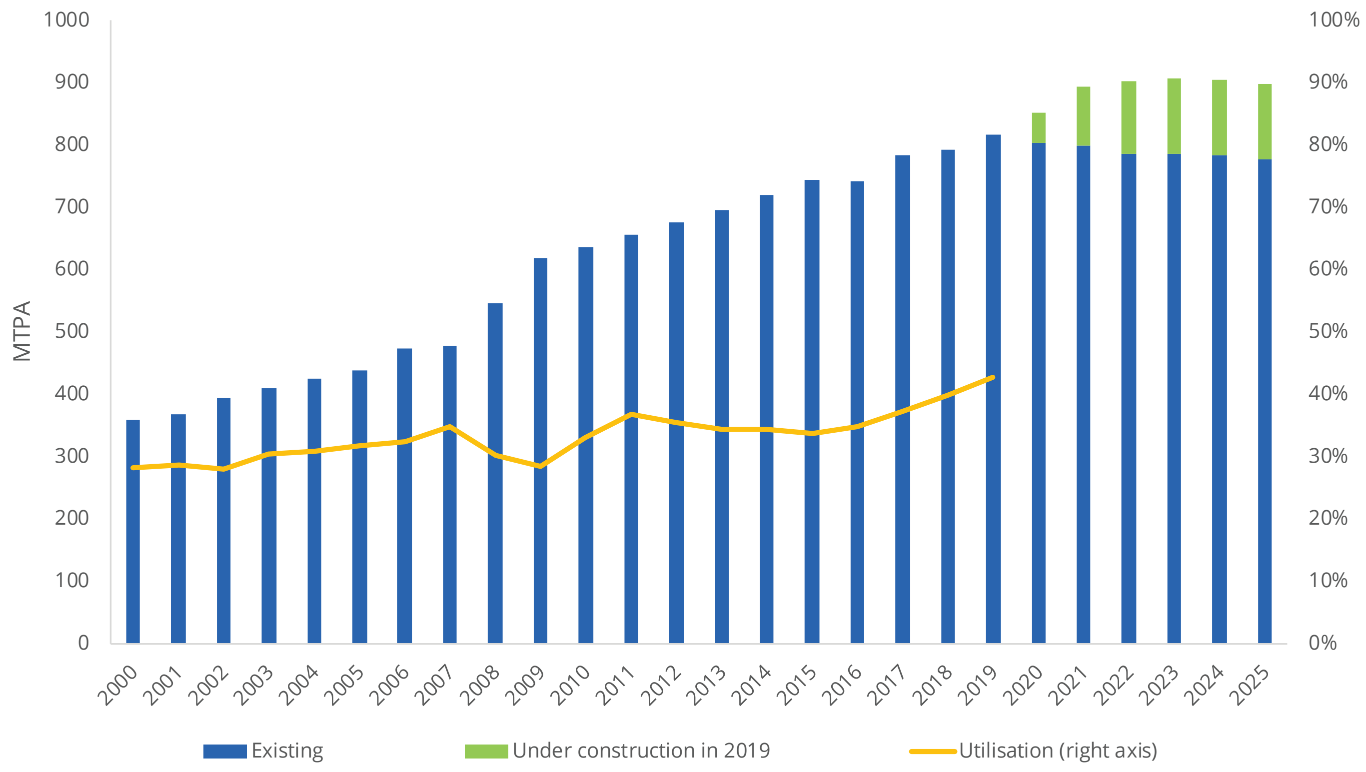
23.4 MTPA

Net Regasification Capacity, Added in 2019

In 2019, 23.4 MTPA[4] of net regasification capacity was added globally. Compared to 2018, when net global LNG receiving capacity grew by 8.0 MTPA, this is a considerably higher growth rate. The number of global LNG importers has grown steadily in the past decade, adding one to two new markets most years. As seen in Egypt in 2015 and in Bangladesh in 2018, FSRUs are playing an increasingly important role in enabling new importers to access LNG supply at a faster rate, driving larger trade flows.

Six new regasification terminals commenced operations in 2019, representing 17.4 MTPA of regasification capacity. Three of these terminals are onshore facilities completed in Asia, with two in China (Fangchenggang and Shenzhen Gas), and the other in India (Ennore). The remaining three new terminals are floating storage and regasification units (FSRUs) located in Bangladesh (Moheshkhali (Summit Corp)), Brazil (Sergipe) and Jamaica (Old Harbour, previously only had a small-scale FSU). Jamaica's new floating terminal — the first of its kind in the Caribbean — was officially commissioned in July 2019 as an import facility to supply new gas-fired power plants in the region. Russia — the world's second largest natural gas producer – commissioned its first LNG import facility in Kaliningrad in early 2019. However, it has yet to reach commercial operations as of early 2020. The send-out capacity of Kaliningrad terminal was excluded from global regasification capacity in 2019 as the terminal had not received any cargoes since its commissioning and was chartered out as an LNG carrier through December 2019.

Figure 6.2: Global Receiving Terminal Capacity, 2000-2020[5]



Source: Rystad Energy

[4] 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 IGU World LNG Report – 2019 Edition.
[5] The above forecast only includes projects sanctioned as of February 2020. 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.

In addition, three expansion projects were completed at existing regasification terminals in 2019. One expansion project, adding 1.5 MTPA at Thailand's Map Ta Phut terminal, came online in January 2019. India's Dahej terminal added 2.5 MTPA of capacity with the second expansion project at the terminal, increasing its total regasification capacity to 17.5 MTPA. Meanwhile, Turkey's Etki terminal added 2 MTPA of capacity. This was achieved through the replacement of a 3.7 MTPA capacity FSRU with a larger vessel, increasing the terminal's regasification capacity to 5.7 MTPA. Combining the 17.4 MTPA added via new terminals and the 6.0 MTPA added through expansion projects, total regasification capacity added globally in 2019 reached 23.4 MTPA.

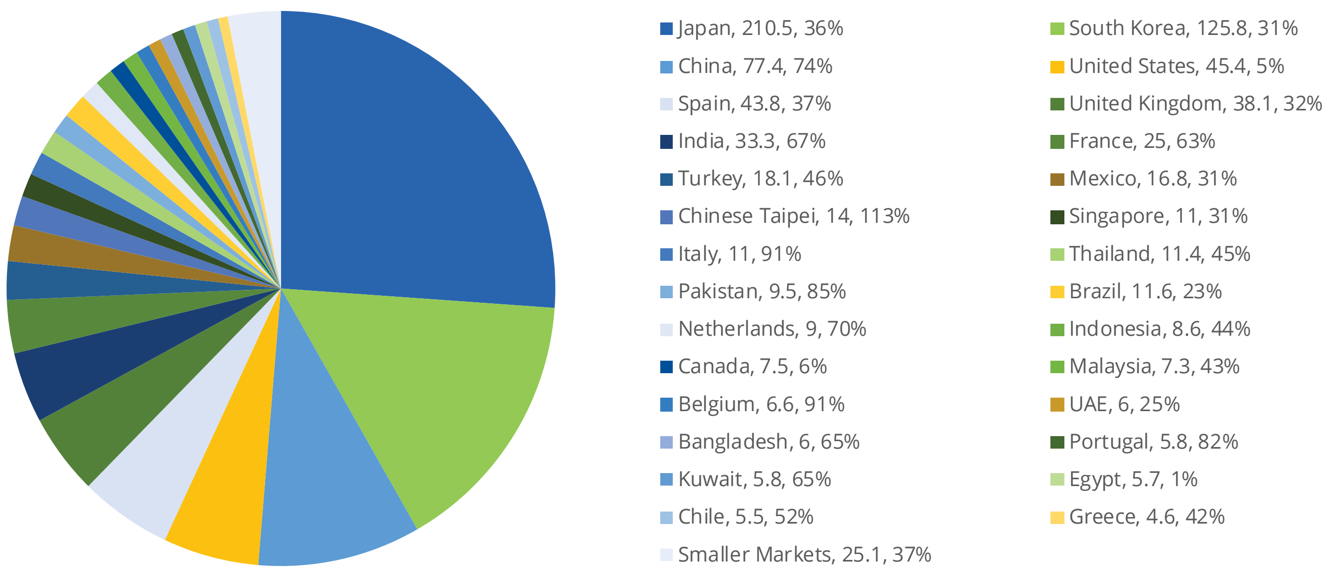
Kuwait's Mina Al-Ahmadi terminal ended the charter of the Golar Igloo FSRU in 2019, after extending it to November. Kuwait National Petroleum Company (KNPC) has since awarded Golar Partners another two-year charter of the Golar Igloo, to provide continued LNG storage and regasification at Mina Al-Ahmadi beginning in March 2020.

One new terminal came online in January 2020, adding 5.0 MTPA at India's Mundra terminal. Apart from this newly operational project, 120.4 MTPA of new regasification capacity was under construction as of February 2020. This includes 14 new onshore terminals, 12 FSRUs, and seven expansion projects at existing receiving terminals. Notably, six out of seven capacity expansion projects are being carried out at onshore terminals located in Asia and Asia Pacific regions. Eight out of 33 terminals under construction (including terminals with expansion projects) will be built in new markets without existing regasification capacity, such as Ghana, the Philippines, El Salvador, Cyprus, Croatia and Vietnam. In October 2019, construction commenced on the Thi Vai LNG terminal after funding was secured for the first phase of the project to import natural gas into Vietnam. In December 2019, Cyprus signed a contract with a Chinese consortium for the construction of the market's first LNG regasification terminal. Through the construction of six floating and two onshore terminals, these eight new markets will add 17.7 MTPA of regasification capacity to the global LNG market. China has six new onshore terminals under construction, in addition to four expansion projects, while India is building four new terminals and executing one expansion project at an onshore terminal. Additional terminal construction and regasification capacity expansion projects are underway in Brazil, Chinese Taipei, Indonesia, Japan, Kuwait, Mexico, Poland, Turkey and the United States (Puerto Rico).

Average regasification utilisation levels across global LNG markets reached 43%[6] in 2019, a 3% jump from 2018. Regasification terminal capacity generally exceeds liquefaction capacity in order to meet peak seasonal demand and secure supply. Growing natural gas demand has supported the steady growth seen in the average global regasification utilisation, in spite of the 23.4 MTPA net regasification capacity addition in 2019. On a monthly basis, utilisation rates across global regasification terminals fluctuated throughout the year, reaching the highest utilisation during the peak period between November to January. The cyclical fluctuation in utilisation rates is likely a result of seasonality in LNG demand, as well as the geographical distribution of LNG importers, since winter months in the Northern Hemisphere drive the greatest demand for LNG regasification.

6.3. RECEIVING TERMINAL CAPACITY AND UTILISATION BY MARKET

Figure 6.3: LNG Regasification Capacity by Market (MTPA) and Annual Regasification Utilisation, 2019[7]



Source: Rystad Energy

[6] Based on Rystad Energy trade data.
[7] "Smaller Markets" includes (in order of size): Argentina, Jordan, Poland, Lithuania, Colombia, Israel, Dominican Republic, Russia, Jamaica, Panama. Regasification utilisation figures are based on 2019 Rystad Energy trade data and prorated regasification capacity based on terminal start dates in 2019. Prorated capacity in 2018 is displayed in this graph.

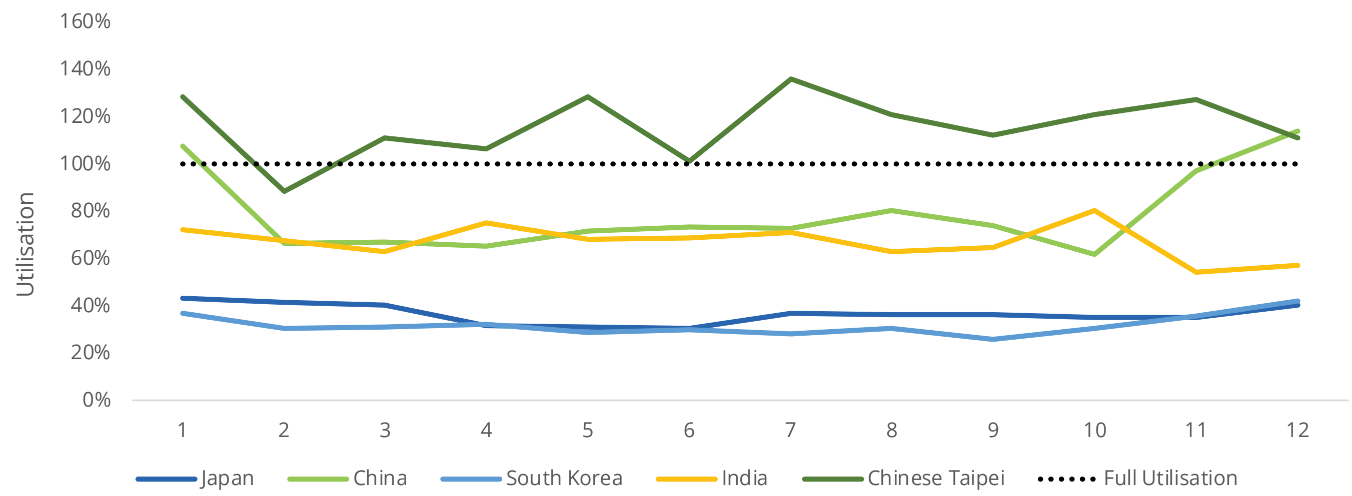
Japan 210.5 MTPA
World's Largest
Regasification Capacity

Japan has the world's largest regasification capacity of 210.5 MTPA as of February 2020, representing 25% of global regasification capacity. Despite not adding any regasification capacity in 2019, Japan is anticipated to continue expanding its importing abilities through new terminals and expansion projects. Construction of a new 0.5 MTPA receiving terminal at Niihama on the northern coast of Shikoku in western Japan has begun and is due for completion in February 2022. At year-end 2019, Japan's regasification utilisation reached 36%[8], slightly down from 39% in 2018.

As the world's third largest LNG importer behind Japan and China, South Korea held its position as the second largest regasification capacity market globally in 2019. With six existing import terminals, South Korea contributed 125.8 MTPA of regasification capacity to the global LNG market in 2019. South Korea's utilisation rate also dipped slightly to 31%[9], as LNG import is set to temporarily decrease owing to the start-up of new long-planned nuclear and coal-fired power plants.

The growth rate of China's regasification capacity is one of the most rapid among global LNG import markets, driven by increased use of natural gas for power generation. Since China became the world's second largest LNG importer in 2017, China has built nine new terminals between 2017 and 2019, adding a total of 24.1 MTPA of import capacity. In 2019, two new onshore terminals were commissioned, one in January (Fangchenggang LNG) and one in August (Shenzhen Gas LNG), accounting for 1.4 MTPA of regasification capacity combined. In terms of total regasification capacity, China is the third largest market in the world with 77.4 MTPA of nameplate capacity by the end of 2019. With six new onshore projects under construction and four existing terminals undergoing expansion, China is set to add up to 28.9 MTPA of regasification capacity by 2023. China's strong regasification growth rate is expected to continue, closing the gap with South Korea and Japan. China's regasification utilisation rate was 74%[10] in 2019, a steady increase since 2016. While relatively high spare capacity above 30% was experienced in summer months, utilisation rates at China's import terminals were exceptionally high during winter periods, peaking at 114% in December 2019 (see Figure 4). China's capacity expansion projects are likely to ease the tightness in its import value chain during peak periods, provided that newly-built terminals are sufficiently connected to the local grid to support send-outs. As a temporary measure, some LNG buyers have started trucking LNG from the regasification terminals to key demand centers, as they wait for infrastructure to be built or become accessible. However, while LNG demand in China is set to rise on the back of strong governmental support for increased consumption of the relatively cleaner fuel, LNG imports may fluctuate in response to economic conditions, coal use, pipeline imports and domestic gas production.

Figure 6.4: Monthly 2019 Regasification Utilisation by Top Five LNG Importers



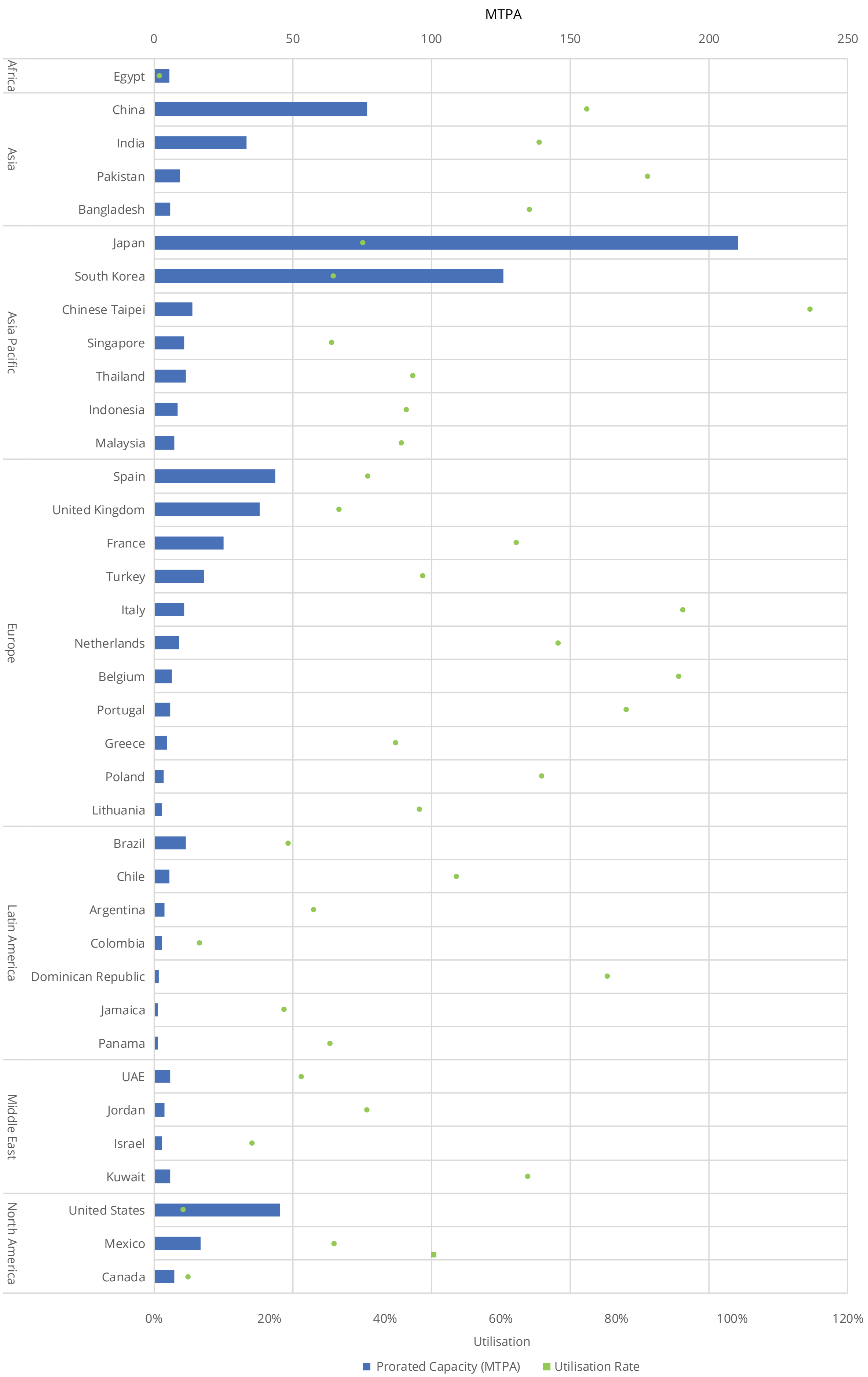
Source: Rystad Energy, Refinitiv

India is another market which has experienced strong regasification capacity growth. Despite contributing only 34.5 MTPA of total global regasification capacity in 2019, India has another 24.0 MTPA of regasification capacity under construction as of February 2020. A new 5.0 MTPA onshore terminal (Ennore LNG) was commissioned in March 2019, while an existing import terminal (Dahej) was expanded by 2.5 MTPA in June 2019. As of the end of 2019, India had five operational regasification terminals in total. In January 2020, the terminal at Mundra received its commissioning cargo, adding 5.0 MTPA of regasification capacity. Another 4.0 MTPA of regasification capacity is expected to be operational by the first quarter of 2020 at Jaigarh, marking India's first FSRU-based terminal. India's second floating terminal (Jafrabad FSRU) is due to come online in mid-2020, adding another 5.0 MTPA of regasification capacity. In August 2019, construction work commenced at the Chhara LNG terminal. With the relatively rapid addition of 7.5 MTPA of regasification capacity at Ennore and Dahej terminals last year coupled with muted LNG import growth, India's utilisation rate dropped to 67% in 2019, a decrease from 82% in 2018.

Chinese Taipei registered the highest regasification utilisation in 2019 at around 113%; the market has typically received higher volumes than its announced regasification capacity. 2019 saw Chinese Taipei's terminals working above its full utilisation rate all year round, with the exception of February 2019. Chinese Taipei is also the fifth largest importer of LNG, partly a result of its clean energy plan to phase out coal and nuclear power in electricity generation. To support the boost in LNG imports, Chinese Taipei is adding regasification capacity at its existing terminal (Taichung), which is currently under construction and is set to come online in 2020. Plans are in place to build a third LNG terminal here, which is expected to be commissioned in 2024. Chinese Taipei's regasification utilisation rate is likely to remain elevated in the near term.

[8] Based on Rystad Energy trade data.
[9] Based on Rystad Energy trade data.
[10] Based on Rystad Energy trade data.

Figure 6.5: Receiving Terminal Import Capacity and Regasification Utilisation Rate by Market in 2019



Source: Rystad Energy

European markets account for approximately 20% of total global regasification capacity. However, regasification capacity additions have been relatively slow in these markets, with the exception of Turkey, which has shown regasification capacity growth in recent years. Following the commissioning of a new 5.4 MTPA regasification terminal (Dortyol FSRU) in 2018, Turkey completed the replacement of an existing vessel with a larger-capacity 5.7 MTPA FSRU at the Etki terminal in July 2019, expanding the terminal's total send-out capacity by 2 MTPA. Three other European markets have regasification projects currently under construction as well. Due for commissioning in 2021, the Krk project — a 1.9 MTPA FSRU-based terminal which began construction in April 2019 — will allow Croatia to access the global LNG market as a new importer. On the other hand, progress on the construction of the Gothenburg terminal in Sweden has been halted following the government's denial of a final permit based on climate concerns in October 2019. Following a significant increase in LNG import levels, 2019 saw a surge in Europe's regasification utilisation rates to an average of 60% from 35% in 2018. While Europe's LNG import terminals have seen low utilisation rates in the past five years, LNG imports to the region grew steadily in 2018 and rose sharply in 2019. In total, European markets imported 85.9[11] MT of LNG in 2019 (net of re-export), which is a 75.6%[12] increase compared to Europe's LNG import levels in 2018. Some of the highest utilisation rates were observed in terminals located in Belgium, Portugal and Italy. Over the past year, European markets absorbed most of the new LNG supplies from US and Russia, largely due to insufficient growth in Asian LNG demand through the summer months and low prices in Asia. Europe's liquid market and slightly higher netback (due to the narrowing of the spread between Asian spot and European prices) attracted new LNG supplies to the region. The over-supply situation at European terminals also drove very high levels of storage tank utilisation rates during the past year. At the six terminals of the Spanish gas system, storage capacity had an average utilisation rate of 77% and peak rate at 99% during 2019.

Although the third highest in terms of global regasification capacity, the United States has low levels of terminal utilisation rates. Utilisation rates averaged 5% in 2019, primarily driven by LNG imports to Puerto Rico. The Penuelas regasification terminal experienced high volumes of LNG imports in recent years, reaching a terminal utilisation rate of 119% in 2019. Puerto Rico has plans to add regasification capacity, with their second FSRU-based terminal in San Juan expected to come online by 2020. Excluding the Puerto Rico terminal and Exelon's Everett Massachusetts LNG facility, only several other US terminals received low volume LNG cargoes between 2018-2019, likely to be used as tank cooling supplies in relation to the addition of liquefaction capacity to existing regasification terminals, which will normally function as bidirectional facilities. As of February 2020, the six active regasification terminals in the US have a combined import capacity of 45.4 MTPA. Given the United States' large-scale domestic production of shale and tight gas resources, the US is likely to further reduce LNG imports and prioritise the construction of LNG export over import terminals.

While still a region with relatively little regasification capacity at 32.1 MTPA, Latin America is expected to add another 6.6 MTPA by 2021 through the construction of new FSRU-based terminals in existing (Brazil) and new markets (El Salvador). Brazil's Sergipe terminal saw the unloading of its first commissioning cargo at its Golar Nanook FSRU in April 2019, and its second commercial cargo in the first quarter of 2020. An upcoming terminal Brazil (Port of Acu) is expected to import LNG cargoes in 2020, once the deployed FSRU arrives and is commissioned at its designated ports. The Acajutla LNG project in El Salvador, which began construction in January 2019, involves an offshore FSRU, underground natural gas pipeline and three substations and is expected to be commissioned in 2021.

Notably, Egypt's regasification utilisation rate has fallen from 23% in 2018 to 1% in 2019 since it halted its LNG imports in 2018. This is the result of Egypt's rapidly growing domestic production from recently discovered gas fields, such as Zohr. As of the end of 2019, Egypt has a remaining 5.7 MTPA of regasification capacity following the departure of its chartered FSRU at the Ain Sokhna terminal in October 2018.

Two interesting new LNG import projects in their stages of development are the Kuwait Al Zour LNG Import Terminal and the nearby Bahrain LNG Terminal, which has completed technical commissioning but have yet to discharge cargoes.

The Al-Zour LNG Import Terminal Project includes the construction of a regasification facility, eight LNG storage tanks with a capacity of 225,000 cubic metres (cm) each, and marine facilities, including two marine jetties and berthing facilities for loading. The project will also include other components, such as 14 HP pumps, boil-off gas (BOG) and flare facilities. Once fully operational, the facility is expected to produce approximately 22 million metric tonnes (MMT) of natural gas a year and will have a storage capacity of 1.8 million cm of LNG. The regasification capacity of the terminal will be 30 billion cubic metres a day (bcm/d). This is most likely the largest greenfield LNG import terminals ever developed.

The Bahrain LNG Terminal, although nominally an FSU based terminal, is being developed on a build-own-operate-transfer (BOOT) basis over a 20-year period beginning in July 2018 and will be handed over to the Government of Bahrain at the end of the BOOT period. The LNG terminal is being constructed at an offshore location 4.3 km away from the existing breakwater at the Khalifa Bin Salman Port (KBSP). It will have a production capacity of 800 million standard cubic feet a day. Plans for the site include an offshore jetty and breakwater to receive LNG shipments, as well as a floating storage unit (FSU) and a regasification platform. It will be linked to underwater and surface gas pipelines from the platform to shore. Onshore infrastructure will include a gas receiving plant and a nitrogen production facility. Teekay LNG will supply a floating storage unit (FSU) by converting a 174,000 cm LNG carrier.

Pyeongtaek LNG Terminal - Courtesy of Kogas

[11] GIIGNL
[12] GIIGNL

Receiving Capacity	New LNG onshore import terminals	New LNG Offshore terminals	Number of regasification markets
+23.4 MTPA Net growth of global LNG receiving capacity	**+3** Number of new onshore regasification terminals	**+3** Number of new offshore LNG terminals	**37** Markets with regasification capacity at end-2019
Net nameplate regasification capacity grew by 23.4 MTPA from 791.6 MTPA at end-2018 to 815.7 MTPA in end-2019. Regasification addition at new terminals reached 17.4 MTPA while expansion projects amounted to 6.0 MTPA.	New onshore terminals were added in India (Ennore), China (Fengchenggang and Shenzhen Gas). Two expansion projects at existing onshore terminals were completed in India (Dahej) and Thailand (Map Ta Phut). India's Mundra terminal imported its commissioning LNG cargo in January 2020.	Three[13] FSRUs came online in 2019, in Bangladesh (Moheshkhali (Summit Corp)), Jamaica (Old Harbour) and Brazil (Sergipe). Turkey's Etki terminal replaced its existing FSRU with a new unit with larger regasification capacity in 2019.	The number of markets with regasification capacity remained at 37 at end-2019.

6.4. RECEIVING TERMINAL LNG STORAGE CAPACITY

65 Million Cubic Meters (mmcm)

Global Storage Capacity

Storage capacity at global receiving terminals has climbed steadily with the construction of new LNG terminals and the expansion of existing facilities. Global storage capacity neared 65 million cubic meters (mmcm) through the addition of seven new receiving terminals and three expansion projects in 2019. The average storage capacity for existing terminals in the global market was around 430 thousand cubic meters (mcm).

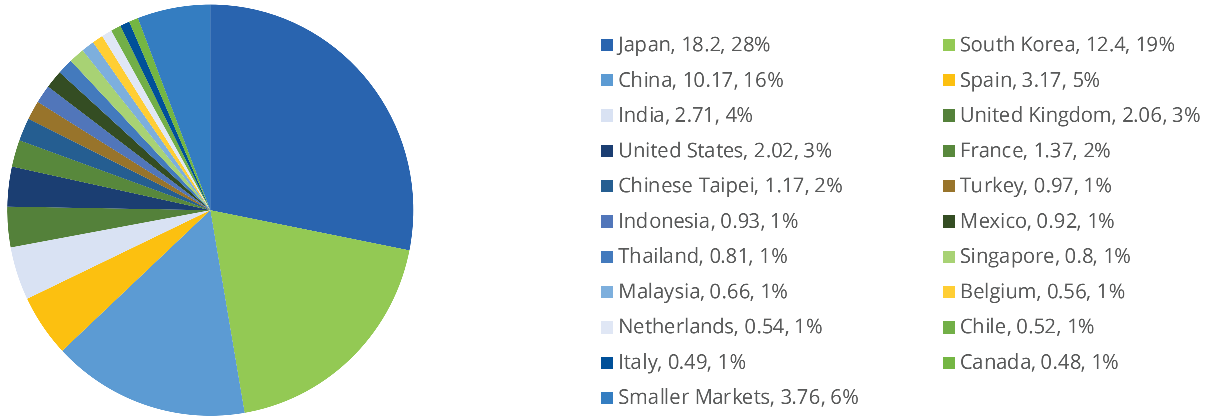
Receiving terminals with higher regasification capacity are often equipped with large storage capacity. Similar to the geographical spread in regasification capacity, over 50% of the LNG market's total existing storage capacity is contained in terminals located in Japan, South Korea and China, ranging from 0.01 to 3.36 mmcm in size. Asian and Asia Pacific markets have the highest share of global storage capacity, as operators in these regions rely on large storage capacity to secure supply and enhance flexibility, particularly given Asia's seasonal demand and in certain markets, the lack of adequate connectivity to gas infrastructure. Additionally, Japan, South Korea and China have limited gas storage options available outside of LNG terminals.

New terminals and project expansions have increased natural gas storage capabilities by 1.40 mmcm in 2019. The largest increase in storage capacity (0.34 mmcm) was added in India, through the addition of the Ennore terminal and expansion project at Dahej terminal. China followed closely, adding a total of 0.25 mmcm of storage capacity, through the construction of two new terminals. The installation of FSRUs added 0.12 mmcm of storage capacity at Jamaica's Old Harbour terminal, 0.17 mmcm at Brazil's Sergipe and 0.13 mmcm at Bangladesh's Moheshkhali terminal. Turkey's Etki terminal storage capacity grew slightly by 0.03 mmcm through its replacement FSRU. Onshore terminals saw storage capacity additions of 0.17 mmcm at Thailand's Map Ta Phut terminal through its recently completed expansion project. Belgium's Zeebrugge terminal commissioned its fifth storage tank in late December 2019, expanding the terminal's storage capacity by another 0.18 mmcm.

Notably, the development of global storage capacity shows signs of divergence. In established LNG markets, the continued construction of new onshore terminals supports the growth of storage capacity. In newer markets, however, the frequent deployment of FSRUs translates into substantially lower storage capacity. As of early 2020, average storage capacity at onshore terminals (0.48 mmcm) is observed to be larger than that of offshore terminals (0.16 mmcm).

[13] Excludes Russia's Kaliningrad terminal as it did not receive any cargoes after it was commissioned in January 2019. The terminal's FSRU was subsequently chartered out as an LNG carrier through December 2019.

Figure 6.6: LNG Storage Tank Capacity by Market (mmcm) and % of Total, as of February 2020[14]



Source: Rystad Energy

6.5. RECEIVING TERMINAL BERTHING CAPACITY

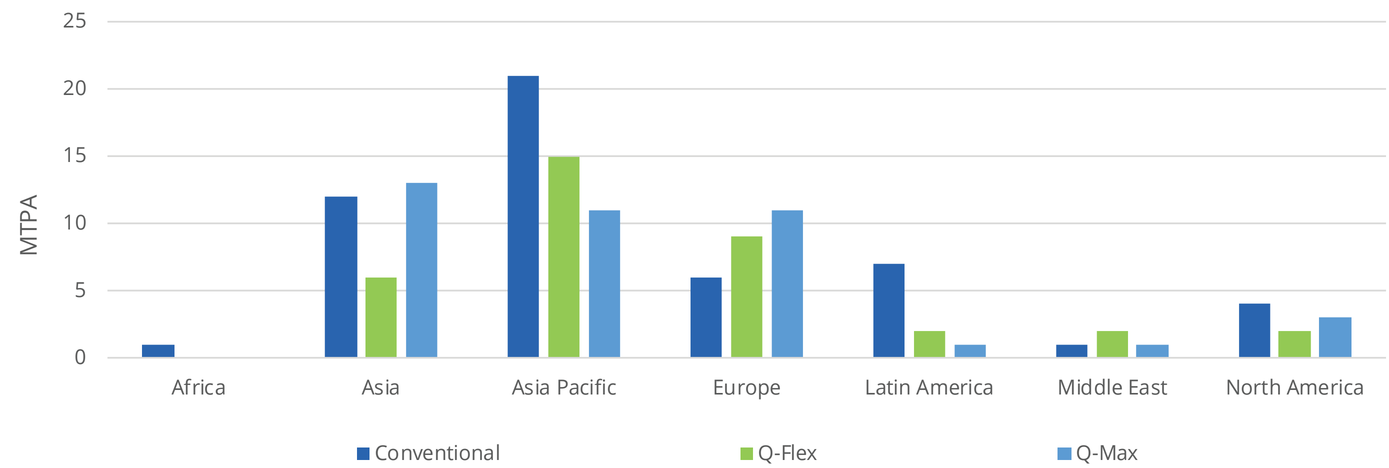
125,000 - 175,000 Cubic Meters

Conventional-Sized Ships Capacity

The berthing capacity at a regasification terminal determines the type of LNG carriers it can accommodate. Traditionally, regasification terminals are built to handle conventional-sized ships, which are predominantly between 125,000 to 175,000 cubic meters in capacity. With the increased utilisation of Q-Class carriers and the global increase in storage capacities, a number of high-demand markets are scaling up their maximum berthing capacity at existing and new-built onshore terminals to receive larger ships. However, in new markets that typically deploy FSRUs or small-scale regasification terminals, terminals have smaller berthing capacities.

As the largest LNG tankers in existence, Q-Flex and Q-Max vessels can carry approximately 210,000 cubic meters and 266,000 cubic meters of LNG respectively, almost 80% more than conventional LNG carriers. As of early 2020, 40 operational regasification facilities have the capacity to receive Q-Max and Q-Flex vessels. Of these 40 terminals, up to 60% are located in the Asia or Asia Pacific regions, while the Middle East and Latin America have one such terminal each. Slightly smaller in capacity, Q-Flex vessels can be berthed at an additional 36 terminals, which are also primarily located in Asia or Asia Pacific regions. The remaining 52 terminals are equipped with sufficient berthing capacity to handle the majority of modern LNG vessels, which are generally below 200,000 cubic meters. Notably, onshore terminals accounted for 93% of terminals capable of handling Q-Max size vessels, and 55% of FSRUs are deployed at terminals that can only accommodate conventional sized vessels. In 2019, one new terminal capable of receiving Q-Flex vessels was added in Bangladesh.

Figure 6.7: Maximum Berthing Capacity of LNG Receiving Terminals by Region, as of February 2020[15]



Source: Rystad Energy

[14] "Smaller Markets" include (in order of size): Portugal, Pakistan, Poland, Brazil, Bangladesh, Greece, Panama, Russia, Egypt, Colombia, Jamaica, Kuwait, Lithuania, Dominican Republic, Jordan, Jordan, UAE, Argentina, Israel. Each of these markets had less than 0.4 mmcm of capacity as of February 2020.
[15] Terminals that can receive deliveries of more than one size of vessel are only included under the largest size that they can accommodate.

6.6. FLOATING AND OFFSHORE REGASIFICATION

101.2 MTPA

Regasification Capacity Across 24 Terminals, February 2020

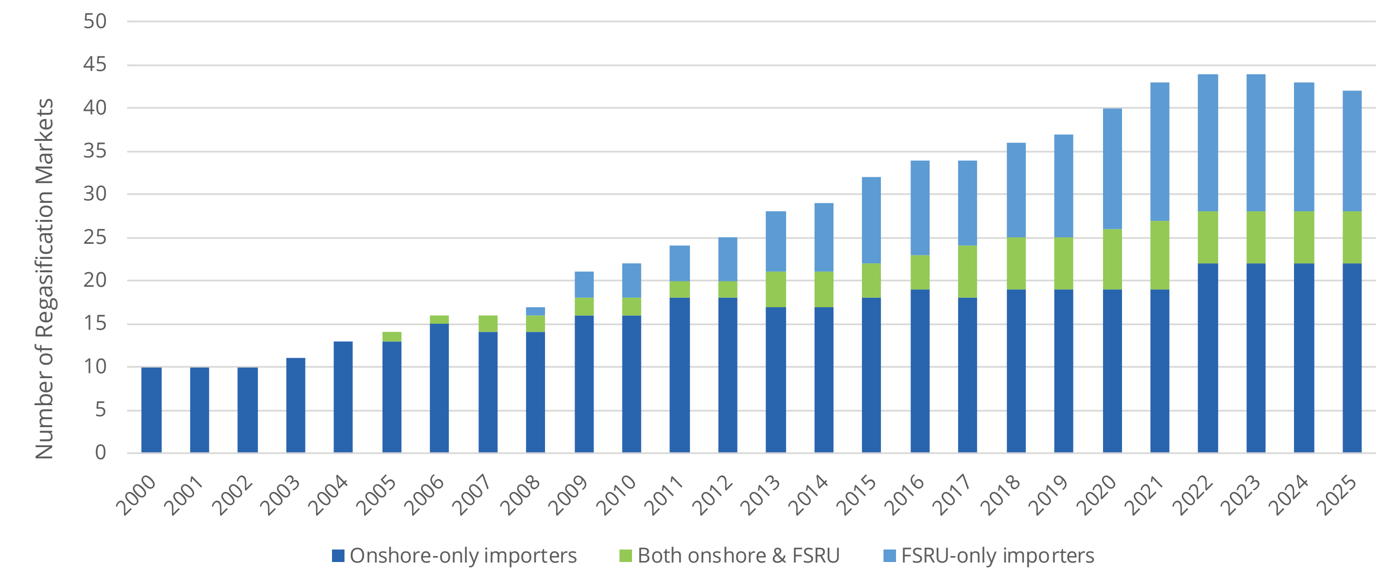
The majority of the existing regasification terminals are land-based, and the ratio of existing onshore to floating regasification terminals as of February 2020 was around 5:1. However, the proportion of floating regasification terminals has grown steadily in recent years, as an increasing number of new FSRU-based projects came online. Floating regasification has grown from a single terminal with 3.8 MTPA of capacity in 2005 to 24 terminals with a combined capacity of 101.2 MTPA as of February 2020. Indeed, three of the six terminals that began operations in 2019 were offshore developments, and 12 of 26 new terminals under construction as of February 2020 are floating regasification projects.

A number of new markets have entered the global LNG trade through the addition of FSRU-based terminals in the past few years, including Bangladesh in 2018. Of the 37 existing LNG import markets as of February 2020, 19 imported LNG with FSRUs, and six of those had onshore terminals as well.

Eight offshore projects are under construction and have announced plans to become operational by the end of 2020, totaling 31.2 MTPA of capacity. Some of these projects are undergoing construction in India, Brazil, the United States (Puerto Rico), Ghana, and Turkey. India will add its first FSRU-based terminal at Jaigarh, equipping it with both onshore and FSRU terminals. In addition, several FSRU projects currently under construction are planned for start-up in 2021. In particular, this would include new import markets such as El Salvador, Croatia and Cyprus. However, not all new importers are utilising floating-based terminals, some new importers, including Vietnam, are building their first regasification terminals as onshore facilities.

Three new floating terminals became operational in 2019[16]: Bangladesh's 3.8 MTPA Moheshkhali (Summit) terminal, Jamaica's 3.6 MTPA Old Harbour terminal and Brazil's 3.6 MTPA Sergipe terminal. Bangladesh's Moheshkhali (Summit) and Jamaica's Old Harbour terminals are the markets' second regasification terminals. Brazil's new FSRU project at Sergipe terminal started commercial operations in early 2020 after the installation and commissioning of its FSRU Golar Nanook in April 2019. Turkey's Etki terminal had its FSRU leave port in July 2019, and started the chartering of a replacement vessel with higher regasification capacity in the same month. With the new FSRU in operations, Turkey's Etki terminal's total regasification capacity expanded to 5.7 MTPA. Following the charter extension on Golar Igloo to the end of 2019, Kuwait's Mina al-Ahmadi terminal has signed a two-year charter for Golar Igloo to provide continued LNG storage and regasification services for the terminal's regasification season, beginning in March 2020 to 2022. As of February-2020, the total global active floating import capacity stood at 101.2 MTPA in 24 terminals.

Figure 6.8: Number of Regasification Markets by Type, 2000-2025[17]

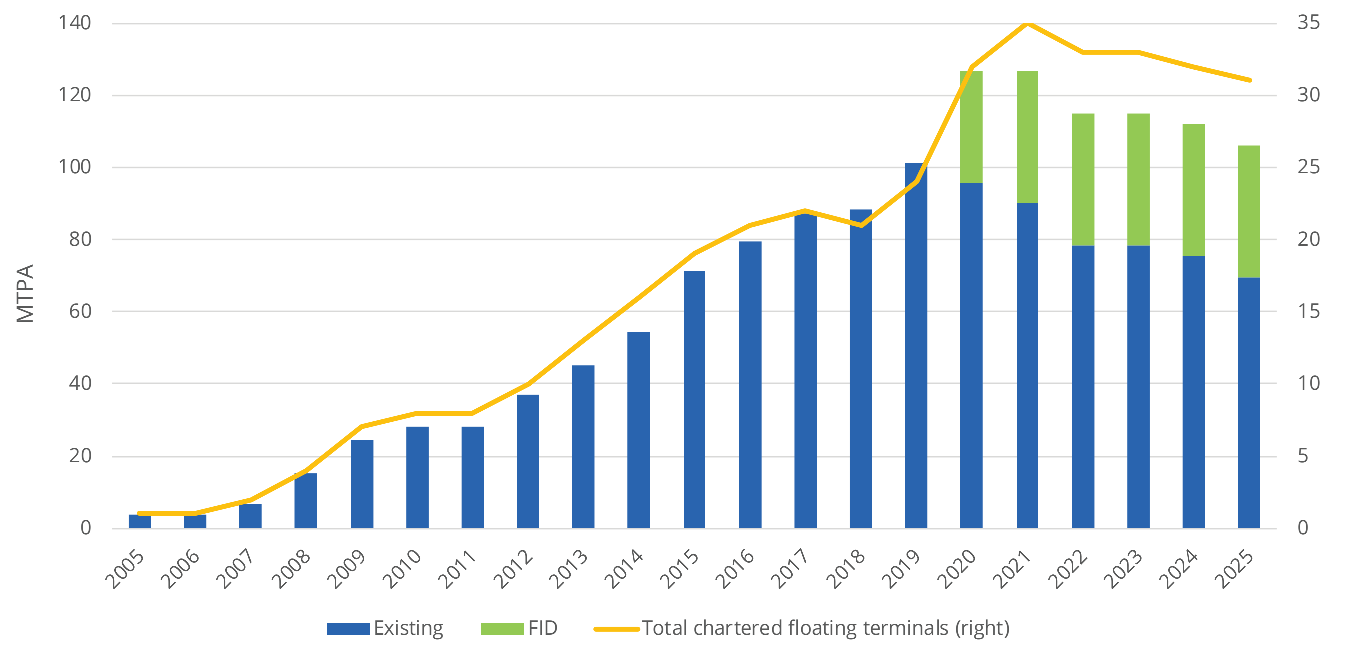


Source: Rystad Energy

[16] Excludes Russia's Kaliningrad terminal as it did not receive any cargoes after it was commissioned in January 2019. The terminal's FSRU was subsequently chartered out as an LNG carrier through December 2019.

[17] The above forecast graph only includes importing markets that had existing or under-construction LNG import capacity as of year-end 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 period.

Figure 6.9: Floating Regasification Capacity by Status and Number of Terminals, 2005-2025[18]



Source: Rystad Energy

Table 6.1: Comparison of Onshore Terminals and FSRUs

Onshore Terminals	FSRUs
Provides a more permanent solution	Allows for quicker fuel switching or complementing domestic production.
Offers longer-term supply security	Greater flexibility in land and port requirements
Greater gas storage capacity	Requires lower capital expenditures (CAPEX)
Requires lower operating expenditures (OPEX)	Depending on location, fewer regulations

The rising prevalence of FSRUs as a storage and regasification solution has demonstrated the potential to deliver a range of benefits often distinct from the onshore alternative. In selecting the concept of a new-built terminal, it is critical for markets to weigh the benefits and drawbacks of each option (FSRU and onshore terminal) against specific market requirements, conditions and constraints. In recent years, FSRUs have enabled several new markets, including Bangladesh, Jordan and Pakistan, to receive their first LNG cargoes in a relatively short time span. FSRUs' shorter construction and delivery time and ease of relocation compared to an onshore terminal can meet potential near-term gas demand surges in a time-efficient manner. This is done by complementing domestic production or accelerating a market's fuel switching process. On average, FSRUs are less CAPEX-intensive than land-based terminals due to the common practice of chartering FSRUs from third parties. As they only require minimal onshore space and construction, the greater flexibility offered by FSRUs make them an attractive option for markets with limited land and port availability.

Onshore terminals, on the contrary, offer a different combination of advantages compared to FSRU. Markets with substantial requirements for storage and regasification capacities can benefit from developing an onshore terminal, which typically supports the installation of larger storage tanks and regasification capacity relative to a floating terminal. Onshore projects are also less exposed to location-dependent risk factors including vessel performance, and potentially longer downtime due to heavy seas or meteorological conditions. As a permanent asset, onshore terminals allow for easier on-site storage and regasification capacity expansions, if required, making them an economical solution for markets that require longer-term supply security.

As of February 2020, there were ten FSRUs with capacity over 60,000 cubic meters on the order book. With several vessels temporarily utilised as conventional LNG carriers and multiple others open for charter at the same time in the past year, near-term floating regasification capacity can likely satisfy demand. However, the FSRU market is anticipated to tighten in the longer term. The number of proposed import projects (including pre-FID terminals) utilising FSRUs has grown significantly in recent years, but over half have yet to sign any charter agreements to secure their vessels. As the global LNG market expands, the strategic importance of being time-efficient and cost-effective in terminal commissioning is set to grow, particularly in new import markets.

[18] The above forecast only includes floating capacity sanctioned as of year-end 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 period.

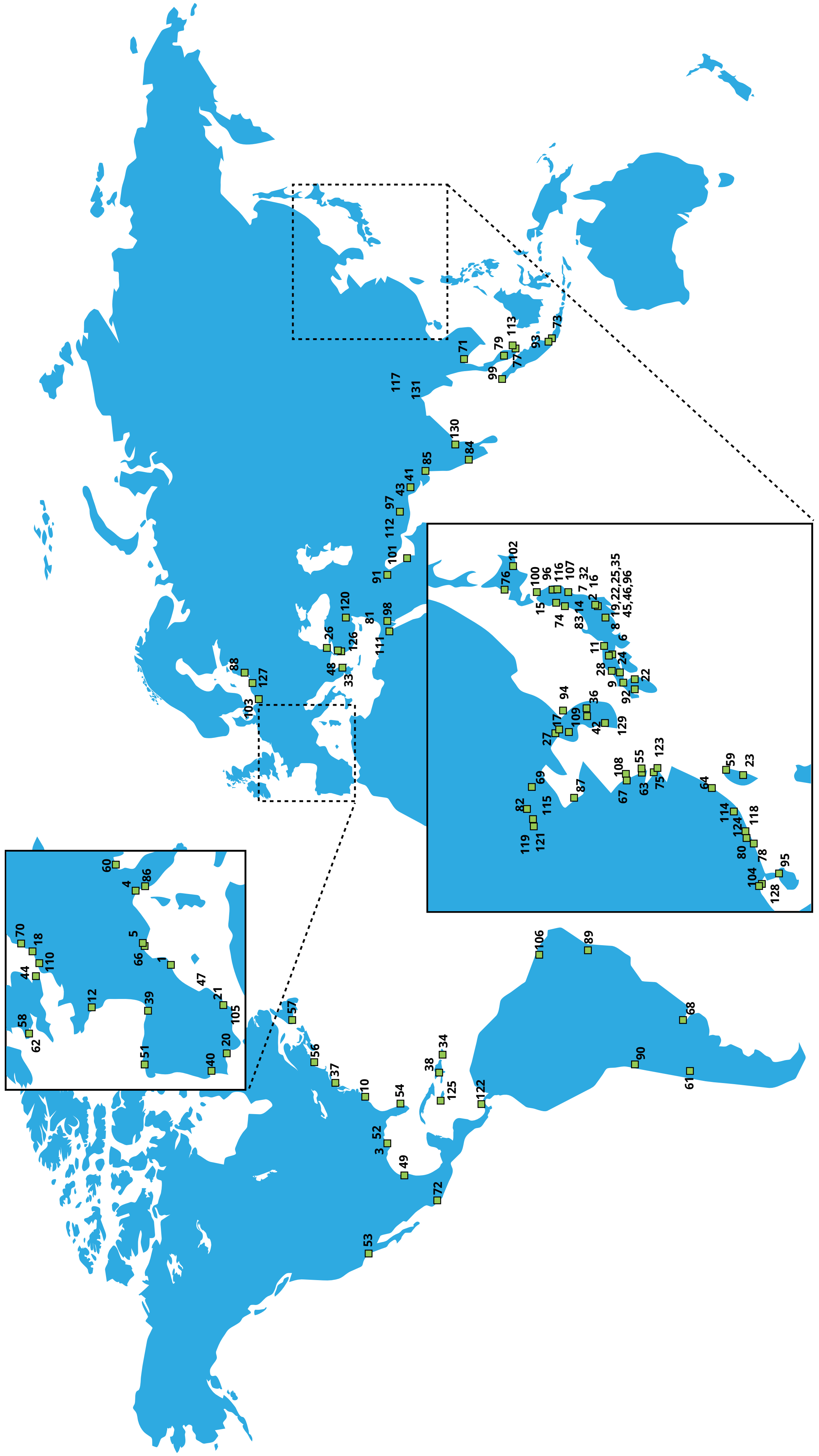


Figure 6.10: Global LNG Receiving Terminal Locations

Note: Terminal Numbers Correspond to Appendix 5: Table of Global LNG Receiving Terminals.
Source: Rystad Energy

6.7. RECEIVING TERMINALS WITH RELOADING AND TRANSSHIPMENT CAPABILITIES

France Re-Exported 0.61 MTPA

Receiving terminals with diversified service offerings have emerged in recent years. Beyond traditional regasification operations, diversified terminals are equipped with additional value-adding services such as reloading, transshipment, small-scale LNG bunkering and truck-loading. Following the rise of terminals with reloading and transshipment capabilities, re-export volume from markets where reloading terminals are located have more than doubled since 2017. Generally, re-exporting activities increase profitability for traders by taking advantage of arbitrage opportunities through LNG trade between regional markets as well as logistical factors within certain markets. For the fourth consecutive year, France re-exported the most cargoes globally in 2019 at 61 MTPA[19], through its terminals in Montoir, Fos Cavaou and Dunkirk. However, France experienced a 1 MTPA[19] decline compared to its re-export volume in 2018. After France, Singapore re-exported the second largest volume of cargoes in 2019 at 4 MTPA[19]. Despite sending out high re-export volumes historically, European markets including Spain, Belgium and the Netherlands have seen a reduction in cargo volumes in recent years. With the decline in global re-export volume, the share of European re-exports in the global LNG market has fallen from 77% in 2018[19] to 58% in 2019[19].

One new market began the re-exporting of LNG cargoes in 2019 — Jamaica. Seeking to position itself as the Caribbean hub for LNG re-export, Jamaica has re-exported around 01 MTPA[19] of LNG cargoes from its new regasification terminal at Port Esquivel in 2019 since its commissioning in late July. France's Dunkirk, which generated its first re-export cargoes in early 2018, has seen a re-export volume of 0.08 MTPA in 2019. Lithuania, which began re-exports within the region in 2017 with small-scale volumes of less than 0.01 MTPA, has experienced a growth in LNG re-exports in 2019, reaching a total of 02 MTPA[19]. As of February 2020, 27 terminals in 16 different markets have reloading capabilities.

Value-adding services including transshipments and bunkering services can be performed at terminals with multiple jetties, such as the Montoir-de-Bretagne terminal in France. Established markets in Europe have terminals such as Gate LNG, Barcelona and Cartagena that are capable of providing this functionality for ships as small as 500 cubic meters. Multiple receiving facilities enhance their infrastructure to provide transshipment, bunkering and truck loading capabilities. Belgium's Zeebrugge terminal has expanded its storage capacity through the construction of its fifth storage tank to support larger transshipment volumes in late December 2019. The Huelva terminal in Spain completed its first LNG bunkering operation from truck to ship in June 2019, and Spain is now offering this service on a frequent basis in several of its ports. Singapore's Jurong terminal completed the modification of its second jetty to receive and reload LNG carriers of between 2,000 cubic meters and 10,000 cubic meters in capacity. The jetty will enable regional small-scale LNG distribution and LNG bunkering services.

Incheon LNG Terminal - Courtesy of KOGAS

[19] GIIGNL

Table 6.2: Regasification Terminals with Reloading Capabilities as of February 2020

Market	Terminal	Reloading Capacity (mcm/h)	Storage (mcm)	No. of Jetties	Start of Re-Exports
Belgium	Zeebrugge	6	560	1	2008
Brazil	Guanabara Bay	1	171	2	2011
Brazil	Bahia	5	136	1	N/A
Brazil	Pecém	1	127	2	N/A
Colombia	Cartagena	0.005	170	1	N/A
Dominican Republic	AES Andres LNG	N/A	160	1	2017
France	Fos Cavaou	4	330	1	2012
France	Montoir-de-Bretagne	5	360	2	2012
France	Dunkirk LNG	4	570	1	2018
France	Fos Tonkin	1	150	1	N/A
India	Kochi LNG	N/A	320	1	2015
Japan	Sodeshi	N/A	337	1	2017
Jamaica	Port Esquivel	N/A	170	1	2019
Mexico	Energia Costa Azul	N/A	320	1	2011
Netherlands	Gate LNG	10	540	3	2013
Portugal	Sines LNG Terminal	3	390	1	2012
Singapore	Jurong	8	564	2	2015
South Korea	Gwangyang	N/A	530	1	2013
Spain	Cartagena	7.2	587	2	2011
Spain	Huelva	3.7	620	1	2011
Spain	Mugardos LNG	2	300	1	2011
Spain	Barcelona LNG	4.2	760	2	2014
Spain	Bilbao	3	450	1	2015
Spain	Sagunto	6	600	1	2013
United Kingdom	Grain	Ship-dependent	960	1	2015
United States	Freeport LNG	2.5	320	1	2010
United States	Sabine Pass LNG	2.5	800	2	2010
United States	Cameron LNG	2.5	480	1	2011

6.8. RISKS TO PROJECT DEVELOPMENT

Regasification Terminal Developers

Often Confront Multiple Difficulties

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 can mitigate the risk of demand variation as they 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. Aggregators and traders can to some extent help take on these risks and lower the perceived liabilities to the bank. Financing challenges may in some cases derive from regulatory constraints relying mostly on public investment by state-owned enterprises and impeding the flows of private capital into the sector.

Regulatory and fiscal regime

New regasification terminals can face significant delays in markets with complicated government approval processes or lengthy permit authorisation 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. A transparent and stable regulatory framework which incorporates a proper risk-sharing mechanism among all stakeholders is essential.

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 example is weather disturbances that cause construction delays.

Climate risks

Projects that are viewed as having an impact on climate change due to their direct or indirect carbon footprint may be increasingly challenged by policymakers, lenders and local residents. Equally, climate change and temperature rise may create additional uncertainty with regard to the resilience of facilities to scenarios of rise of the oceans.

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 altogether. 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 incomplete 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-utilisation of facilities or delays in start-up.

Samcheok LNG Terminal - Courtesy of Kogas

7. The LNG Industry in Years Ahead

What is the emerging trend in European LNG import market developments versus Russian pipeline gas supply?

The European gas market will continue to look at LNG imports as a way to diversify its natural gas supply. While Russia has been the largest exporter of natural gas to Europe and has influenced the European gas market, declines in European natural gas production in the Netherlands and elsewhere; growth of natural gas demand as a substitute for coal; and the competitive supply of Russian gas and global LNG; are shaping the European gas market.

The expansion of the Russian Nord Stream pipeline projects, including Nord Stream 2, and the TurkStream pipeline to southeastern Europe demonstrate Russia's approach as a long-term natural gas supplier to Europe. As a low-cost natural gas supplier, Russia is well positioned to maintain its position as a major gas supplier to Europe. However, with the expansion of US Atlantic basin export projects, LNG is becoming an increasingly viable supply source.

Under-utilised European receiving terminal capacity and development of additional capacity, especially through new projects, reduces physical constraints to LNG supply as a hedge. Due to the size of the projects and the short shipping distance, Russian LNG projects including Yamal, Arctic LNG, and Baltic LNG are expected to continue to play a role, exerting competitive pressures in the European LNG market, while the LNG developments in Qatar may also push the country to protect its European market share and to secure outlets in the region.

Eventually, Europe's ability to absorb additional LNG volumes will also depend on the ability of buyers to exert downward flexibility in long-term pipeline gas contracts, on the availability of underground gas storages and on the rate of coal-to-gas switching in the power sector.

Which project development barriers will newly importing markets and prospective importing markets face?

Many of the project development barriers captured in the 2012 IGU "Report of Study Group D.2: Penetration of New Markets for LNG" remain relevant to the current situation facing newly importing and potentially importing markets. Traditional barriers including project siting limitations, environmental and domestic land use requirements and opportunity costs, investment qualification and availability deficiencies, and policy uncertainties and instabilities will continue to exert pressure against LNG development among prospective importers. Institutional risk factors, even among technically- and economically-feasible projects, may play a major role as barriers to projects, especially up to the FID decision. Ultimately, such factors manifest themselves in the form of financial constraints and contingencies that make projects less feasible.

A newly-developed set of factors may include carbon emission policies, and potential taxation and banking policies. These factors have only recently been associated with determining project outcomes, but commitments to meet these societal goals may show up in tangible resistance to projects as environmental, social, and governance (ESG) metrics play a further increased role in project sanctions and investment criteria.

Different types of markets will require different approaches to ensure that an import value chain is implemented. For example, a larger but regulated market will need to ensure national and regional parties work together to link grid infrastructure to new import terminals. For developing markets, often the funding and financing of import projects is a struggle with several parties along the value chain wanting guarantees of others' financial commitments. As the LNG market is commoditising further, the role of different types of players in executing these projects have changed – trading houses now take stakes in import terminals where they did not previously do so, while larger portfolio players have been able to supply into flexible markets without necessarily being involved directly in the terminal through shareholding or capacity bookings. As the underlying barriers to developing import projects are unlikely to be removed in the immediate future, and participants roles are changing, it is important to consider how the industry can ensure import projects continue to be developed.

What are the remaining potential power generation opportunities for switching from coal to natural gas internationally? What are the opportunities for LNG imports and what role will regional differences play?

Natural gas from imported LNG will continue to play a major role in replacing coal and liquid fuel-fired electricity generation and reducing emissions, in both developed and developing economies.

However, capital constraints, availability of local gas production, gas infrastructure and national energy policies will impact coal-to-gas substitution rates. Regional differences in triggers for coal to gas switching (including gas versus coal price differentials, policies on carbon emissions, and prospects for carbon pricing) are important as well as policy roadmaps which influence infrastructure investment.

In its 2019 World Energy Outlook[1], the International Energy Agency estimated that a carbon price of $60-80/tonne CO_2 would be needed to provide enough support for the power sector to switch from coal to gas in China, whereas emissions savings from switching could be unlocked in Europe as soon as carbon prices exceed $20/tonne CO_2. As a result, simple measurements such as current coal-fired power capacity, are not reliable indicators of the opportunities for importing LNG as a replacement for other fuels.

Natural gas and LNG also have the potential to help balance variable renewable electricity generation and meet peak power demand. The economics of LNG supplied natural gas fired generation will become more challenging as their demand profile adjusts to balance variable renewable electricity generation and meet peak power demand.

Current forecasts by the International Energy Agency (from the World Energy Outlook[1]), indicate renewables could account for two-thirds of world electricity generation output and 37% of final energy consumption by 2040 under its "Sustainable Development Scenario." Under this forecast, LNG trade supporting displacement of coal-fired generation must find ways of working with renewable electricity infrastructure development to find the best uses of natural gas-fired generation in a "renewable electricity world."

How will LNG demand in China respond to the alternatives of LNG imports, Russia and Central Asia pipeline supply, and domestic production?

LNG demand in China is driven by a combination of price levels of LNG versus pipeline supply options from Central Asia and Russia, regional demand dynamics versus where supply comes in geographically. Security of supply may also be prioritised.

While China has consistently added import options, LNG import terminals and pipeline gas supply routes, infrastructure has not been connected comprehensively. This means that access points for LNG and gas do not necessarily always connect with demand centers and seasonal dynamics. The extent to which LNG demand in China will grow to a large extent depends on the ability to extend this infrastructure to ensure supply can efficiently reach demand centers.

Also in the near-term, however, recovery of the Chinese economy is needed to boost aggregate energy demand and to avoid dominance of Russian pipeline gas as the lowest-cost supply. In a fully recovered Chinese economy, both Russian gas and LNG imports can play significant roles based upon regional demand patterns, domestic infrastructure limitations, and the need to hedge against supplier dominance. Nevertheless, seasonality and regionality will continue to play major roles in China's exercising of options, including development of domestic supply and delivery within the domestic market.

In the long run the traditional drivers of relative prices, end user cost elasticity, and continuing regional differences in demand and availability are expected to play a role in how China exercises its options. It appears that an "all of the above" strategy might be best suited for China's geographic and economic scale. Additionally, this approach would be the prudent course to help ensure supply stability and security, which is needed to continue to grow the economy. While renewable energy is growing rapidly within China, the sheer scale of the needs for energy and distributed economic needs will require China to continue to diversify its energy sources.

[1] https://www.iea.org/reports/world-energy-outlook-2019

With the continuing wave of project FIDs, will we see trends in traditional versus newer commercial models for LNG export projects?

Final investment decisions in 2018 and 2019 have emphasised traditional project designs and orientations with most FIDs taken on integrated projects that have relied on equity financing. In large part, this tendency to focus on traditional commercial models is associated with stable oil and relative fuel prices, as well as the significant demand uncertainty faced by legacy as well as growth markets.

The continued evolution of the LNG market, with for instance more liquidity, may incentivise use of broader portfolio approaches, incorporating the flexibility of short term and spot markets to allow for arbitrage and hedging as energy prices change.

While traditional market approaches of long-term supply contracts are expected to continue to be in the mix to ensure supply security, more innovative spot and short-term project orientations are expected to cover more uncertain demand tranches. As some of the newer commercial models rely on external financing, the developers behind them had to convince that their market access is secured, by having 80 to 90% of offtake sold under long term SPAs. Very few projects were able to do this, on the contrary, most FIDs in 2018 and 2019 were taken by larger players that were able to rely on equity financing, and take FID without the need for long-term SPAs in place for their export volumes.

Concerns around reduced importance of economies of scale do not appear to be developing, except where barriers to development constrain the feasibility of large-scale projects. In the late 2010's, a significant debate over project scales and economies of scale emerged but recent projects with new configurations, like modular adjustments, appear to have settled the concern. For example, liquefaction added in smaller increments to reduce CAPEX risk. Economies of scale from what might become the fully-developed projects appears to be less of a concern now than controlling for project risk. For some players, and especially new market entrants, this is likely to serve as a model, especially for liquefaction projects. However, for other players, project scales that take full advantage of economies of scale will continue to be the driving consideration for project design, although staged expansion through rollout of multiple trains in the case of liquefaction is expected to continue.

Ultimately additional liquidity and availability of LNG benefits market functionality, and if by the time a next wave of sanctioning is required, some of the barriers faced by newer commercial models will have been addressed, and the industry could see the emergence of more advanced project configurations.

How is the increased flexibility demanded in LNG contracts influencing LNG shipping?

In keeping up with liquefaction capacity growth, LNG carrier capacity shortfalls will incentivise dedication to traditional trade and employment of carriers, increased market flexibility in the form of relief from destination clauses and shorter term contracts. Further LNG commoditisation will align shipping capacity more with these trends and drive commitments of carriers to more flexible trade.

In the longer term, LNG carrier newbuilds may show greater diversity in capacity to accommodate increasing flexibility demanded from contracts and capabilities to meet LNG transfer requirements of a more diverse import terminal population. The current level of newbuilds should be sufficient to allow for meeting broader technical requirements. Additionally, greater use of break bulk operations and other flexible shipping strategies can be implemented to provide greater flexibility. This includes reassignment of FSRUs to serve as LNG carriers, a development that we already see happening today. However, amid the slight current upward trends in shipping and LNG carrier construction, uncertainties regarding economic growth will continue to exert influence over expansion of shipping capacity and its employment. Additionally, efficiency improvements in LNG carrier operations and fuel usage will be increasingly important to maintain competitiveness as trade routes change with more flexible LNG trade.

The main challenges for LNG carrier owners are currently economic and technical. Utilisation of the steam carrier fleet, a less efficient option in terms of fuel consumption, increasing pressure on charter contracts with reduced periods and more competition with the entry of newcomers are the key commercial challenges. Selection of the right technologies for the new generation of ships is also key for the owner to succeed in the current environment.

How is regional bunkering infrastructure developing and are there any discrepancies the industry should consider?

Growth opportunities will continue to be most relevant in regional shipping, with larger international shipping opportunities expected in the future. Growth continues to be strong in the European, Northern Atlantic, Baltic, Mediterranean, and Asia-Pacific regions. To date, development of bunkering in the Middle East has lagged behind other regions.

Regarding drivers for bunkering development, increased attention to air pollution rules may provide a boost to LNG bunkering activity in affected regions, providing incentive beyond current IMO emissions rules focused on sulfur and NO_x. Technology developments oriented toward reducing total carbon emissions from vessels will need to be implemented to address both announced IMO GHG reduction objectives and carbon reduction emission policies. Continued development of marine engine technologies to improve performance and minimise "methane slip" in the emissions stream will enable onboard systems to better meet vessel requirements. Development of more uniform onshore fueling infrastructure and safety standards for integrating LNG bunkering activities within busy port operations is proceeding and is not expected to impose significant barriers to bunkering development.

How might global disruptions influence LNG trade in the near term?

Global disruptions, while often not predictable, may play important roles in short-term, and eventually long-term, trade activities. Trade impact may come from a variety of disruptions, including major weather events, trade disputes, pandemics, security threats and regional conflicts, and other transient influences. Increasing LNG market liquidity and trade flexibility may do much to reduce the short-term risks of such disturbances. Some of these influences are currently at work, and their impact on short-term trade are being assessed, in particular COVID-19. Other risks are less visible and may result in regionalised impacts.

In the longer term, most disruptions such as the effects of climate change and other sustained impacts may be accommodated by adjustments to physical LNG infrastructure and longer-term trade agreements. The long-term perspective, as a result, may require more portfolio-oriented planning while including short-term tools to address disruptions.

The other consideration for the impact of disruptive events are different lengths of cycles in the LNG industry. While capacity only gets added a number of years after sanctioning, the prevalent concerns at the time of sanctioning do affect decision making on projects. A key disruptive event during a sanctioning wave could dampen investment appetite and drive an earlier than expected supply and demand gap as less export capacity gets added than was required. On the other hand, a disruptive event during a period of build-out and oversupply could trigger concerns over security of supply, driving more long term contracting and ultimately potentially leading to continued over-supply.

LNG is clearly commoditising further — will it become a fully commoditised product or will there always be barriers that will prevent that from happening?

To achieve full commoditisation, LNG faces a "high bar" with respect to current trade patterns, energy needs, and physical constraints of transportation, storage, and handling of LNG. Different schools of thought speak to some of the barriers to full commoditisation.

While some market players see full commoditisation as both an objective and eventual reality, others still see that a significant portion of the industry will retain strategies using long-term agreements as a means of addressing security of supply, price stability, and project financing. LNG-term SPAs and fixed contract terms for large segments of the trade while appearing to hamper full commoditisation, are still needed to secure project financing Under this view, commoditisation would likely stay within the segment of trade represented by short-term and spot LNG, with limited effect overall.

Another signpost, and at the same time, enabler of further commoditisation of LNG would be the an LNG hub. Development of hubs can provide increased price transparency, flexibility, fungibility and liberalisation signposts essential to commoditisation. Hubs would also further underpin the ability to trade paper in addition to physical volumes. However, in the case of LNG, factors such as high project CAPEX for liquefaction, slow adjustment of supply and high transportation and storage costs, are not fully addressed by creation of physical and virtual LNG hubs.

Domestic energy policies are also expected to play an important role.

While signposts indicate that LNG has commoditised further since the last wave of sanctioning of supply, inherent barriers as discussed above, have not necessarily been mitigated, indicating that full commoditisation is unlikely to occur in the short term.

QGC LNG Plant - Courtesy of Shell

Will small-scale and mid-scale LNG facilities downstream of receiving terminals and other LNG sources continue to develop?

It is expected that use of LNG as a transport fuel for road and marine and potentially rail to expand, but perhaps at a slower pace than some innovators and first adopters have believed. Each of these LNG end use applications face specific opportunities and challenges.

LNG transportation to satellite LNG regasification operations for industrial facilities and remote communities is expected to increase due to economic development in areas that cannot be served by natural gas pipeline supplies in a timely way or face significant barriers. Initiatives to create "virtual LNG pipelines" to access isolated areas and create a more flexible supply, can increase and generate more demand for LNG. They also can reduce emissions, using LNG as a substitute to other, less clean, fossil fuels.

These applications imply a general growth in development of small-scale and mid-scale LNG storage facilities close to end use applications and markets. To date, worldwide activity in these distributed LNG markets has not been well characterised and represented in data, as is also the case in this report since the volumes of LNG do not meet the current reporting thresholds.

As described by various LNG prognosticators, the growth of the worldwide LNG industry is more challenged on the demand side than on the supply side. Small-scale and mid-scale LNG facilities downstream of the traditional LNG trade may provide a means to address impediments in demand growth as new vehicle and satellite facility opportunities are recognised. Greater efforts to capture data on these supply chains will provide greater clarity on how this infrastructure is developing.

Will floating gas-to-power capacity development show significant increases as a near-term alternative for LNG importation, and what are the drivers to choose this approach?

Activities supporting deployment of floating LNG power plants are expected to increase most readily among energy markets with high aggregate electric power demand growth and a strong need for rapid power capacity for expansion or introduction of electrical supply capacity in energy-poor regions. This is especially the case where high barriers for onshore power station development are in place or where access to gas pipelines is not guaranteed. These drivers may independently justify new projects and serve broadly diverse domestic economies and circumstances. Regardless of these drivers, floating gas-to-power projects will represent moderate to high technology risk and, on an individual project basis, relatively high CAPEX requirements for fully-independent power generation systems.

Floating power plant concepts fueled by LNG will have to compete with other floating power options including liquid fuels, renewables and nuclear power, which may receive governmental support over LNG. The most viable and low technology risk to these floating gas-to-power projects are FSRUs, for shore delivery of pipeline gas to a conventional onshore power station. As such, the strategy for deployment of floating gas-to-power appears to require a careful analysis of the market niche served by these projects over other, more conventional approaches. While implementation of floating gas-to-power projects are expected to roll out in the near future, Asian commercial interests will continue to lead technology and commercial development in floating LNG power concepts.

The concept of a fully integrated floating regasification and power plant may be a more realistic solution to grant easy access to clean electricity production. Therefore, such fast track projects, built and commissioned at reputed shipyards, may materialise in the near future.

What improvements in emissions measurement and controls will help the LNG industry reduce its environmental footprint?

Critical emissions streams for consideration from the LNG value chain include carbon emissions in the form of carbon dioxide and methane emissions. The major contributor to LNG's carbon footprint is associated with combustion from power generation and heat generation and in the form of carbon dioxide from liquefaction operations (principally from power generation), ship prime movers, and several key regasification approaches. For reductions in carbon dioxide, greater process efficiency will continue to be the most important and impactful mitigation measure. Some of the near-term means of pursuing these improvements are outlined in the 2015 IGU report, "Programme Committee D Study Group 4: Life Cycle Assessment of LNG."

Methane emissions represent product losses as fugitive emissions and will continue to be addressed losses of LNG operations. As such, reduction of methane emissions will be in the interest of LNG operators to control product losses, regardless of potential regulatory interventions. To a lesser extent, methane emissions from flaring and other operations contribute to the LNG value chain carbon footprint and will continue to be emphasised for control. However, regulation of methane emissions will receive increased emphasis in domestic regulatory schemes and through international requirements, especially in the latter case for marine operations where fugitive emissions and "methane slip" from engine combustion contribute. Monitoring efforts for methane losses and maintenance of emission inventories will continue to be emphasised, whether required by regulatory authorities and where not required. Remote sensing technologies will be increasingly deployed across LNG operations to assist ultimately in methane emissions control.

What innovative LNG receiving terminal business operations will the industry see in the coming years?

As dynamics of LNG importing markets continue to evolve with changing economic conditions, growth in renewable energy sources, natural gas infrastructure build-out, and policy and regulatory shifts, major players and receiving markets are expected to emergence of new business models.

For example in Spain, regulatory changes in the domestic LNG market are moving toward implementing what is called a "virtual global LNG tank" model in the next decade. This unifies the entire domestic capacity of LNG terminals including storage, regasification, and natural gas send out as a single business entity instead of separate physical assets. Spain's total LNG storage capacity of natural gas will be commercialised as a single "tank," independently of the physical facilities located around the market. In doing so, business decisions based upon individual facility capacity utilisation and operations will play a much reduced role in commercial activities, and the importance of individual facility data and characterisations, as reported in this document historically, will likewise play a reduced role for the purposes of the Spanish natural gas industry. Under this new regulatory model, to be initiated on 1 April 2020 and fully implemented by 1 October 2020, the Spanish system's total LNG storage capacity of 3.17 mmcm and total regasification capacity of 43.8 MTPA will be commercialised as a "global capacity". The new model is expected to give more flexibility and liquidity in the LNG market by adding together Spain's LNG receiving terminal capacities, and to create a liquid virtual hub.

While it is unclear what other innovations we may see, continued consideration of virtual hub development, breakbulk carrier operations, "milk run" transportation models, containerised delivery by multi modal transportation, use of FSRUs and other floating assets may play a greater role in LNG receiving country business models as they adapt to changing market conditions and the need to accommodate short-term and spot LNG trade activity and efforts to implement greater flexibility and market liquidity.

Methane Mickie Harpet at QGC LNG Plant - Courtesy of Shell

8.
References Used in the 2020 Edition

8.1 DATA COLLECTION FOR CHAPTER 3,4,5 AND 6

Data in Chapters 3, 4, 5 and 6 of the 2020 IGU World LNG Report is sourced from a range of public and private domains, including the BP Statistical Review of World Energy, 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, Rystad Energy, Refinitiv Eikon, Barry Rogliano Salles (BRS), company reports and announcements. Additionally, any private data obtained from third-party organisations are cited as a source at the point of reference (i.e. charts and tables). 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.

8.2 DATA COLLECTION FOR CHAPTER 2

Data in Chapter 2 of the 2020 IGU World LNG Report is sourced from the International Group of Liquefied Natural Gas Importers (GIIGNL). 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.

8.3 PREPARATION AND PUBLICATION OF THE 2020 IGU WORLD LNG 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
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•Osaka Gas, Japan: Tamotsu Manabe
•Rystad Energy, Norway: Martin Opdal, Jon Fredrik Müller
•Shell, The Netherlands: Birthe van Vliet

8.4 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.

Commercial Operations: For LNG liquefaction plants, commercial operations start when the plants deliver commercial cargos under the supply contracts with their customers.

East and West of Suez: The terms East and West of Suez refer to the location where an LNG tanker fixture begins. For these purposes, marine locations to the west of the Suez Canal, Cape of Good Hope, or Novaya Zemlya, but to the east of Tierra del Fuego, the Panama Canal, or Lancaster Sound, are considered to lie west of Suez. Other points are considered to lie east of Suez.

Forecasted Data: Forecasted liquefaction and regasification capacity data only considers existing and sanctioned 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.

Laid-Up Vessel: A vessel is considered laid-up when it is inactive and temporarily out of commercial operation. This can be due to low freight demand or when running costs exceed ongoing freight rates. Laid-up LNG vessels can return to commercial operation, undergo FSU/FSRU conversion or proceed to be sold for scrap.

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 "Shipping" chapter (Chapter 5). Vessels with a capacity of 30,000 cm or less are considered small-scale LNG carriers.

Scale of LNG Trains:

-Small-scale: 0-0.5 MTPA capacity per train

-Mid-scale: >0.5-1.5 MTPA capacity per train

-Large-scale: More than 1.5 MTPA capacity per train

Spot Charter Rates: Spot charter rates refer to fixtures beginning between five days after the date of assessment and the end of the following calendar month.

8.5 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 considered markets with liquefaction or regasification activities in multiple basins and has adjusted the data accordingly.

Figure 8.1: Grouping of Markets into Regions

8.6 ACRONYMS

CAPEX = Capital Expenditures
CSG = Coal Seam Gas
DFDE = Dual-Fuel Diesel Electric
DMR = Dual Mixed Refrigerant
EPC = Engineering, Procurement and Construction
EU = European Union
FEED = Front-End Engineering and Design
FERC = Federal Energy Regulatory Commission
FID = Final Investment Decision
FLNG = Floating Liquefaction
FPSO = Floating Production, Storage, and Offloading
FSRU = Floating Storage and Regasification Unit
FSU = Floating Storage Unit
FSU = Former Soviet Union
GCU = Gas Combustion Unit
GTT = Gaztransport and Technigaz
IHI = Ishikawajima Heavy Industries
ISO = International Organisation for Standardisation
LPG = Liquefied Petroleum Gas
MEGI = M-type, Electronically Controlled, Gas Injection
MMLS = Moveable Modular Liquefaction System
OPEX = Operating Expenditures
SPA = Sales and Purchase Agreement
STaGE = Steam Turbine and Gas Engine
SSDR = Slow Speed Diesel with Re-liquefaction plant
TFDE = Triple-Fuel Diesel Electric
UAE = United Arab Emirates
UK = United Kingdom
US = United States
YOY = Year-on-Year

8.7 UNITS

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

8.8 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	0.45		5.85×10^{-4}	0.0207	24.02	4.141
mmcm gas	769.2	1,700		35.31	41,100	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	0.1724
boe	0.1087	0.2415	1.41×10^{-4}	0.00499	5.8	

8.9 Discrepancies in Data vs. Previous IGU World LNG Reports

Due to the use of different datasources in the 2020 IGU World LNG Report compared to earlier IGU World LNG Reports, there may be some data discrepancies between stated totals for 2018 and before 2018 in this report, compared to those same totals stated in earlier reports IGU World LNG Reports.

In addition, the Trade section of this report is based on data from GIIGNL, whereas the remaining sections have used a wide range of sources.

Appendix 1: Table of Global Liquefaction Plants

Reference Number	Market	Liquefaction Plant Train	Infrastructure Start Year	Liquefaction Capacity (MTPA)	Owners	Liquefaction Technology
1	Libya	Marsa El Brega LNG T1-4[1]	1970	3.20	LNOC	AP-SMR
2	Brunei	Brunei LNG T1-T2	1972	2.88	Shell*; Brunei Government ; Mitsubishi Corp	AP-C3MR
2	Brunei	Brunei LNG T3-T4	1973	2.88	Shell*; Brunei Government ; Mitsubishi Corp	AP-C3MR
2	Brunei	Brunei LNG T5	1974	1.44	Shell*; Brunei Government ; Mitsubishi Corp	AP-C3MR
3	UAE	ADGAS LNG T1-2	1977	2.60	ADNOC LNG* (0%); Abu Dhabi NOC ; Mitsui; BP; Total;	AP-C3MR
4	Algeria	Arzew GL1Z T1-T6	1978	7.90	Sonatrach*	AP-C3MR
4	Algeria	Arzew GL2Z T1-T6	1981	8.40	Sonatrach*	AP-C3MR
5	Indonesia	Bontang LNG TC-TD3	1983	5.60	Pertamina* ; PT VICO Indonesia; Total	AP-C3MR
6	Malaysia	MLNG Satu T1-T3	1983	8.40	Petronas*; Mitsubishi Corp; Sarawak State	AP-C3MR
5	Indonesia	Bontang LNG TE	1989	2.80	Pertamina* ; PT VICO Indonesia; Total	AP-C3MR
7	Australia	North West Shelf LNG T1-2	1989	5.00	Woodside*; BHP; BP ; Chevron; Shell; Mitsubishi Corp; Mitsui	AP-C3MR
7	Australia	North West Shelf LNG T3	1992	2.50	Woodside*; BHP; BP ; Chevron; Shell; Mitsubishi Corp; Mitsui	AP-C3MR
5	Indonesia	Bontang LNG TF	1993	2.80	Pertamina* ; PT VICO Indonesia; Total	AP-C3MR
3	UAE	ADGAS LNG T3	1994	3.20	ADNOC LNG* (0%); Abu Dhabi NOC ; Mitsui; BP; Total	AP-C3MR
6	Malaysia	MLNG Dua T4-T5	1995	6.40	Petronas*; Mitsubishi Corp; Sarawak State	AP-C3MR
6	Malaysia	MLNG Dua T6	1995	3.20	Petronas*; Mitsubishi Corp; Sarawak State	AP-C3MR
8	Qatar	Qatargas 1 T1	1996	3.20	Qatargas* (0%); Qatar Petroleum; ExxonMobil; Total ; Marubeni; Mitsui	AP-C3MR
5	Indonesia	Bontang LNG TG	1997	2.80	Pertamina* ; PT VICO Indonesia; Total	AP-C3MR
8	Qatar	Qatargas 1 T2	1997	3.20	Qatargas* (0%); Qatar Petroleum; ExxonMobil; Total ; Marubeni; Mitsui	AP-C3MR
8	Qatar	Qatargas 1 T3	1998	3.20	Qatargas* (0%); Qatar Petroleum; ExxonMobil; Total ; Marubeni; Mitsui	AP-C3MR
5	Indonesia	Bontang LNG TH	1999	2.95	Pertamina* ; PT VICO Indonesia; Total	AP-C3MR
8	Qatar	Rasgas 1 T1	1999	3.30	Qatargas* (0%); Qatar Petroleum; ExxonMobil; ITOCHU; Korea Gas; Sojitz; Sumitomo; Samsung; Hyundai; SK Energy; LG International; Daesung; Hanwha Energy	AP-C3MR
9	Trinidad and Tobago	Atlantic LNG T1	1999	3.00	Atlantic LNG* (0%); Shell; BP; China Investment Corporation; NGC	ConocoPhillips Optimized Cascade
10	Nigeria	NLNG T1-2	1999	6.60	NNPC (Nigeria)*; Shell; Total; Eni	AP-C3MR
8	Qatar	Rasgas 1 T2	2000	3.30	Qatargas* (0%); Qatar Petroleum; ExxonMobil; ITOCHU; Korea Gas; Sojitz; Sumitomo; Samsung; Hyundai; SK Energy; LG International; Daesung; Hanwha Energy	AP-C3MR

[1]Marsa El Brega LNG in Libya has not been operational since 2011. It is included for reference only.

Appendix 1: Table of Global Liquefaction Plants (continued)

Reference Number	Market	Liquefaction Plant Train	Infrastructure Start Year	Liquefaction Capacity (MTPA)	Owners	Liquefaction Technology
11	Oman	Oman LNG T1-2	2000	7.10	Oman LNG* (0%); Omani Government; Shell; Total; Korea LNG; Mitsubishi Corp; Mitsui; Partex (Gulbenkian Foundation); ITOCHU	AP-C3MR
9	Trinidad and Tobago	Atlantic LNG T2	2002	3.30	Atlantic LNG* (0%); Shell; BP	ConocoPhillips Optimized Cascade
10	Nigeria	NLNG T3	2002	3.30	NNPC (Nigeria)*; Shell; Total; Eni	AP-C3MR
6	Malaysia	MLNG Tiga T7-T8	2003	7.70	Petronas*; Sarawak State; JX Nippon Oil and Gas; Mitsubishi Corp	AP-C3MR
9	Trinidad and Tobago	Atlantic LNG T3	2003	3.30	Atlantic LNG*; Shell; BP	ConocoPhillips Optimized Cascade
7	Australia	North West Shelf LNG T4	2004	4.60	Woodside*; BHP; BP ; Chevron; Shell; Mitsubishi Corp; Mitsui	AP-C3MR
8	Qatar	Rasgas 2 T3	2004	4.70	Qatargas* (0%); Qatar Petroleum ; ExxonMobil	AP-C3MR/ SplitMR
8	Qatar	Rasgas 2 T4	2005	4.70	Qatargas* (0%); Qatar Petroleum ; ExxonMobil	AP-C3MR/ SplitMR
9	Trinidad and Tobago	Atlantic LNG T4	2005	5.20	Atlantic LNG* (0%); Shell; BP; NGC	ConocoPhillips Optimized Cascade
10	Nigeria	NLNG T4	2005	4.10	NNPC (Nigeria)*; Shell; Total; Eni	AP-C3MR
12	Egypt	Damietta LNG T1[2]	2005	5.00	Union Fenosa*; Eni; EGPC (Egypt)	AP-C3MR/ SplitMR
13	Egypt	Egyptian LNG (Idku) T1-2	2005	7.20	Shell*; Petronas; EGPC (Egypt); EGAS; Total	ConocoPhillips Optimized Cascade
10	Nigeria	NLNG T5	2006	4.10	NNPC (Nigeria)*; Shell; Total; Eni	AP-C3MR
11	Oman	Oman LNG T3 (Qalhat)	2006	3.30	Oman LNG* (0%); Omani Government; Shell; Mitsubishi Corp; Eni; Gas Natural SDG; ITOCHU; Osaka Gas; Total; Korea LNG; Mitsui; Partex (Gulbenkian Foundation)	AP-C3MR
14	Australia	Darwin LNG T1	2006	3.70	Santos*; Inpex; Eni; Tokyo Electric; Tokyo Gas	ConocoPhillips Optimized Cascade
8	Qatar	Rasgas 2 T5	2007	4.70	Qatargas* (0%); Qatar Petroleum ; ExxonMobil	AP-C3MR/ SplitMR
10	Nigeria	NLNG T6	2007	4.10	NNPC (Nigeria)*; Shell; Total; Eni	AP-C3MR
15	Equatorial Guinea	EG LNG T1	2007	3.70	Marathon Oil*; Sonagas G.E.; Mitsui; Marubeni	ConocoPhillips Optimized Cascade
16	Norway	Snohvit LNG T1	2007	4.20	Equinor*; Petoro; Total; Neptune Energy; Wintershall Dea	Linde MFC
7	Australia	North West Shelf LNG T5	2008	4.60	Woodside*; BHP; BP ; Chevron; Shell; Mitsubishi Corp; Mitsui	AP-C3MR
8	Qatar	Qatargas 2 T4-5	2009	15.60	Qatargas* (0%); Qatar Petroleum; ExxonMobil; Total	AP-X
8	Qatar	Rasgas 3 T6-7	2009	15.60	Qatargas* (0%); Qatar Petroleum ; ExxonMobil	AP-X

[2]Damietta LNG (SEAGAS LNG) has not exported since the end of 2012. The plant remained idle in 2019 but may restart operations in 2020.

Appendix 1: Table of Global Liquefaction Plants (continued)

Reference Number	Market	Liquefaction Plant Train	Infrastructure Start Year	Liquefaction Capacity (MTPA)	Owners	Liquefaction Technology
17	Russia	Sakhalin 2 T1-2	2009	9.60	Sakhalin Energy Investment Company* (0%); Gazprom ; Shell; Mitsui; Mitsubishi Corp	Shell DMR
18	Indonesia	Tangguh LNG T1	2009	3.80	BP*; CNOOC; JOGMEC; Mitsubishi Corp; Inpex; JX Nippon Oil and Gas; Sojitz; Sumitomo; Mitsui	AP-C3MR/ SplitMR
19	Yemen	Yemen LNG T1-2[3]	2009	6.70	Total*; Yemen Gas Company; Hunt Oil; Korea Gas; SK Energy; Hyundai; Social Security and Pensions (GASSP)	AP-C3MR/ SplitMR
8	Qatar	Qatargas 3 T6	2010	7.80	Qatargas* (0%); Qatar Petroleum; ConocoPhillips; Mitsui	AP-X
18	Indonesia	Tangguh LNG T2	2010	3.80	BP*; CNOOC; JOGMEC; Mitsubishi Corp; Inpex; JX Nippon Oil and Gas; Sojitz; Sumitomo; Mitsui	AP-C3MR/ SplitMR
20	Peru	Peru LNG T1	2010	4.45	Hunt Oil* ; Repsol; SK Energy; Marubeni	AP-C3MR/ SplitMR
8	Qatar	Qatargas 4 T7	2011	7.80	Qatargas* (0%); Qatar Petroleum ; Shell	AP-X
21	Australia	Pluto LNG T1	2012	4.90	Woodside*; Kansai Electric; Tokyo Gas	Shell Propane Precooled Mixed Refrigerant
4	Algeria	Skikda GL1K T1 (rebuild)	2013	4.50	Sonatrach*	AP-C3MR/ SplitMR
22	Angola	Angola LNG T1	2013	5.20	Angola LNG* (0%); Chevron; Sonangol; BP; Eni; Total	ConocoPhillips Optimized Cascade
4	Algeria	Arzew GL3Z (Gassi Touil) T1	2014	4.70	Sonatrach*	AP-C3MR/ SplitMR
23	Papua New Guinea	PNG LNG T1-2	2014	6.90	ExxonMobil*; Oil Search; PNG Government; Santos; JX Nippon Oil and Gas; Mineral Resources Development; Marubeni	AP-C3MR
24	Indonesia	Donggi-Senoro LNG T1	2015	2.00	Donggi-Senoro LNG (DSLNG)* (0%); Mitsubishi Corp; Pertamina; Korea Gas; MedcoEnergi	AP-C3MR
25	Australia	GLNG T1	2015	3.90	Santos*; Petronas; Total; Korea Gas	ConocoPhillips Optimized Cascade
26	Australia	Queensland Curtis LNG T1-2	2015	8.50	Shell* ; CNOOC	ConocoPhillips Optimized Cascade
25	Australia	GLNG T2	2016	3.90	Santos*; Petronas; Total; Korea Gas	ConocoPhillips Optimized Cascade
27	Australia	Australia Pacific LNG T1-2	2016	9.00	Origin Energy*; ConocoPhillips; Sinopec Group	ConocoPhillips Optimized Cascade
28	Australia	Gorgon LNG T1-2	2016	10.40	Chevron*; ExxonMobil; Shell ; Osaka Gas; Tokyo Gas; Chubu Electric	AP-C3MR/ SplitMR
29	United States	Sabine Pass T1-T2	2016	9.00	Cheniere Energy*	ConocoPhillips Optimized Cascade

[3]Yemen LNG has not exported since 2015 due to ongoing civil war.

Appendix 1: Table of Global Liquefaction Plants (continued)

Reference Number	Market	Liquefaction Plant Train	Infrastructure Start Year	Liquefaction Capacity (MTPA)	Owners	Liquefaction Technology
6	Malaysia	MLNG T9	2017	3.60	Petronas*; JX Nippon Oil and Gas; Sarawak State	AP-C3MR/ SplitMR
28	Australia	Gorgon LNG T3	2017	5.20	Chevron*; ExxonMobil; Shell; Osaka Gas; Tokyo Gas; Chubu Electric	AP-C3MR/ SplitMR
29	United States	Sabine Pass T3-T4	2017	9.00	Cheniere Energy*	ConocoPhillips Optimized Cascade
30	Malaysia	Petronas FLNG Satu	2017	1.20	Petronas*	AP-N
31	Australia	Wheatstone LNG T1	2017	4.45	Chevron*; Kuwait Petroleum Corp (KPC); Woodside; JOGMEC; Mitsubishi Corp; Kyushu Electric; Nippon Yusen; Chubu Electric; Tokyo Electric	ConocoPhillips Optimized Cascade
32	Russia	Yamal LNG T1	2017	5.50	Novatek*; CNPC; Total; Silk Road Fund	AP-C3MR
31	Australia	Wheatstone LNG T2	2018	4.45	Chevron*; Kuwait Petroleum Corp (KPC); Woodside; JOGMEC; Mitsubishi Corp; Kyushu Electric; Nippon Yusen; Chubu Electric; Tokyo Electric	ConocoPhillips Optimized Cascade
32	Russia	Yamal LNG T2	2018	5.50	Novatek*; CNPC; Total; Silk Road Fund	AP-C3MR
33	Cameroon	Cameroon FLNG	2018	2.40	Golar*	Black and Veatch PRICO
34	United States	Cove Point LNG T1	2018	5.25	Dominion Cove Point LNG LP*	AP-C3MR
29	United States	Sabine Pass T5	2019	4.50	Cheniere Energy*	ConocoPhillips Optimized Cascade
32	Russia	Yamal LNG T3	2019	5.50	Novatek*; CNPC; Total; Silk Road Fund	AP-C3MR
35	Australia	Ichthys LNG T1-2	2019	8.90	Inpex*; Total; CPC (Chinese Taipei); Tokyo Gas; Kansai Electric; Osaka Gas; Chubu Electric; Toho Gas	AP-C3MR/ SplitMR
36	Argentina	Tango FLNG	2019	0.50	Exmar*	Black and Veatch PRICO
37	United States	Corpus Christi T1	2019	4.50	Cheniere Energy*	ConocoPhillips Optimized Cascade
37	United States	Cameron LNG T1	2019	4.00	Cameron LNG* (0%); Sempra; Mitsui; Total; Mitsubishi Corp; Nippon Yusen Kabushiki Kaisha	AP-C3MR/ SplitMR
38	United States	Corpus Christi T2	2019	4.5	Cheniere Energy*	ConocoPhillips Optimized Cascade
39	United States	Freeport LNG T1	2019	5.10	Freeport LNG*; Zachry Hastings; Osaka Gas; Dow Chemical Company; Global Infrastructure Partners	AP-C3MR
40	Australia	Prelude FLNG	2019	3.60	Shell*	Shell DMR
41	Russia	Vysotsk LNG T1	2019	0.66	Novatek*, Gazprombank	Air Liquide Smartfin
42	United States	Elba Island T1-T3	2019	0.75	Southern LNG*; Kinder Morgan; EIG Partners	Shell MMLS

Appendix 2: Table of Liquefaction Plants Sanctioned or Under Construction

Market	Liquefaction Plant Train	Infrastructure Start Year	Liquefaction Capacity (MTPA)	Owners	Liquefaction Technology
United States	Elba Island T4-10	2020	1.75	Southern LNG*; Kinder Morgan; EIG Partners	Shell MMLS
Indonesia	Sengkang LNG T1	2020	0.5	Energy World*	Chart Industries IPSMR
United States	Cameron LNG T2-3	2020	8.0	Cameron LNG*; Sempra; Mitsui; Total; Mitsubishi Corp; Nippon Yusen Kabushiki Kaisha	AP-C3MR/SplitMR
United States	Freeport LNG T2-3	2020	10.2	Freeport LNG*; Zachry Hastings; Osaka Gas; Dow Chemical Company; Global Infrastructure Partners	AP-C3MR
Malaysia	Petronas FLNG Dua	2020	1.5	Petronas*	AP-N
Russia	Portovaya LNG T1	2020	1.5	Gazprom*	Linde LIMUM
Russia	Yamal LNG T4	2020	0.9	Novatek*; CNPC; Total; Silk Road Fund	Novatek Arctic Cascade
United States	Corpus Christi T3	2021	4.5	Cheniere Energy*	ConocoPhillips Optimized Cascade
Indonesia	Tangguh LNG T3	2021	3.8	BP*; CNOOC; JOGMEC; Mitsubishi Corp; Inpex; JX Nippon Oil and Gas; Sojitz; Sumitomo; Mitsui	AP-C3MR/SplitMR
Mozambique	Coral South FLNG	2022	3.4	Eni*; ExxonMobil; CNPC; ENH (Mozambique); Galp Energia SA; Korea Gas	AP-DMR
Mauritania	Tortue/Ahmeyim FLNG T1	2022	2.5	Golar	Black and Veatch PRICO
United States	Calcasieu Pass LNG T1-18	2023	10	Venture Global LNG*	BHGE SMR
United States	Sabine Pass T6	2023	4.5	Cheniere Energy*	ConocoPhillips Optimized Cascade
Russia	Arctic LNG 2 T1	2024	6.6	Novatek*; CNOOC; CNPC; Total; JOGMEC; Mitsui	Linde MFC
United States	Golden Pass LNG T1-3	2024	15.6	Golden Pass Products*; Qatar Petroleum; ExxonMobil	AP-C3MR/SplitMR
Canada	LNG Canada T1-2	2024	14.0	Shell*; Petronas ; Mitsubishi Corp; PetroChina; Korea Gas	Shell DMR
Mozambique	Mozambique LNG (Area 1) T1-2	2024	12.88	Total*; Mitsui; ONGC (India); ENH (Mozambique); Bharat Petroleum Corp (BPCL); PTTEP (Thailand); Oil India	AP-C3MR
Nigeria	NLNG T7	2024	8.0	NNPC (Nigeria)*; Shell; Total; Eni	AP-C3MR
Russia	Arctic LNG 2 T2-3	2025	13.2	Novatek*; CNOOC; CNPC; Total; JOGMEC; Mitsui	Linde MFC

Note:

1. In the ownership column, companies with "*" refer to plant operators. If a company doesn't have any ownership stake in the LNG plant, it will be marked with "(0%)".

Appendix 3: Table of Global Active LNG Fleet, Year-End 2019

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9443401	Aamira	Nakilat	Samsung	266000	Membrane	Q-Max	SSDR	2010
9210828	Abadi	Brunei Gas Carriers	Mitsubishi	137000	Spherical	Conventional	Steam	2002
9501186	Adam LNG	Oman Shipping Co (OSC)	Hyundai	162000	Membrane	Conventional	DFDE	2014
9831220	Adriano Knutsen	Knutsen OAS	Hyundai	180000	Membrane	Conventional	MEGI	2019
9338266	Al Aamriya	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	216200	Membrane	Q-Flex	SSDR	2008
9325697	Al Areesh	Teekay	Daewoo	151700	Membrane	Conventional	Steam	2007
9431147	Al Bahiya	Nakilat	Daewoo	210100	Membrane	Q-Flex	SSDR	2010
9132741	Al Bidda	J4 Consortium	Kawasaki	137300	Spherical	Conventional	Steam	1999
9325702	Al Daayen	Teekay	Daewoo	151700	Membrane	Conventional	Steam	2007
9443683	Al Dafna	Nakilat	Samsung	266400	Membrane	Q-Max	SSDR	2009
9307176	Al Deebel	MOL, NYK, K Line	Samsung	145700	Membrane	Conventional	Steam	2005
9337705	Al Gattara	Nakilat, OSC	Hyundai	216200	Membrane	Q-Flex	SSDR	2007
9337987	Al Ghariya	Commerz Real, Nakilat, PRONAV	Daewoo	210200	Membrane	Q-Flex	SSDR	2008
9337717	Al Gharrafa	Nakilat, OSC	Hyundai	216200	Membrane	Q-Flex	SSDR	2008
9397286	Al Ghashamiya	Nakilat	Samsung	217600	Membrane	Q-Flex	SSDR	2009
9372743	Al Ghuwairiya	Nakilat	Daewoo	263300	Membrane	Q-Max	SSDR	2008
9337743	Al Hamla	Nakilat, OSC	Samsung	216200	Membrane	Q-Flex	SSDR	2008
9074640	Al Hamra	National Gas Shipping Co	Kvaerner Masa	135000	Spherical	Conventional	Steam	1997
9360879	Al Huwaila	Nakilat, Teekay	Samsung	217000	Membrane	Q-Flex	SSDR	2008
9132791	Al Jasra	J4 Consortium	Mitsubishi	137200	Spherical	Conventional	Steam	2000
9324435	Al Jassasiya	Maran G.M, Nakilat	Daewoo	145700	Membrane	Conventional	Steam	2007
9431123	Al Karaana	Nakilat	Daewoo	210100	Membrane	Q-Flex	SSDR	2009
9397327	Al Kharaitiyat	Nakilat	Hyundai	216300	Membrane	Q-Flex	SSDR	2009
9360881	Al Kharsaah	Nakilat, Teekay	Samsung	217000	Membrane	Q-Flex	SSDR	2008
9431111	Al Khattiya	Nakilat	Daewoo	210200	Membrane	Q-Flex	SSDR	2009
9038440	Al Khaznah	National Gas Shipping Co	Mitsui	135000	Spherical	Conventional	Steam	1994
9085613	Al Khor	J4 Consortium	Mitsubishi	137400	Spherical	Conventional	Steam	1996
9360908	Al Khuwair	Nakilat, Teekay	Samsung	217000	Membrane	Q-Flex	SSDR	2008
9397315	Al Mafyar	Nakilat	Samsung	266400	Membrane	Q-Max	SSDR	2009
9325685	Al Marrouna	Nakilat, Teekay	Daewoo	152600	Membrane	Conventional	Steam	2006
9397298	Al Mayeda	Nakilat	Samsung	266000	Membrane	Q-Max	SSDR	2009
9431135	Al Nuaman	Nakilat	Daewoo	210100	Membrane	Q-Flex	SSDR	2009
9360790	Al Oraiq	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	210200	Membrane	Q-Flex	SSDR	2008
9086734	Al Rayyan	J4 Consortium	Kawasaki	137400	Spherical	Conventional	Steam	1997
9397339	Al Rekayyat	Nakilat	Hyundai	216300	Membrane	Q-Flex	SSDR	2009
9337951	Al Ruwais	Commerz Real, Nakilat, PRONAV	Daewoo	210200	Membrane	Q-Flex	SSDR	2007

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9397341	Al Sadd	Nakilat	Daewoo	210200	Membrane	Q-Flex	SSDR	2009
9337963	Al Safliya	Commerz Real, Nakilat, PRONAV	Daewoo	210200	Membrane	Q-Flex	SSDR	2007
9360855	Al Sahla	NYK, K Line, MOL, lino, Mitsui, Nakilat	Hyundai	216200	Membrane	Q-Flex	SSDR	2008
9388821	Al Samriya	Nakilat	Daewoo	263300	Membrane	Q-Max	SSDR	2009
9360893	Al Shamal	Nakilat, Teekay	Samsung	217000	Membrane	Q-Flex	SSDR	2008
9360831	Al Sheehaniya	Nakilat	Daewoo	210200	Membrane	Q-Flex	SSDR	2009
9298399	Al Thakhira	K Line, Qatar Shpg.	Samsung	145700	Membrane	Conventional	Steam	2005
9360843	Al Thumama	NYK, K Line, MOL, lino, Mitsui, Nakilat	Hyundai	216200	Membrane	Q-Flex	SSDR	2008
9360867	Al Utouriya	NYK, K Line, MOL, lino, Mitsui, Nakilat	Hyundai	215000	Membrane	Q-Flex	SSDR	2008
9085625	Al Wajbah	J4 Consortium	Mitsubishi	137300	Spherical	Conventional	Steam	1997
9086746	Al Wakrah	J4 Consortium	Kawasaki	137600	Spherical	Conventional	Steam	1998
9085649	Al Zubarah	J4 Consortium	Mitsui	137600	Spherical	Conventional	Steam	1996
9343106	Alto Acrux	TEPCO, NYK, Mitsubishi	Mitsubishi	147800	Spherical	Conventional	Steam	2008
9682552	Amadi	Brunei Gas Carriers	Hyundai	154800	Membrane	Conventional	TFDE	2015
9496317	Amali	Brunei Gas Carriers	Daewoo	147000	Membrane	Conventional	TFDE	2011
9661869	Amani	Brunei Gas Carriers	Hyundai	154800	Membrane	Conventional	TFDE	2014
9317999	Amur River	Dynagas	Hyundai	149700	Membrane	Conventional	Steam	2008
9645970	Arctic Aurora	Dynagas	Hyundai	155000	Membrane	Conventional	TFDE	2013
9276389	Arctic Discoverer	K Line, Statoil, Mitsui, lino	Mitsui	142600	Spherical	Conventional	Steam	2006
9284192	Arctic Lady	Hoegh	Mitsubishi	148000	Spherical	Conventional	Steam	2006
9271248	Arctic Princess	Hoegh, MOL, Statoil	Mitsubishi	148000	Spherical	Conventional	Steam	2006
9001784	Arctic Spirit	Teekay	I.H.I.	87300	Self-Supporting Prismatic	Conventional	Steam	1993
9275335	Arctic Voyager	K Line, Statoil, Mitsui, lino	Kawasaki	142800	Spherical	Conventional	Steam	2006
9496305	Arkat	Brunei Gas Carriers	Daewoo	147000	Membrane	Conventional	TFDE	2011
8125868	Armada LNG Mediterrana	Bumi Armada Berhad	Mitsui	127209	Spherical	FSU	Steam	1985
9339260	Arwa Spirit	Teekay, Marubeni	Samsung	168900	Membrane	Conventional	DFDE	2008
9377547	Aseem	MOL, NYK, K Line, SCI, Nakilat, Petronet	Samsung	155000	Membrane	Conventional	DFDE	2009
9610779	Asia Endeavour	Chevron	Samsung	160000	Membrane	Conventional	DFDE	2015
9606950	Asia Energy	Chevron	Samsung	160000	Membrane	Conventional	DFDE	2014
9610767	Asia Excellence	Chevron	Samsung	160000	Membrane	Conventional	DFDE	2015

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9680188	Asia Integrity	Chevron	Samsung	160000	Membrane	Conventional	DFDE	2017
9680190	Asia Venture	Chevron	Samsung	160000	Membrane	Conventional	TFDE	2017
9606948	Asia Vision	Chevron	Samsung	160000	Membrane	Conventional	TFDE	2014
9771080	Bahrain Spirit	Teekay	Daewoo	173000	Membrane	FSU	MEGI	2018
9401295	Barcelona Knutsen	Knutsen OAS	Daewoo	173400	Membrane	Conventional	TFDE	2009
9613159	Beidou Star	MOL, China LNG	Hudong-Zhonghua	171800	Membrane	Conventional	SSDR	2015
9256597	Berge Arzew	BW	Daewoo	138000	Membrane	Conventional	Steam	2004
9236432	Bilbao Knutsen	Knutsen OAS	IZAR	138000	Membrane	Conventional	Steam	2004
9691137	Bishu Maru	Trans Pacific Shipping	Kawasaki	164700	Spherical	Conventional	Steam Reheat	2017
9768394	Boris Davydov	Sovcomflot	Daewoo	172000	Membrane	Icebreaker	TFDE	2018
9768368	Boris Vilkitsky	Sovcomflot	Daewoo	172600	Membrane	Icebreaker	TFDE	2017
9766542	British Achiever	BP	Daewoo	174000	Membrane	Conventional	MEGI	2018
9766554	British Contributor	BP	Daewoo	173400	Membrane	Conventional	MEGI	2018
9333620	British Diamond	BP	Hyundai	155000	Membrane	Conventional	DFDE	2008
9333591	British Emerald	BP	Hyundai	155000	Membrane	Conventional	DFDE	2007
9766566	British Listener	BP	Daewoo	174000	Membrane	Conventional	MEGI	2019
9766578	British Mentor	BP	Daewoo	174000	Membrane	Conventional	MEGI	2019
9766530	British Partner	BP	Daewoo	173400	Membrane	Conventional	MEGI	2018
9333606	British Ruby	BP	Hyundai	155000	Membrane	Conventional	DFDE	2008
9333618	British Sapphire	BP	Hyundai	155000	Membrane	Conventional	DFDE	2008
9766580	British Sponsor	BP	Daewoo	174000	Membrane	Conventional	MEGI	2019
9085651	Broog	J4	Mitsui	137500	Spherical	Conventional	Steam	1998
9388833	Bu Samra	Nakilat	Samsung	266000	Membrane	Q-Max	SSDR	2008
9796793	Bushu Maru	NYK, JERA	Mitsubishi	180000	Spherical	Conventional	STaGE	2019
9230062	BW Boston	BW, Total	Daewoo	138000	Membrane	Conventional	Steam	2003
9368314	BW Brussels	BW	Daewoo	162500	Membrane	Conventional	DFDE	2009
9243148	BW Everett	BW	Daewoo	138000	Membrane	Conventional	Steam	2003
9724946	BW Integrity	BW, MOL	Samsung	173500	Membrane	FSRU	TFDE	2017
9758076	BW Lilac	BW	Daewoo	173400	Membrane	Conventional	MEGI	2018
9792591	BW Magna	BW	Daewoo	173400	Membrane	FSRU	TFDE	2019
9368302	BW Paris	BW	Daewoo	162400	Membrane	Converted FSRU	TFDE	2009
9792606	BW Pavilion Aranda	BW, Pavilion LNG	Daewoo	173400	Membrane	Conventional	MEGI	2019
9640645	BW Pavilion Leeara	BW, Pavilion LNG	Hyundai	162000	Membrane	Conventional	TFDE	2015
9640437	BW Pavilion Vanda	BW, Pavilion LNG	Hyundai	162000	Membrane	Conventional	TFDE	2015
9684495	BW Singapore	BW	Samsung	170200	Membrane	FSRU	TFDE	2015
9758064	BW Tulip	BW	Daewoo	173400	Membrane	Conventional	MEGI	2018
9246578	Cadiz Knutsen	Knutsen OAS	IZAR	138000	Membrane	Conventional	Steam	2004
9390680	Cape Ann	Hoegh, MOL, TLTC	Samsung	145000	Membrane	FSRU	DFDE	2010
9742819	Castillo De Caldelas	Caldelas LNG Shipping LTD	Imabari	178800	Membrane	Conventional	MEGI	2018

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9742807	Castillo De Merida	Merida LNG Shipping LTD	Imabari	178800	Membrane	Conventional	MEGI	2018
9433717	Castillo De Santisteban	Jofre Shipping LTD	STX	173600	Membrane	Conventional	TFDE	2010
9236418	Castillo De Villalba	Elcano Gas Transport, S.A.U.	IZAR	138200	Membrane	Conventional	Steam	2003
9236420	Catalunya Spirit	Teekay	IZAR	138200	Membrane	Conventional	Steam	2003
9672844	Cesi Beihai	China Shipping Group	Hudong-Zhonghua	174100	Membrane	Conventional	TFDE	2017
9672820	Cesi Gladstone	Chuo Kaiun/ Shinwa Chem.	Hudong-Zhonghua	174100	Membrane	Conventional	DFDE	2016
9672818	Cesi Lianyungang	China Shipping Group	Hudong-Zhonghua	174100	Membrane	Conventional	DFDE	2018
9672832	Cesi Qingdao	China Shipping Group	Hudong-Zhonghua	174100	Membrane	Conventional	DFDE	2017
9694749	Cesi Tianjin	China Shipping Group	Hudong-Zhonghua	174100	Membrane	Conventional	DFDE	2017
9694751	Cesi Wenzhou	China Shipping Group	Hudong-Zhonghua	174100	Membrane	Conventional	TFDE	2018
9324344	Cheikh Bouamama	HYPROC, Sonatrach, Itochu, MOL	Universal	75500	Membrane	Conventional	Steam	2008
9324332	Cheikh El Mokrani	HYPROC, Sonatrach, Itochu, MOL	Universal	75500	Membrane	Conventional	Steam	2007
9737187	Christophe De Margerie	Sovcomflot	Daewoo	172600	Membrane	Icebreaker	TFDE	2016
9323687	Clean Energy	Dynagas	Hyundai	149700	Membrane	Conventional	Steam	2007
9655444	Clean Horizon	Dynagas	Hyundai	162000	Membrane	Conventional	TFDE	2015
9637492	Clean Ocean	Dynagas	Hyundai	162000	Membrane	Conventional	TFDE	2014
9637507	Clean Planet	Dynagas	Hyundai	162000	Membrane	Conventional	TFDE	2014
9655456	Clean Vision	Dynagas	Hyundai	162000	Membrane	Conventional	TFDE	2016
9640023	Cool Explorer	Thenamaris	Samsung	160000	Membrane	Conventional	TFDE	2015
9636797	Cool Runner	Thenamaris	Samsung	160000	Membrane	Conventional	TFDE	2014
9636785	Cool Voyager	Thenamaris	Samsung	160000	Membrane	Conventional	TFDE	2013
9636711	Corcovado LNG	TMS Cardiff Gas	Daewoo	160100	Membrane	Conventional	TFDE	2014
9681687	Creole Spirit	Teekay	Daewoo	173000	Membrane	Conventional	MEGI	2016
9491812	Cubal	Mitsui, NYK, Teekay	Samsung	160000	Membrane	Conventional	TFDE	2012
9376294	Cygnus Passage	TEPCO, NYK, Mitsubishi	Mitsubishi	147000	Spherical	Conventional	Steam	2009
9308481	Dapeng Moon	China LNG Ship MgMT	Hudong-Zhonghua	147200	Membrane	Conventional	Steam	2008
9369473	Dapeng Star	China LNG Ship MgMT	Hudong-Zhonghua	147600	Membrane	Conventional	Steam	2009
9308479	Dapeng Sun	China LNG Ship MgMT	Hudong-Zhonghua	147200	Membrane	Conventional	Steam	2008
9779226	Diamond Gas Orchid	NYK	Mitsubishi	165000	Spherical	Conventional	STaGE	2018
9779238	Diamond Gas Rose	NYK	Mitsubishi	165000	Spherical	Conventional	STaGE	2018
9810020	Diamond Gas Sakura	NYK	Mitsubishi	165000	Spherical	Conventional	STaGE	2019

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9250713	Disha	MOL, NYK, K Line, SCI, Nakilat, Petronet	Daewoo	138100	Membrane	Conventional	Steam	2004
9085637	Doha	J4 Consortium	Mitsubishi	137300	Spherical	Conventional	Steam	1999
9337975	Duhail	Commerz Real, Nakilat, PRONAV	Daewoo	210200	Membrane	Q-Flex	SSDR	2008
9265500	Dukhan	J4 Consortium	Mitsui	137500	Spherical	Conventional	Steam	2004
9750696	Eduard Toll	Teekay	Daewoo	172600	Membrane	Icebreaker	TFDE	2017
9334076	Ejnan	K Line, MOL, NYK, Mitsui, Nakilat	Samsung	145000	Membrane	Conventional	Steam	2007
8706155	Ekaputra 1	P.T. Humpuss Trans	Mitsubishi	137000	Spherical	Conventional	Steam	1990
9269180	Energy Advance	Tokyo Gas	Kawasaki	147000	Spherical	Conventional	Steam	2005
9649328	Energy Atlantic	Alpha Tankers	STX	159700	Membrane	Conventional	TFDE	2015
9405588	Energy Confidence	Tokyo Gas, NYK	Kawasaki	155000	Spherical	Conventional	Steam	2009
9245720	Energy Frontier	Tokyo Gas	Kawasaki	147000	Spherical	Conventional	Steam	2003
9752565	Energy Glory	NYK, Tokyo Gas	Japan Marine	165000	Self-Supporting Prismatic	Conventional	TFDE	2019
9483877	Energy Horizon	NYK, TLTC	Kawasaki	177000	Spherical	Conventional	Steam	2011
9758832	Energy Innovator	MOL, Tokyo Gas	Japan Marine	165000	Self-Supporting Prismatic	Conventional	TFDE	2019
9736092	Energy Liberty	MOL, Tokyo Gas	Japan Marine	165000	Self-Supporting Prismatic	Conventional	TFDE	2018
9355264	Energy Navigator	Tokyo Gas, MOL	Kawasaki	147000	Spherical	Conventional	Steam	2008
9274226	Energy Progress	MOL	Kawasaki	147000	Spherical	Conventional	Steam	2006
9758844	Energy Universe	MOL, Tokyo Gas	Japan Marine	165000	Self-Supporting Prismatic	Conventional	TFDE	2019
9749609	Enshu Maru	K Line	Kawasaki	164700	Spherical	Conventional	Steam Reheat	2018
9666560	Esshu Maru	MOL, Tokyo Gas	Mitsubishi	153000	Spherical	Conventional	Steam	2014
9230050	Excalibur	Excelerate, Teekay	Daewoo	138000	Membrane	Conventional	Steam	2002
9252539	Excellence	Excelerate Energy	Daewoo	138000	Membrane	FSRU	Steam	2005
9239616	Excelsior	Excelerate Energy	Daewoo	138000	Membrane	FSRU	Steam	2005
9444649	Exemplar	Excelerate Energy	Daewoo	150900	Membrane	FSRU	Steam	2010
9389643	Expedient	Excelerate Energy	Daewoo	150900	Membrane	FSRU	Steam	2010
9638525	Experience	Excelerate Energy	Daewoo	173400	Membrane	FSRU	TFDE	2014
9361079	Explorer	Excelerate Energy	Daewoo	150900	Membrane	FSRU	Steam	2008

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9361445	Express	Excelerate Energy	Daewoo	150900	Membrane	FSRU	Steam	2009
9381134	Exquisite	Excelerate, Nakilat	Daewoo	150900	Membrane	FSRU	Steam	2009
9768370	Fedor Litke	LITKE	Daewoo	172600	Membrane	Icebreaker	TFDE	2017
9825427	Flex Constellation	Flex LNG	Daewoo	173400	Membrane	Conventional	MEGI	2019
9825439	Flex Courageous	Flex LNG	Daewoo	173400	Spherical	Conventional	MEGI	2019
9762261	Flex Endeavour	Flex LNG	Daewoo	173400	Membrane	Conventional	MEGI	2018
9762273	Flex Enterprise	Flex LNG	Daewoo	173400	Membrane	Conventional	MEGI	2018
9709037	Flex Rainbow	Flex LNG	Samsung	174000	Membrane	Conventional	MEGI	2018
9709025	Flex Ranger	Flex LNG	Samsung	174000	Membrane	Conventional	MEGI	2018
9360817	Fraiha	NYK, K Line, MOL, lino, Mitsui, Nakilat	Daewoo	210100	Membrane	Q-Flex	SSDR	2008
9253284	FSRU Toscana	OLT Offshore LNG Toscana	Hyundai	137100	Spherical	Converted FSRU		2004
9275359	Fuji LNG	TMS Cardiff Gas	Kawasaki	147900	Spherical	Conventional	Steam	2004
9256200	Fuwairit	MOL	Samsung	138262	Membrane	Conventional	Steam	2004
9236614	Galea	Shell	Mitsubishi	136600	Spherical	Conventional	Steam	2002
9247364	Galicia Spirit	Teekay	Daewoo	140500	Membrane	Conventional	Steam	2004
9236626	Gallina	Shell	Mitsubishi	136600	Spherical	Conventional	Steam	2002
9390185	Gaslog Chelsea	GasLog	Hanjin H.I.	153600	Membrane	Conventional	TFDE	2010
9707508	Gaslog Geneva	GasLog	Samsung	174000	Membrane	Conventional	TFDE	2016
9744013	Gaslog Genoa	GasLog	Samsung	174000	Membrane	Conventional	XDF	2018
9707510	Gaslog Gibraltar	GasLog	Samsung	174000	Membrane	Conventional	TFDE	2016
9744025	Gaslog Gladstone	Gaslog	Samsung	174000	Membrane	Conventional	XDF	2019
9687021	Gaslog Glasgow	GasLog	Samsung	174000	Membrane	Conventional	TFDE	2016
9687019	Gaslog Greece	GasLog	Samsung	174000	Membrane	Conventional	TFDE	2016
9748904	Gaslog Hongkong	GasLog	Hyundai	174000	Membrane	Conventional	XDF	2018
9748899	Gaslog Houston	GasLog	Hyundai	174000	Membrane	Conventional	XDF	2018
9638915	Gaslog Salem	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2015
9600530	Gaslog Santiago	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2013
9638903	Gaslog Saratoga	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2014
9352860	Gaslog Savannah	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2010
9634086	Gaslog Seattle	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2013
9600528	Gaslog Shanghai	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2013
9355604	Gaslog Singapore	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2010
9626285	Gaslog Skagen	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2013
9626273	Gaslog Sydney	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2013
9816763	Gaslog Warsaw	Gaslog	Samsung	180000	Membrane	Conventional	XDF	2019
9253222	Gemmata	Shell	Mitsubishi	135000	Spherical	Conventional	Steam	2004
9768382	Georgiy Brusilov	Dynagas	Daewoo	172600	Membrane	Icebreaker	TFDE	2018
9750749	Georgiy Ushakov	Teekay, China LNG Shipping	Daewoo	172000	Membrane	Icebreaker	TFDE	2019
9038452	Ghasha	National Gas Shipping Co	Mitsui	135000	Spherical	Conventional	Steam	1995
9360922	Gigira Laitebo	MOL, Itochu	Hyundai	155000	Membrane	Conventional	TFDE	2010
9269207	Global Energy	Total	Chantiers de l'Atlantique	74,100	Membrane	Conventional	Steam	2004

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9253105	Golar Arctic	Golar LNG	Daewoo	140000	Membrane	Conventional	Steam	2003
9626039	Golar Bear	Golar LNG	Samsung	160000	Membrane	Conventional	TFDE	2014
9626027	Golar Celsius	Golar Power	Samsung	160000	Membrane	Conventional	TFDE	2013
9624926	Golar Crystal	Golar LNG	Samsung	160000	Membrane	Conventional	TFDE	2014
9624940	Golar Eskimo	Golar LNG Partners	Samsung	160000	Membrane	FSRU	TFDE	2014
7361922	Golar Freeze	Golar LNG Partners	HDW	125000	Spherical	Converted FSRU	Steam	1977
9655042	Golar Frost	Golar LNG	Samsung	160000	Membrane	Conventional	TFDE	2014
9654696	Golar Glacier	Golar LNG	Hyundai	162000	Membrane	Conventional	TFDE	2014
9303560	Golar Grand	Golar LNG Partners	Daewoo	145000	Membrane	Conventional	Steam	2005
9637325	Golar Ice	Golar LNG	Samsung	160000	Membrane	Conventional	TFDE	2015
9633991	Golar Igloo	Golar LNG Partners	Samsung	170000	Membrane	FSRU	TFDE	2014
9654701	Golar Kelvin	Golar LNG	Hyundai	162000	Membrane	Conventional	TFDE	2015
9320374	Golar Maria	Golar LNG Partners	Daewoo	145000	Membrane	Conventional	Steam	2006
9165011	Golar Mazo	Golar LNG Partners	Mitsubishi	135000	Spherical	Conventional	Steam	2000
9785500	Golar Nanook	Golar Power	Samsung	170000	Membrane	FSRU	DFDE	2018
9624938	Golar Penguin	Golar Power	Samsung	160000	Membrane	Conventional	TFDE	2014
9624914	Golar Seal	Golar LNG	Samsung	160000	Membrane	Conventional	TFDE	2013
9635315	Golar Snow	Golar LNG	Samsung	160000	Membrane	Conventional	TFDE	2015
9655808	Golar Tundra	Golar LNG	Samsung	170000	Membrane	FSRU	TFDE	2015
9256614	Golar Winter	Golar LNG Partners	Daewoo	138000	Membrane	Converted FSRU	Steam	2004
9315707	Grace Acacia	NYK	Hyundai	150000	Membrane	Conventional	Steam	2007
9315719	Grace Barleria	NYK	Hyundai	150000	Membrane	Conventional	Steam	2007
9323675	Grace Cosmos	MOL, NYK	Hyundai	150000	Membrane	Conventional	Steam	2008
9540716	Grace Dahlia	NYK	Kawasaki	177400	Spherical	Conventional	Steam	2013
8702941	Grace Energy	Sinokor Merchant Marine	Mitsubishi	127,400	Spherical	Conventional	Steam	1989
9338955	Grand Aniva	NYK, Sovcomflot	Mitsubishi	147000	Spherical	Conventional	Steam	2008
9332054	Grand Elena	NYK, Sovcomflot	Mitsubishi	147000	Spherical	Conventional	Steam	2007
9338929	Grand Mereya	MOL, K Line, Primorsk	Mitsui	147600	Spherical	Conventional	Steam	2008
9696266	Hai Yang Shi You 301	CNOOC	Jiangnan	30422	Membrane	Conventional	DFDE	2015
9230048	Hispania Spirit	Teekay	Daewoo	140500	Membrane	Conventional	Steam	2002
9155078	HL Muscat	Hanjin Shipping Co.	Hanjin H.I.	138000	Membrane	Conventional	Steam	1999
9061928	HL Pyeongtaek	Hanjin Shipping Co.	Hanjin H.I.	130100	Membrane	Conventional	Steam	1995
9176008	HL Ras Laffan	Hanjin Shipping Co.	Hanjin H.I.	138000	Membrane	Conventional	Steam	2000
9176010	HL Sur	Hanjin Shipping Co.	Hanjin H.I.	138300	Membrane	Conventional	Steam	2000
9780354	Hoegh Esperanza	Hoegh	Hyundai	170000	Membrane	FSRU	DFDE	2018
9653678	Hoegh Gallant	Hoegh	Hyundai	170100	Membrane	FSRU	DFDE	2014

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9820013	Hoegh Galleon	Hoegh	Samsung	170000	Membrane	FSRU	TFDE	2019
9822451	Hoegh Gannet	Hoegh	Hyundai	170000	Membrane	FSRU	DFDE	2018
9762962	Hoegh Giant	Hoegh	Hyundai	170000	Membrane	FSRU	DFDE	2017
9674907	Hoegh Grace	Hoegh	Hyundai	170000	Membrane	FSRU	DFDE	2016
9250725	Hongkong Energy	Sinokor Merchant Marine	Daewoo	140500	Membrane	Conventional	Steam	2004
9179581	Hyundai Aquapia	Hyundai LNG Shipping	Hyundai	135000	Spherical	Conventional	Steam	2000
9155157	Hyundai Cosmopia	Hyundai LNG Shipping	Hyundai	135000	Spherical	Conventional	Steam	2000
9372999	Hyundai Ecopia	Hyundai LNG Shipping	Hyundai	150000	Membrane	Conventional	Steam	2008
9075333	Hyundai Greenpia	Hyundai LNG Shipping	Hyundai	125000	Spherical	Conventional	Steam	1996
9183269	Hyundai Oceanpia	Hyundai LNG Shipping	Hyundai	135000	Spherical	Conventional	Steam	2000
9761853	Hyundai Peacepia	Hyundai LNG Shipping	Daewoo	174000	Membrane	Conventional	MEGI	2017
9761841	Hyundai Princepia	Hyundai LNG Shipping	Daewoo	174000	Membrane	Conventional	MEGI	2017
9155145	Hyundai Technopia	Hyundai LNG Shipping	Hyundai	135000	Spherical	Conventional	Steam	1999
9018555	Hyundai Utopia	Hyundai LNG Shipping	Hyundai	125200	Spherical	Conventional	Steam	1994
9326603	Iberica Knutsen	Knutsen OAS	Daewoo	138000	Membrane	Conventional	Steam	2006
9326689	Ibra LNG	OSC, MOL	Samsung	147600	Membrane	Conventional	Steam	2006
9317315	Ibri LNG	OSC, MOL, Mitsubishi	Mitsubishi	147600	Spherical	Conventional	Steam	2006
9629536	Independence	Hoegh	Hyundai	170100	Membrane	FSRU	DFDE	2014
9035864	Ish	National Gas Shipping Co	Mitsubishi	137300	Spherical	Conventional	Steam	1995
9157636	K. Acacia	Korea Line	Daewoo	138000	Membrane	Conventional	Steam	2000
9186584	K. Freesia	Korea Line	Daewoo	138000	Membrane	Conventional	Steam	2000
9373008	K. Jasmine	Korea Line	Daewoo	145700	Membrane	Conventional	Steam	2008
9373010	K. Mugungwha	Korea Line	Daewoo	151700	Membrane	Conventional	Steam	2008
9785158	Kinisis	Chandris Group	Daewoo	173400	Membrane	Conventional	MEGI	2018
9636723	Kita LNG	TMS Cardiff Gas	Daewoo	160100	Membrane	Conventional	TFDE	2014
9613161	Kumul	MOL, China LNG	Hudong-Zhonghua	172000	Membrane	Conventional	SSDR	2016
9721724	La Mancha Knutsen	Knutsen OAS	Hyundai	176000	Membrane	Conventional	MEGI	2016
9275347	Lalla Fatma N'soumer	HYPROC	Kawaski	147300	Spherical	Conventional	Steam	2004
9629598	Lena River	Dynagas	Hyundai	155000	Membrane	Conventional	DFDE	2013
9064085	Lerici	ENI	Sestri	65300	Membrane	Conventional	Steam	1998
9388819	Lijmiliya	Nakilat	Daewoo	263300	Membrane	Q-Max	SSDR	2009
9690171	LNG Abalamabie	BGT Ltd.	Samsung	175000	Membrane	Conventional	DFDE	2016
9690169	LNG Abuja II	BGT LTD	Samsung	175000	Membrane	Conventional	DFDE	2016
9262211	LNG Adamawa	BGT Ltd.	Hyundai	141000	Spherical	Conventional	Steam	2005
9262209	LNG Akwa Ibom	BGT Ltd.	Hyundai	141000	Spherical	Conventional	Steam	2004
9320075	LNG Alliance	Gazocean	Chantiers de l'Atlantique	154500	Membrane	Conventional	DFDE	2007

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
7390181	LNG Aquarius	Hanochem	General Dynamics	126300	Spherical	Conventional	Steam	1977
9341299	LNG Barka	OSC, OG, NYK, K Line	Kawasaki	153600	Spherical	Conventional	Steam	2008
9241267	LNG Bayelsa	BGT Ltd.	Hyundai	137000	Spherical	Conventional	Steam	2003
9267015	LNG Benue	BW	Daewoo	145700	Membrane	Conventional	Steam	2006
9692002	LNG Bonny II	BGT LTD	Hyundai	177000	Membrane	Conventional	DFDE	2015
9322803	LNG Borno	NYK	Samsung	149600	Membrane	Conventional	Steam	2007
9262223	LNG Cross River	BGT Ltd.	Hyundai	141000	Spherical	Conventional	Steam	2005
9277620	LNG Dream	NYK	Kawasaki	145300	Spherical	Conventional	Steam	2006
9834296	LNG Dubhe	MOL, COSCO	Hudong-Zhonghua	174000	Membrane	Conventional	XDF	2019
9329291	LNG Ebisu	MOL, KEPCO	Kawasaki	147500	Spherical	Conventional	Steam	2008
9266994	LNG Enugu	BW	Daewoo	145000	Membrane	Conventional	Steam	2005
9690145	LNG Finima II	BGT Ltd.	Samsung	175000	Membrane	Conventional	DFDE	2015
9666986	LNG Fukurokuju	MOL, KPCO	Kawasaki	165100	Spherical	Conventional	Steam Reheat	2016
9311581	LNG Imo	BW	Daewoo	148500	Membrane	Conventional	Steam	2008
9200316	LNG Jamal	NYK, Osaka Gas	Mitsubishi	137000	Spherical	Conventional	Steam	2000
9774628	LNG Juno	MOL	Mitsubishi	177300	Spherical	Conventional	STaGE	2018
9341689	LNG Jupiter	Osaka Gas, NYK	Kawasaki	156000	Spherical	Conventional	Steam	2009
9666998	LNG Jurojin	MOL, KEPCO	Mitsubishi	155300	Spherical	Conventional	Steam Reheat	2015
9311567	LNG Kano	BW	Daewoo	148300	Membrane	Conventional	Steam	2007
9372963	LNG Kolt	STX Pan Ocean	Hanjin H.I.	153000	Membrane	Conventional	Steam	2008
9692014	LNG Lagos II	BGT Ltd.	Hyundai	177000	Membrane	Conventional	DFDE	2016
9269960	LNG Lokoja	BW	Daewoo	148300	Membrane	Conventional	Steam	2006
8701791	LNG Maleo	MOL, NYK, K Line	Mitsui	127700	Spherical	Conventional	Steam	1989
9645748	LNG Mars	Osaka Gas, MOL	Mitsubishi	155000	Spherical	Conventional	Steam Reheat	2016
9322815	LNG Ogun	NYK	Samsung	149600	Membrane	Conventional	Steam	2007
9311579	LNG Ondo	BW	Daewoo	148300	Membrane	Conventional	Steam	2007
9267003	LNG Oyo	BW	Daewoo	145800	Membrane	Conventional	Steam	2005
9256602	LNG Pioneer	MOL	Daewoo	138000	Membrane	Conventional	Steam	2005
9690157	LNG Port-Harcourt II	BGT Ltd.	Samsung	175000	Membrane	Conventional	DFDE	2015
9262235	LNG River Niger	BGT Ltd.	Hyundai	141000	Spherical	Conventional	Steam	2006
9266982	LNG River Orashi	BW	Daewoo	145900	Membrane	Conventional	Steam	2004
9216298	LNG Rivers	BGT Ltd.	Hyundai	137000	Spherical	Conventional	Steam	2002
9774135	LNG Sakura	NYK/Kepco	Kawasaki	177000	Spherical	Conventional	TFDE	2018
9696149	LNG Saturn	MOL	Mitsubishi	155700	Spherical	Conventional	Steam Reheat	2016
9771913	LNG Schneeweisschen	MOL	Daewoo	180000	Membrane	Conventional	XDF	2018
9216303	LNG Sokoto	BGT Ltd.	Hyundai	137000	Spherical	Conventional	Steam	2002
9306495	LNG Unity	TOTAL	Chantiers de l'Atlantique	154500	Membrane	Conventional	DFDE	2006
9645736	LNG Venus	Osaka Gas, MOL	Mitsubishi	155000	Spherical	Conventional	Steam	2014
9020766	LNG Vesta	Tokyo Gas, MOL, lino	Mitsubishi	127000	Spherical	Conventional	Steam	1994

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9490961	Lobito	Mitsui, NYK, Teekay	Samsung	160400	Membrane	Conventional	TFDE	2011
9285952	Lusail	K Line, MOL, NYK, Nakilat	Samsung	145700	Membrane	Conventional	Steam	2005
9705653	Macoma	Teekay	Daewoo	173000	Membrane	Conventional	MEGI	2017
9259276	Madrid Spirit	Teekay	IZAR	138000	Membrane	Conventional	Steam	2004
9770921	Magdala	Teekay	Daewoo	173000	Membrane	Conventional	MEGI	2018
9342487	Magellan Spirit	Teekay, Marubeni	Samsung	165500	Membrane	Conventional	DFDE	2009
9490959	Malanje	Mitsui, NYK, Teekay	Samsung	160400	Membrane	Conventional	DFDE	2011
9682588	Maran Gas Achilles	Maran Gas Maritime	Hyundai	174000	Membrane	Conventional	DFDE	2015
9682590	Maran Gas Agamemnon	Maran Gas Maritime	Hyundai	174000	Membrane	Conventional	MEGI	2016
9650054	Maran Gas Alexandria	Maran Gas Maritime	Hyundai	161900	Membrane	Conventional	DFDE	2015
9701217	Maran Gas Amphipolis	Maran Gas Maritime	Daewoo	173400	Membrane	Conventional	DFDE	2016
9810379	Maran Gas Andros	Maran Gas Maritime	Daewoo	173400	Membrane	Conventional	MEGI	2019
9633422	Maran Gas Apollonia	Maran Gas Maritime	Hyundai	161900	Membrane	Conventional	DFDE	2014
9302499	Maran Gas Asclepius	Maran G.M, Nakilat	Daewoo	145800	Membrane	Conventional	Steam	2005
9753014	Maran Gas Chios	Maran Gas Maritime	Daewoo	173400	Membrane	Conventional	MEGI	2019
9331048	Maran Gas Coronis	Maran G.M, Nakilat	Daewoo	145700	Membrane	Conventional	Steam	2007
9633173	Maran Gas Delphi	Maran Gas Maritime	Daewoo	159800	Membrane	Conventional	TFDE	2014
9627497	Maran Gas Efessos	Maran Gas Maritime	Daewoo	159800	Membrane	Conventional	DFDE	2014
9682605	Maran Gas Hector	Maran Gas Maritime	Hyundai	174000	Membrane	Conventional	DFDE	2016
9767962	Maran Gas Hydra	Maran Gas Maritime	Daewoo	173400	Membrane	Conventional	MEGI	2019
9682576	Maran Gas Leto	Maran Gas Maritime	Hyundai	174000	Membrane	Conventional	DFDE	2016
9627502	Maran Gas Lindos	Maran Gas Maritime	Daewoo	159800	Membrane	Conventional	DFDE	2015
9658238	Maran Gas Mystras	Maran Gas Maritime	Daewoo	159800	Membrane	Conventional	DFDE	2015
9732371	Maran Gas Olympias	Maran Gas Maritime	Daewoo	173400	Membrane	Conventional	TFDE	2017
9709489	Maran Gas Pericles	Maran Gas Maritime	Hyundai	174000	Membrane	Conventional	DFDE	2016
9633434	Maran Gas Posidonia	Maran Gas Maritime	Hyundai	161900	Membrane	Conventional	DFDE	2014
9701229	Maran Gas Roxana	Maran Gas Maritime	Daewoo	173400	Membrane	Conventional	TFDE	2017
9650042	Maran Gas Sparta	Maran Gas Maritime	Hyundai	161900	Membrane	Conventional	TFDE	2015
9767950	Maran Gas Spetses	Maran G.M, Nakilat	Daewoo	173400	Membrane	Conventional	MEGI	2018
9658240	Maran Gas Troy	Maran Gas Maritime	Daewoo	159800	Membrane	Conventional	TFDE	2015

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9709491	Maran Gas Ulysses	Maran Gas Maritime	Hyundai	174000	Membrane	Conventional	TFDE	2017
9732369	Maran Gas Vergina	Maran Gas Maritime	Daewoo	173400	Membrane	Conventional	TFDE	2016
9659725	Maria Energy	Tsakos	Hyundai	174000	Membrane	Conventional	TFDE	2016
9336749	Marib Spirit	Teekay	Samsung	165500	Membrane	Conventional	DFDE	2008
9778313	Marshal Vasilevskiy	Gazprom JSC	Hyundai	174000	Membrane	FSRU	TFDE	2018
9770438	Marvel Crane	NYK	Mitsubishi	177000	Spherical	Conventional	STaGE	2019
9759240	Marvel Eagle	MOL	Kawasaki	155000	Spherical	Conventional	TFDE	2018
9760768	Marvel Falcon	MOL	Samsung	174000	Membrane	Conventional	XDF	2018
9760770	Marvel Hawk	MOL	Samsung	174000	Membrane	Conventional	XDF	2018
9770440	Marvel Heron	MOL	Mitsubishi	177000	Spherical	Conventional	STaGE	2019
9760782	Marvel Kite	MOL	Samsung	174000	Membrane	Conventional	XDF	2019
9759252	Marvel Pelican	MOL	Kawasaki	155985	Spherical	Conventional	TFDE	2019
9770945	Megara	Teekay	Daewoo	173000	Membrane	Conventional	MEGI	2018
9397303	Mekaines	Nakilat	Samsung	266500	Membrane	Q-Max	SSDR	2009
9250191	Merchant	Sinokor Merchant Marine	Samsung	138200	Membrane	Conventional	Steam	2003
9369904	Meridian Spirit	Teekay, Marubeni	Samsung	165500	Membrane	Conventional	DFDE	2010
9337729	Mesaimeer	Nakilat	Hyundai	216300	Membrane	Q-Flex	SSDR	2009
9321768	Methane Alison Victoria	GasLog	Samsung	145000	Membrane	Conventional	Steam	2007
9516129	Methane Becki Anne	GasLog	Samsung	170000	Membrane	Conventional	TFDE	2010
9321744	Methane Heather Sally	GasLog	Samsung	145000	Membrane	Conventional	Steam	2007
9307190	Methane Jane Elizabeth	GasLog	Samsung	145000	Membrane	Conventional	Steam	2006
9412880	Methane Julia Louise	MOL	Samsung	170000	Membrane	Conventional	TFDE	2010
9256793	Methane Kari Elin	Shell	Samsung	138000	Membrane	Conventional	Steam	2004
9307205	Methane Lydon Volney	GasLog	Samsung	145000	Membrane	Conventional	Steam	2006
9520376	Methane Mickie Harper	Shell	Samsung	170000	Membrane	Conventional	TFDE	2010
9321770	Methane Nile Eagle	Shell, Gaslog	Samsung	145000	Membrane	Conventional	Steam	2007
9425277	Methane Patricia Camila	Shell	Samsung	170000	Membrane	Conventional	TFDE	2010
9253715	Methane Princess	Golar LNG Partners	Daewoo	138000	Membrane	Conventional	Steam	2003
9307188	Methane Rita Andrea	Shell, Gaslog	Samsung	145000	Membrane	Conventional	Steam	2006
9321756	Methane Shirley Elisabeth	Shell, Gaslog	Samsung	145000	Membrane	Conventional	Steam	2007
9336737	Methane Spirit	Teekay, Marubeni	Samsung	165500	Membrane	Conventional	TFDE	2008
9321732	Milaha Qatar	Nakilat, Qatar Shpg., SocGen	Samsung	145600	Membrane	Conventional	Steam	2006
9255854	Milaha Ras Laffan	Nakilat, Qatar Shpg., SocGen	Samsung	138270	Membrane	Conventional	Steam	2004
9305128	Min Lu	China LNG Ship MgMT.	Hudong-Zhonghua	147200	Membrane	Conventional	Steam	2009

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9305116	Min Rong	China LNG Ship MgMT.	Hudong-Zhonghua	147600	Membrane	Conventional	Steam	2009
9713105	MOL FSRU Challenger	MOL	Daewoo	263000	Membrane	FSRU	TFDE	2017
9337755	Mozah	Nakilat	Samsung	266300	Membrane	Q-Max	SSDR	2008
9074638	Mraweh	National Gas Shipping Co	Kvaerner Masa	135000	Spherical	Conventional	Steam	1996
9074626	Mubaraz	National Gas Shipping Co	Kvaerner Masa	135000	Spherical	Conventional	Steam	1996
9705641	Murex	Teekay	Daewoo	173000	Membrane	Conventional	MEGI	2017
9360805	Murwab	NYK, K Line, MOL, lino, Mitsui, Nakilat	Daewoo	210100	Membrane	Q-Flex	SSDR	2008
9770933	Myrina	Teekay	Daewoo	173000	Membrane	Conventional	MEGI	2018
9324277	Neo Energy	Tsakos	Hyundai	150000	Spherical	Conventional	Steam	2007
9385673	Neptune	Hoegh, MOL, TLTC	Samsung	145000	Membrane	FSRU	DFDE	2009
9750660	Nikolay Urvantsev	MOL, COSCO	Daewoo	172000	Membrane	Icebreaker	TFDE	2019
9750725	Nikolay Yevgenov	Teekay, China LNG Shipping	Daewoo	172000	Membrane	Icebreaker	TFDE	2019
9768526	Nikolay Zubov	Dynagas	Daewoo	172000	Membrane	Icebreaker	TFDE	2019
9294264	Nizwa LNG	OSC, MOL	Kawasaki	147700	Spherical	Conventional	Steam	2005
9796781	Nohshu Maru	MOL, JERA	Mitsubishi	177300	Spherical	Conventional	STaGE	2019
8608872	Northwest Sanderling	North West Shelf Venture	Mitsubishi	126700	Spherical	Conventional	Steam	1989
8913150	Northwest Sandpiper	North West Shelf Venture	Mitsui	127000	Spherical	Conventional	Steam	1993
8608884	Northwest Snipe	North West Shelf Venture	Mitsui	126900	Spherical	Conventional	Steam	1990
9045132	Northwest Stormpetrel	North West Shelf Venture	Mitsubishi	126800	Spherical	Conventional	Steam	1994
7382744	Nusantara Regas Satu	Golar LNG Partners	Rosenberg Verft	125003	Spherical	Converted FSRU	Steam	1977
9681699	Oak Spirit	Teekay	Daewoo	173000	Membrane	Conventional	MEGI	2016
9315692	Ob River	Dynagas	Hyundai	149700	Membrane	Conventional	Steam	2007
9698111	Oceanic Breeze	K-Line, Inpex	Mitsubishi	155300	Spherical	Conventional	Steam Reheat	2018
9397353	Onaiza	Nakilat	Daewoo	210200	Membrane	Q-Flex	SSDR	2009
9761267	Ougarta	HYPROC	Hyundai	171800	Membrane	Conventional	TFDE	2017
9621077	Pacific Arcadia	NYK	Mitsubishi	145400	Spherical	Conventional	Steam	2014
9698123	Pacific Breeze	K Line	Kawasaki	182000	Spherical	Conventional	TFDE	2018
9351971	Pacific Enlighten	Kyushu Electric, TEPCO, Mitsubishi, Mitsui, NYK, MOK	Mitsubishi	145000	Spherical	Conventional	Steam	2009
9264910	Pacific Eurus	TEPCO, NYK, Mitsubishi	Mitsubishi	137000	Spherical	Conventional	Steam	2006
9743875	Pacific Mimosa	NYK	Mitsubishi	155300	Membrane	Conventional	Steam Reheat	2018
9247962	Pacific Notus	TEPCO, NYK, Mitsubishi	Mitsubishi	137000	Spherical	Conventional	Steam	2003
9636735	Palu LNG	TMS Cardiff Gas	Daewoo	160000	Membrane	Conventional	TFDE	2014

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9750256	Pan Africa	Teekay, China LNG Shipping, CETS Investment Management, BW	Hudong-Zhonghua	174000	Membrane	Conventional	DFDE	2019
9750232	Pan Americas	Teekay	Hudong-Zhonghua	174000	Membrane	Conventional	DFDE	2018
9750220	Pan Asia	Teekay	Hudong-Zhonghua	174000	Membrane	Conventional	DFDE	2017
9750244	Pan Europe	Teekay	Hudong-Zhonghua	174000	Membrane	Conventional	DFDE	2018
9613135	Papua	MOL, China LNG	Hudong-Zhonghua	172000	Membrane	Conventional	SSDR	2015
9766889	Patris	Chandris Group	Daewoo	173400	Membrane	Conventional	MEGI	2018
9629524	PGN FSRU Lampung	Hoegh	Hyundai	170132	Membrane	FSRU	DFDE	2014
9375721	Point Fortin	MOL, Sumitomo, LNG JAPAN	Imabari	154200	Membrane	Conventional	Steam	2010
9001772	Polar Spirit	Teekay	I.H.I.	87300	Self-Supporting Prismatic	Conventional	Steam	1993
9064073	Portovenere	ENI	Sestri	65300	Membrane	Conventional	Steam	1996
9246621	Portovyy	Gazprom	Daewoo	138100	Membrane	Conventional	Steam	2003
9723801	Prachi	MOL, NYK, K Line, SCI, Nakilat, Petronet	Hyundai	173000	Membrane	Conventional	TFDE	2016
9810549	Prism Agility	SK Shipping	Hyundai	180000	Membrane	Conventional	XDF	2019
9810551	Prism Brilliance	SK Shipping	Hyundai	180000	Membrane	Conventional	XDF	2019
9630028	Pskov	Sovcomflot	STX	170200	Membrane	Conventional	DFDE	2014
9030814	Puteri Delima	MISC	Chantiers de l'Atlantique	130000	Membrane	Conventional	Steam	1995
9211872	Puteri Delima Satu	MISC	Mitsui	137500	Membrane	Conventional	Steam	2002
9248502	Puteri Firus Satu	MISC	Mitsubishi	137500	Membrane	Conventional	Steam	2004
9030802	Puteri Intan	MISC	Chantiers de l'Atlantique	130000	Membrane	Conventional	Steam	1994
9213416	Puteri Intan Satu	MISC	Mitsubishi	137500	Membrane	Conventional	Steam	2002
9261205	Puteri Mutiara Satu	MISC	Mitsui	137000	Membrane	Conventional	Steam	2005
9030826	Puteri Nilam	MISC	Chantiers de l'Atlantique	130000	Membrane	Conventional	Steam	1995
9229647	Puteri Nilam Satu	MISC	Mitsubishi	137500	Membrane	Conventional	Steam	2003
9030838	Puteri Zamrud	MISC	Chantiers de l'Atlantique	130000	Membrane	Conventional	Steam	1996
9245031	Puteri Zamrud Satu	MISC	Mitsui	137500	Membrane	Conventional	Steam	2004
9253703	Raahi	MOL, NYK, K Line, SCI, Nakilat, Petronet	Daewoo	138100	Membrane	Conventional	Steam	2004
7411961	Ramdane Abane	Sonatrach	Chantiers de l'Atlantique	126000	Membrane	Conventional	Steam	1981
9443413	Rasheeda	Nakilat	Samsung	266300	Membrane	Q-Max	MEGI	2010
9825568	Rias Baixas Knutsen	Knutsen OAS	Hyundai	180000	Membrane	Conventional	MEGI	2019

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9477593	Ribera Duero Knutsen	Knutsen OAS	Daewoo	173400	Membrane	Conventional	DFDE	2010
9721736	Rioja Knutsen	Knutsen OAS	Hyundai	176000	Membrane	Conventional	MEGI	2016
9750713	Rudolf Samoylovich	Teekay	Daewoo	172600	Membrane	Icebreaker	TFDE	2018
9769855	Saga Dawn	Landmark Capital	Xiamen Shipbuilding Industry	45000	Self-Supporting Prismatic	Conventional	DFDE	2019
9300817	Salalah LNG	OSC, MOL	Samsung	147000	Membrane	Conventional	Steam	2005
9654878	SCF Melampus	Sovcomflot	STX	170200	Membrane	Conventional	TFDE	2015
9654880	SCF Mitre	Sovcomflot	STX	170200	Membrane	Conventional	TFDE	2015
9781918	Sean Spirit	Teekay	Hyundai	174000	Membrane	Conventional	MEGI	2018
9666558	Seishu Maru	Mitsubishi, NYK, Chubu Electric	Mitsubishi	153000	Membrane	Conventional	Steam	2014
8014473	Senshu Maru	MOL, NYK, K Line	Mitsui	125800	Spherical	Conventional	Steam	1984
9293832	Seri Alam	MISC	Samsung	145700	Membrane	Conventional	Steam	2005
9293844	Seri Amanah	MISC	Samsung	145700	Membrane	Conventional	Steam	2006
9321653	Seri Anggun	MISC	Samsung	145700	Membrane	Conventional	Steam	2006
9321665	Seri Angkasa	MISC	Samsung	145700	Membrane	Conventional	Steam	2006
9329679	Seri Ayu	MISC	Samsung	145700	Membrane	Conventional	Steam	2007
9331634	Seri Bakti	MISC	Mitsubishi	152300	Membrane	Conventional	Steam	2007
9331660	Seri Balhaf	MISC	Mitsubishi	157000	Membrane	Conventional	TFDE	2009
9331672	Seri Balqis	MISC	Mitsubishi	152000	Membrane	Conventional	TFDE	2009
9331646	Seri Begawan	MISC	Mitsubishi	152300	Membrane	Conventional	Steam	2007
9331658	Seri Bijaksana	MISC	Mitsubishi	152300	Membrane	Conventional	Steam	2008
9714305	Seri Camar	PETRONAS	Hyundai	150200	Membrane	Conventional	Steam Reheat	2018
9714276	Seri Camellia	PETRONAS	Hyundai	150200	Membrane	Conventional	Steam Reheat	2016
9756389	Seri Cemara	PETRONAS	Hyundai	150200	Spherical	Conventional	Steam Reheat	2018
9714290	Seri Cempaka	PETRONAS	Hyundai	150200	Spherical	Conventional	MEGI	2017
9714288	Seri Cenderawasih	PETRONAS	Hyundai	150200	Spherical	Conventional	Steam Reheat	2017
9338797	Sestao Knutsen	Knutsen OAS	IZAR	138000	Membrane	Conventional	Steam	2007
9414632	Sevilla Knutsen	Knutsen OAS	Daewoo	173400	Membrane	Conventional	DFDE	2010
9418365	Shagra	Nakilat	Samsung	266300	Membrane	Q-Max	SSDR	2009
9035852	Shahamah	National Gas Shipping Co	Kawasaki	135000	Spherical	Conventional	Steam	1994
9583677	Shen Hai	China LNG, CNOOC, Shanghai LNG	Hudong-Zhonghua	147600	Membrane	Conventional	Steam	2012
9791200	Shinshu Maru	MOL	Kawasaki	177000	Spherical	Conventional	DFDE	2019
9320386	Simaisma	Maran G.M, Nakilat	Daewoo	145700	Membrane	Conventional	Steam	2006
9238040	Singapore Energy	Sinokor Merchant Marine	Samsung	138000	Membrane	Conventional	Steam	2003
9693161	SK Audace	SK Shipping, Marubeni	Samsung	180000	Membrane	Conventional	XDF	2017
9693173	SK Resolute	SK Shipping, Marubeni	Samsung	180000	Membrane	Conventional	XDF	2018

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
9761803	SK Serenity	SK Shipping	Samsung	174000	Membrane	Conventional	MEGI	2018
9761815	SK Spica	SK Shipping	Samsung	174000	Membrane	Conventional	MEGI	2018
9180231	SK Splendor	SK Shipping	Samsung	138200	Membrane	Conventional	Steam	2000
9180243	SK Stellar	SK Shipping	Samsung	138200	Membrane	Conventional	Steam	2000
9157624	SK Summit	SK Shipping	Daewoo	138000	Membrane	Conventional	Steam	1999
9247194	SK Sunrise	SK Shipping	Samsung	138200	Membrane	Conventional	Steam	2003
9157739	SK Supreme	SK Shipping	Samsung	138200	Membrane	Conventional	Steam	2000
9761827	SM Eagle	Korea Line	Daewoo	174000	Membrane	Conventional	MEGI	2017
9761839	SM Seahawk	Korea Line	Daewoo	174000	Membrane	Conventional	MEGI	2017
9210816	Sohar LNG	OSC, MOL	Mitsubishi	137200	Spherical	Conventional	Steam	2001
9791212	Sohshu Maru	MOL, JERA	Kawasaki	177269	Spherical	Conventional	DFDE	2019
9634098	Solaris	GasLog	Samsung	155000	Membrane	Conventional	TFDE	2014
9482304	Sonangol Benguela	Mitsui, Sonangol, Sojlitz	Daewoo	160000	Membrane	Conventional	Steam	2011
9482299	Sonangol Etosha	Mitsui, Sonangol, Sojlitz	Daewoo	160000	Membrane	Conventional	Steam	2011
9475600	Sonangol Sambizanga	Mitsui, Sonangol, Sojlitz	Daewoo	160000	Membrane	Conventional	Steam	2011
9613147	Southern Cross	MOL, China LNG	Hudong-Zhonghua	168423	Membrane	Conventional	SSDR	2015
9475208	Soyo	Mitsui, NYK, Teekay	Samsung	160400	Membrane	Conventional	DFDE	2011
9361639	Spirit Of Hela	MOL, Itochu	Hyundai	177000	Membrane	Conventional	DFDE	2009
9315393	Stena Blue Sky	Stena Bulk	Daewoo	145700	Membrane	Conventional	Steam	2006
9413327	Stena Clear Sky	Stena Bulk	Daewoo	173000	Membrane	Conventional	TFDE	2011
9383900	Stena Crystal Sky	Stena Bulk	Daewoo	173000	Membrane	Conventional	TFDE	2011
9322255	Summit LNG	Excelerate Energy	Daewoo	138000	Membrane	FSRU	Steam	2006
9330745	Symphonic Breeze	K Line	Kawasaki	147600	Spherical	Conventional	Steam	2007
9403669	Taitar No.1	CPC, Mitsui. NYK	Mitsubishi	145300	Spherical	Conventional	Steam	2009
9403645	Taitar No.2	MOL, NYK	Kawaski	145300	Spherical	Conventional	Steam	2009
9403671	Taitar No.3	MOL, NYK	Mitsubishi	145300	Spherical	Conventional	Steam	2010
9403657	Taitar No.4	CPC, Mitsui. NYK	Kawaski	145300	Spherical	Conventional	Steam	2010
9334284	Tangguh Batur	Sovcomflot, NYK	Daewoo	145700	Membrane	Conventional	Steam	2008
9349007	Tangguh Foja	K Line, PT Meratus	Samsung	154800	Membrane	Conventional	DFDE	2008
9333632	Tangguh Hiri	Teekay	Hyundai	155000	Membrane	Conventional	DFDE	2008
9349019	Tangguh Jaya	K Line, PT Meratus	Samsung	155000	Membrane	Conventional	DFDE	2008
9355379	Tangguh Palung	K Line, PT Meratus	Samsung	155000	Membrane	Conventional	DFDE	2009
9361990	Tangguh Sago	Teekay	Hyundai	155000	Membrane	Conventional	DFDE	2009
9325893	Tangguh Towuti	NYK, PT Samudera, Sovcomflot	Daewoo	145700	Membrane	Conventional	Steam	2008
9337731	Tembek	Nakilat, OSC	Samsung	216200	Membrane	Q-Flex	SSDR	2007
7428433	Tenaga Empat	MISC	CNIM	130000	Membrane	FSU	Steam	1981

Appendix 3: Table of Global Active LNG Fleet (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cm)	Cargo Type	Vessel Type	Propulsion Type	Delivery Year
7428457	Tenaga Satu	MISC	Dunkerque Chantiers	130000	Membrane	FSU	Steam	1982
9761243	Tessala	HYPROC	Hyundai	171800	Membrane	Conventional	TFDE	2016
9721401	Torben Spirit	Teekay	Daewoo	173000	Membrane	Conventional	MEGI	2017
9238038	Trader	Sinokor Merchant Marine	Samsung	138000	Membrane	Conventional	Steam	2002
9319404	Trinity Arrow	K Line	Imabari	155000	Membrane	Conventional	Steam	2008
9350927	Trinity Glory	K Line	Imabari	155000	Membrane	Conventional	Steam	2009
9823883	Turquoise P	Pardus Energy	Hyundai	170000	Membrane	FSRU	DFDE	2019
9360829	Umm Al Amad	NYK, K Line, MOL, lino, Mitsui, Nakilat	Daewoo	210200	Membrane	Q-Flex	SSDR	2008
9074652	Umm Al Ashtan	National Gas Shipping Co	Kvaerner Masa	135000	Spherical	Conventional	Steam	1997
9308431	Umm Bab	Maran G.M, Nakilat	Daewoo	145700	Membrane	Conventional	Steam	2005
9372731	Umm Slal	Nakilat	Samsung	266000	Membrane	Q-Max	SSDR	2008
9434266	Valencia Knutsen	Knutsen OAS	Daewoo	173400	Membrane	Conventional	DFDE	2010
9630004	Velikiy Novgorod	Sovcomflot	STX	170200	Membrane	Conventional	DFDE	2014
9750701	Vladimir Rusanov	MOL	Daewoo	172600	Membrane	Icebreaker	TFDE	2018
9750658	Vladimir Vize	MOL	Daewoo	172600	Membrane	Icebreaker	TFDE	2018
9750737	Vladimir Voronin	Teekay, China LNG Shipping	Daewoo	172000	Membrane	Icebreaker	TFDE	2019
9627954	Wilforce	Teekay	Daewoo	160000	Membrane	Conventional	TFDE	2013
9627966	Wilpride	Teekay	Daewoo	160000	Membrane	Conventional	TFDE	2013
9753026	Woodside Chaney	Maran Gas Maritime	Hyundai	173525	Membrane	Conventional	SSDR	2019
9369899	Woodside Donaldson	Teekay, Marubeni	Samsung	165500	Membrane	Conventional	DFDE	2009
9633161	Woodside Goode	Maran Gas Maritime	Daewoo	159800	Membrane	Conventional	DFDE	2013
9810367	Woodside Rees Wither	Maran Gas Maritime	Daewoo	173400	Membrane	Conventional	MEGI	2019
9627485	Woodside Rogers	Maran Gas Maritime	Daewoo	159800	Membrane	Conventional	DFDE	2013
9750672	Yakov Gakkel	Teekay, China LNG Shipping	Daewoo	172000	Membrane	Icebreaker	TFDE	2019
9781920	Yamal Spirit	Teekay	Hyundai	174000	Membrane	Conventional	MEGI	2019
9636747	Yari LNG	TMS Cardiff Gas	Daewoo	160000	Membrane	Conventional	TFDE	2014
9629586	Yenisei River	Dynagas	Hyundai	155000	Membrane	Conventional	DFDE	2013
9038816	YK Sovereign	SK Shipping	Hyundai	127100	Spherical	Conventional	Steam	1994
9431214	Zarga	Nakilat	Samsung	266000	Membrane	Q-Max	SSDR	2010
9132818	Zekreet	J4 Consortium	Mitsui	137500	Spherical	Conventional	Steam	1998

Source : Rystad Energy Research and Analysis

Appendix 4: Table of Global LNG Vessel Orderbook, Year-End 2019

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cbm)	Propulsion Type	Delivery Year
9850666	BW Magnolia	BW	Daewoo	174000	MEGI	2020
9850678	BW Pavilion Aramhera	BW	Daewoo	170799	MEGI	2020
9854624	Energy Endeavour	Alpha Gas	Daewoo	173400	MEGI	2020
9862308	Flex Freedom	Frontline Management	Daewoo	173400	MEGI	2020
9851634	Flex Reliance	FLEX LNG	Daewoo	173400	MEGI	2020
9851646	Flex Resolute	FLEX LNG	Daewoo	173400	MEGI	2020
9844863	Maran Gas Psara	Maran Gas Maritime	Daewoo	173400	MEGI	2020
9859753	Yiannis	Maran Gas Maritime	Daewoo	173400	MEGI	2020
9820843	Daewoo 2477	Maran Gas Maritime	Daewoo	173400	MEGI	2020
9845013	Daewoo 2478	Maran Gas Maritime	Daewoo	173400	MEGI	2020
9854363	Daewoo 2481	Minerva Marine	Daewoo	173400	MEGI	2021
9854375	Daewoo 2482	Minerva Marine	Daewoo	173400	MEGI	2021
9854612	Daewoo 2483	Alpha Gas	Daewoo	173400	MEGI	2020
9859739	Daewoo 2485	Alpha Gas	Daewoo	173400	MEGI	2021
9859741	Daewoo 2487	Maran Gas Maritime	Daewoo	173400	MEGI	2021
9873840	Daewoo 2496	BW	Daewoo	174000	MEGI	2021
9873852	Daewoo 2497	BW	Daewoo	174000	MEGI	2021
9877133	Daewoo 2498	MOL	Daewoo	174000	XDF	2021
9877145	Daewoo 2499	MOL	Daewoo	176523	XDF	2021
9881201	Daewoo 2500	Alpha Gas	Daewoo	173400	MEGI	2021
9879674	Daewoo 2501	Maran Gas Maritime	Daewoo		MEGI	2021
9880465	Daewoo 2502	Maran Gas Maritime	Daewoo		XDF	2021
9880477	Daewoo 2503	Maran Gas Maritime	Daewoo		XDF	2021
9883742	Daewoo 2504	Maran Gas Maritime	Daewoo		XDF	2021
9887217	Daewoo 2506	Maran Gas Maritime	Daewoo		XDF	2022
9892717	Daewoo 2507	Maran Gas Maritime	Daewoo		XDF	2021
9901350	Daewoo 2508		Daewoo			
9896921	Daewoo 2509	BW	Daewoo		MEGI	2022

Appendix 4: Table of Global LNG Vessel Orderbook (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cbm)	Propulsion Type	Delivery Year
9896933	Daewoo 2510	BW	Daewoo		MEGI	2022
9885996	Daewoo2505	MOL	Daewoo		XDF	2021
9834325	LNG Megrez	MOL	Hudong-Zhonghua	174000	XDF	2020
9834301	LNG Merak	MOL	Hudong-Zhonghua	174000	XDF	2020
9834313	LNG Phecda	MOL	Hudong-Zhonghua	174000	XDF	2020
9861809	Hudong Zhonghua H1786A	Dynagas	Hudong-Zhonghua	174300	DFDE/TFDE	2021
9861811	Hudong Zhonghua H1787A	Dynagas	Hudong-Zhonghua	174300	DFDE/TFDE	2021
9878876	Hudong Zhonghua H1827A	CSSC Shpg Leasing	Hudong-Zhonghua		XDF	2021
9878888	Hudong Zhonghua H1828A	CSSC Shpg Leasing	Hudong-Zhonghua		XDF	2021
9892121	Hudong Zhonghua H1829A		Hudong-Zhonghua			2022
9892133	Hudong Zhonghua H1830A		Hudong-Zhonghua			2022
9879698	Adamastos	Capital Gas	Hyundai	174000	XDF	2021
9845776	Amberjack LNG	TMS Cardiff Gas	Hyundai	174000	XDF	2020
9862920	Aristarchos	Capital Gas	Hyundai	174000	XDF	2021
9862906	Aristidis I	Capital Gas	Hyundai	174000	XDF	2020
9862891	Aristos I	Capital Gas	Hyundai	174000	XDF	2020
	Asklipios	Capital Gas	Hyundai	174000	XDF	2021
9884021	Asterix I	Capital Gas	Hyundai	174000	XDF	2021
9862918	Attalos	Capital Gas	Hyundai	174000	XDF	2021
9845788	Bonito LNG	TMS Cardiff Gas	Hyundai	174000	XDF	2020
9869306	Cobia LNG	TMS Cardiff Gas	Hyundai	174000	XDF	2021
9861031	Cool Discoverer	Thenamaris	Hyundai	174000	XDF	2020
9869265	Cool Racer	Thenamaris	Hyundai	174000	XDF	2021
9852975	Elisa Larus	N.Y.K. Line	Hyundai	174000	XDF	2020
9857377	Flex Amber	FLEX LNG	Hyundai	174000	XDF	2020
9857365	Flex Aurora	FLEX LNG	Hyundai	174000	XDF	2020
9862475	Flex Vigilant	FLEX LNG	Hyundai	174000	XDF	2021

Appendix 4: Table of Global LNG Vessel Orderbook (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cbm)	Propulsion Type	Delivery Year
9862463	Flex Volunter	FLEX LNG	Hyundai	174000	XDF	2021
9845764	La Seine	TMS Cardiff Gas	Hyundai	174000	XDF	2020
9864746	SCF Barents	Sovcomflot	Hyundai	174000	XDF	2020
9849887	Scf La Perouse	Sovcomflot	Hyundai	174000	XDF	2020
9854765	Traiano Knutsen	Knutsen OAS Shipping	Hyundai	180000	MEGI	2020
9837066	Vasant	Triumph Offshore Pvt	Hyundai	180000	DFDE/TFDE	2020
9864667	VIVIT Americas	TMS Cardiff Gas	Hyundai	174000	XDF	2020
9874040	Hyundai Mipo 8232	Knutsen OAS Shipping	Hyundai	30000	XDF	2021
9870525	Hyundai Samho 8008	Sovcomflot	Hyundai	174000	XDF	2021
9862487	Hyundai Samho 8029	N.Y.K. Line	Hyundai	174000	XDF	2020
9874454	Hyundai Samho 8030	N.Y.K. Line	Hyundai	174000	XDF	2021
9874466	Hyundai Samho 8031	N.Y.K. Line	Hyundai	174000	XDF	2021
9872987	Hyundai Samho 8039	Consolidated Marine	Hyundai	173400	XDF	2021
9872999	Hyundai Samho 8040	Consolidated Marine	Hyundai	173400	XDF	2021
9904170	Hyundai Samho 8091	J.P. Morgan	Hyundai	174000	XDF	2022
9904782	Hyundai Samho 8092	J.P. Morgan	Hyundai	174000	XDF	2022
9904194	Hyundai Samho 8093	Korea Line	Hyundai	174000	XDF	2022
9904209	Hyundai Samho 8094	Korea Line	Hyundai	174000	XDF	2022
	Hyundai Samho Newbuild	H-Line Shipping	Hyundai		XDF	2021
9884473	Hyundai Samho S971	N.Y.K. Line	Hyundai		XDF	2021
9888481	Hyundai Ulsan 2939	SK Shipping	Hyundai		XDF	2021
9872901	Hyundai Ulsan 3039	TMS Cardiff Gas	Hyundai	174000	XDF	2021
9859820	Hyundai Ulsan 3095	Turkish Petroleum Corp.	Hyundai	170000	DFDE/TFDE	2020
9892298	Hyundai Ulsan 3111		Hyundai			2020
9872949	Hyundai Ulsan 3112	TMS Cardiff Gas	Hyundai	174000	XDF	2021
9886732	Hyundai Ulsan 3137	Dynagas	Hyundai		XDF	2022
9886744	Hyundai Ulsan 3138	Dynagas	Hyundai		XDF	2022
9892456	Hyundai Ulsan 3157	Tsakos Energy Nav	Hyundai		XDF	2021
9902902	Hyundai Ulsan 3185	Knutsen OAS Shipping	Hyundai	174000	XDF	2022

Appendix 4: Table of Global LNG Vessel Orderbook (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cbm)	Propulsion Type	Delivery Year
9902914	Hyundai Ulsan 3186	Knutsen OAS Shipping	Hyundai	174000	XDF	2022
9902926	Hyundai Ulsan 3187	Knutsen OAS Shipping	Hyundai	174000	XDF	2022
9902938	Hyundai Ulsan 3188	Knutsen OAS Shipping	Hyundai	174000	XDF	2022
9778923	MARVEL SWAN	Kawasaki Kisen	Imabari	178000	MEGI	2021
9789037	Imabari Saijo 8215		Imabari	178000	MEGI	2022
9789049	Imabari Saijo 8216		Imabari	178000	MEGI	2022
9789051	Imabari Saijo 8217		Imabari	178000	MEGI	2022
9864837	Jiangnan Jovo 1	Jovo Group	Jiangnan	79800		2021
9864849	Jiangnan Jovo 2	Jovo Group	Jiangnan	79800		2021
9863182	Dorado LNG	TMS Cardiff Gas	Samsung	174000	XDF	2020
9819650	GASLOG WINDSOR	Gaslog LNG Services	Samsung	180000	XDF	2020
9854935	Samsung 2255	PT Jawa Satu Regas	Samsung	170000	DFDE/TFDE	2020
9855812	Samsung 2262	Gaslog LNG Services	Samsung	174000	XDF	2020
9851787	Samsung 2271	TMS Cardiff Gas	Samsung	174000	XDF	2020
9853137	Samsung 2274	Gaslog LNG Services	Samsung	180000	XDF	2020
9862346	Samsung 2275	TMS Cardiff Gas	Samsung	174000	XDF	2020
9864784	Samsung 2297	Celsius Shipping	Samsung	180000	XDF	2020
9864796	Samsung 2298	Celsius Shipping	Samsung	180000	XDF	2020
9864916	Samsung 2300	Gaslog LNG Services	Samsung	174000	XDF	2020
9864928	Samsung 2301	Gaslog LNG Services	Samsung	174000	XDF	2020
9870159	Samsung 2302	N.Y.K. Line	Samsung	180000	XDF	2021
9869942	Samsung 2304	Minerva Marine	Samsung	174000	XDF	2021
9877341	Samsung 2305	Minerva Marine	Samsung		MEGI	2021
9874480	Samsung 2306	N.Y.K. Line	Samsung	174000	XDF	2021
9874492	Samsung 2307	N.Y.K. Line	Samsung	174000	XDF	2021
9875800	Samsung 2308	TMS Cardiff Gas	Samsung	174000	MEGI	2021
9876660	Samsung 2311	Gaslog LNG Services	Samsung	174000	XDF	2021

Appendix 4: Table of Global LNG Vessel Orderbook (continued)

IMO Number	Vessel Name	Shipowner	Shipbuilder	Capacity (cbm)	Propulsion Type	Delivery Year
9876737	Samsung 2312	Gaslog LNG Services	Samsung	174000	XDF	2021
9878711	Samsung 2313	Celsius Shipping	Samsung		XDF	2021
9878723	Samsung 2314	Celsius Shipping	Samsung		XDF	2021
	Samsung 2315		Samsung		XDF	2021
	Samsung 2316		Samsung		XDF	2021
	Samsung 2317		Samsung		XDF	2022
	Samsung 2318		Samsung		XDF	2022
9888766	Samsung 2319	Nisshin Shipping	Samsung		XDF	2022
	Samsung 2336		Samsung		XDF	2022
	Samsung 2337		Samsung		XDF	2022
9893606	Samsung 2355	N.Y.K. Line	Samsung		XDF	2021
9896440	Samsung 2364	MISC	Samsung			2023
9896452	Samsung 2365	MISC	Samsung			2023
9693719	Coral Encanto	Anthony Veder	Zhejiang	30000		2020
	Zvezda Shipbuilding newbuild	Sovcomflot	Zvezda Shipbuilding		TFDE	2023

Source : Rystad Energy

Appendix 5: Table of Global LNG Receiving Terminals[4]

Existing as of February 2020						
Reference Number	Market	Terminal Name or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners	Concept
1	Spain	Barcelona LNG	1969	12.5	Enagas (100%);	Onshore
2	Japan	Negishi	1969	12	JERA (50%); Tokyo Gas (50%);	Onshore
3	United States	Everett	1971	5.4	Exelon Generation (100%)	Onshore
4	Italy	Panigaglia LNG	1971	2.5	GNL Italia (100%);	Onshore
5	France	Fos Tonkin	1972	2.2	ENGIE (100%)	Onshore
6	Japan	Senboku	1972	15.3	Osaka Gas (100%);	Onshore
7	Japan	Sodegaura	1973	29.4	JERA (50%); Tokyo Gas (50%);	Onshore
8	Japan	Chita LNG Joint Terminal / Kyodo	1977	7.5	JERA (50%); Toho Gas (50%);	Onshore
9	Japan	Tobata	1977	6.8	Kitakyushu LNG (100%);	Onshore
10	United States	Elba Island LNG	1978	12	Kinder Morgan (100%);	Onshore
11	Japan	Himeji	1979	14	Osaka Gas (100%);	Onshore
12	France	Montoir-de-Bretagne	1980	7.3	ENGIE (100%);	Onshore
13	Japan	Chita LNG	1983	10.9	JERA (50%); Toho Gas (50%);	Onshore
14	Japan	Higashi-Ohgishima	1984	14.7	JERA (100%);	Onshore
15	Japan	Higashi-Niigata	1984	8.9	Nihonkai LNG (58.1%); Tohuko Electric (41.9%);	Onshore
16	Japan	Futtsu LNG	1985	16	JERA (100%);	Onshore
17	South Korea	Pyeongtaek LNG	1986	40.6	KOGAS (100%);	Onshore
18	Belgium	Zeebrugge	1987	6.6	Fluxys LNG SA (100%)	Onshore
19	Japan	Yokkaichi LNG Center	1987	7.1	JERA (100%);	Onshore
20	Spain	Huelva	1988	8.6	Enagas (100%);	Onshore
21	Spain	Cartagena	1989	8.6	Enagas (100%);	Onshore
22	Japan	Oita LNG	1990	5.1	Kyushu Electric (100%);	Onshore
23	Chinese Taipei	Yung-An	1990	9.5	CPC (100%);	Onshore
24	Japan	Yanai	1990	2.4	Chugoku Electric (100%);	Onshore
25	Japan	Yokkaichi Works	1991	2.1	Toho Gas (100%);	Onshore
26	Turkey	Marmara Ereglisi	1994	5.9	Botas (100%);	Onshore
27	South Korea	Incheon	1996	41.7	KOGAS (100%);	Onshore
28	Japan	Hatsukaichi	1996	0.9	Hiroshima Gas (100%);	Onshore
29	Japan	Sodeshi	1996	1.6	Shizuoka Gas (65%); TonenGeneral (35%);	Onshore
30	Japan	Kawagoe	1997	7.7	JERA (100%);	Onshore
31	Japan	Shin-Minato	1997	0.3	Sendai Gas (0%); Gas Bureau (100%);	Onshore
32	Japan	Ohgishima	1998	9.9	Tokyo Gas (100%);	Onshore
33	Greece	Revithoussa	2000	4.6	DEPA (100%)	Onshore
34	United States	EcoElectrica	2000	1.2	Naturgy (47.5%); ENGIE (35%); Mitsui (15%); GE Capital (2.5%)	Onshore
35	Japan	Chita Midorihama Works	2001	8.3	Toho Gas (100%);	Onshore
36	South Korea	Tongyeong LNG	2002	26.6	KOGAS (100%);	Onshore
37	United States	Cove Point LNG	2003	11	Dominion Cove Point LNG (100%);	Onshore

Appendix 5: Table of Global LNG Receiving Terminals (continued)

Existing as of February 2020						
Reference Number	Market	Terminal Name or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners	Concept
38	Dominican Republic	AES Andres LNG	2003	1.9	AES (92%); Estrella-Linda (8%);	Onshore
39	Spain	Bahía de Bizkaia Gas	2003	5.1	ENAGAS (50%); EVE (50%);	Onshore
40	Portugal	Sines LNG Terminal	2004	5.8	REN (100%);	Onshore
41	India	Dahej LNG	2004	17.5	Petronet LNG (100%);	Onshore
42	South Korea	Gwangyang	2005	2.3	POSCO (100%);	Onshore
43	India	Hazira LNG	2005	5	Shell (100%)	Onshore
44	United Kingdom	Grain LNG	2005	15	National Grid Transco (100%);	Onshore
45	Japan	Sakai LNG	2006	6.4	Kansai Electric (70%); Cosmo Oil (12.5%); Iwatani (12.5%); Ube Industries (5%);	Onshore
46	Japan	Mizushima	2006	4.3	Chugoku Electric (50%); JX Nippon Oil & Energy (50%);	Onshore
47	Spain	Sagunto	2006	6.4	ENAGAS (72.5%); Osaka Gas (20%); Oman Oil (7.5%);	Onshore
48	Turkey	Aliaga Izmir LNG	2006	4.4	EgeGaz (100%);	Onshore
49	Mexico	Terminal de LNG Altamira	2006	5.4	Vopak (60%); ENAGAS (40%);	Onshore
50	China	Guangdong Dapeng LNG	2006	6.8	Local Company (37%); CNOOC (33%); BP (30%)	Onshore
51	Spain	Mugardos LNG	2007	2.6	Grupo Tojeiro (50.36%); Gobierno de Galicia (24.64%); First State Regasificadora (15%); Sonatrach (10%);	Onshore
52	Mexico	Energia Costa Azul	2008	7.6	Sempra Energy (100%);	Onshore
53	United States	Freeport LNG	2008	11.3	Michael S Smith Cos (57.5%); Global Infrastructure Partners (25%); Osaka Gas (10%); Dow Chemical (7.5%);	Onshore
54	China	Wuhaogou LNG	2008	1	Shenergy (100%)	Onshore
55	United States	Northeast Gateway	2008	4.5	Excelerate Energy (100%);	Floating
56	Canada	Canaport LNG	2009	7.5	Repsol (75%); Irving Oil (25%);	Onshore
57	United Kingdom	South Hook	2009	15.6	Qatar Petroleum (67.5%); Exxon Mobil (24.25%); TOTAL (8.35%);	Onshore
58	Chinese Taipei	Taichung LNG	2009	4.5	CPC (100%);	Onshore
59	Italy	Adriatic LNG	2009	5.8	Exxon Mobil (46.35%); Qatar Petroleum (46.35%); Edison (7.3%);	Offshore
60	Chile	GNL Quintero	2009	4	ENAGAS (60.4%); ENAP (20%); Oman Oil (19.6%);	Onshore
61	United Kingdom	Dragon LNG	2009	7.5	Shell (50%); Ancala (50%)	Onshore
62	China	Shanghai LNG	2009	3	Shenergy Group (55%); CNOOC (45%);	Onshore
63	China	Fujian LNG	2009	5.2	CNOOC (60%); Fujian Investment and Development Co (40%);	Onshore

[4] Only floating terminals with active FSRU charter(s) or have chartered FSRU vessel(s) installed at site are included in the table.

Appendix 5: Table of Global LNG Receiving Terminals (continued)

Existing as of February 2020						
Reference Number	Market	Terminal Name or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners	Concept
64	Japan	Sakaide LNG	2010	1.2	Shikoku Electric Power Co. (70%); Cosmo Oil Co. Ltd (20%); Shikoku Gas Co. (10%);	Onshore
65	France	Fos Cavaou	2010	6	ENGIE (71.5%); TOTAL (28.5%);	Onshore
66	China	Jiangsu Rudong LNG	2011	6.5	CNPC (55%); Pacific Oil and Gas (35%); Jiangsu Guoxin (10%);	Onshore
67	Argentina	GNL Escobar - Excelerate Exemplar	2011	3.8	YPF (50%); Enarsa (50%);	Floating
68	China	Dalian LNG	2011	6	CNPC (75%); Dalian Port (20%); Dalian Construction Investment Corporation (5%);	Onshore
69	Netherlands	Gate LNG	2011	9	Gasuine (50%); Vopak (50%);	Onshore
70	Thailand	Map Ta Phut	2011	11.5	PTT LNG (100%);	Onshore
71	Mexico	Terminal KMS	2012	3.8	Samsung (37.5%); Mitsui (37.5%); KOGAS (25%);	Onshore
72	Indonesia	Nusantara Regas Satu - FSRU Jawa Barat	2012	3.8	Pertamina (60%); PGN (40%);	Floating
73	Japan	Joetsu	2012	2.3	JERA (100%);	Onshore
74	China	Zhejiang Ningbo LNG	2012	3	CNOOC (51%); Zhejiang Energy Company (29%); Ningbo Power (20%)	Onshore
75	Japan	Ishikari LNG	2012	2.7	Hokkaido Gas (100%);	Onshore
76	Singapore	Jurong	2013	11	EMA (100%)	Onshore
77	China	Zhuhai LNG	2013	3.5	CNOOC (30%); Guangdong Gas (25%); Guangdong Yuedian (25%); Local companies (20%);	Onshore
78	Malaysia	Melaka LNG	2013	3.8	Petronas (100%);	Floating
79	China	Jovo Dongguan	2013	1.5	Jovo Group (100%);	Onshore
80	Israel	Hadera Deepwater LNG - Excelerate Expedient	2013	3	INGL (100%);	Floating
81	China	Caofeidian (Tangshan) LNG	2013	6.5	CNPC (51%); Beijing Enterprises Group Company (29%); Hebei Natural Gas (20%);	Onshore
82	Japan	Naoetsu LNG	2013	1.5	INPEX (100%);	Onshore
83	India	Kochi LNG	2013	5	Petronet LNG (100%);	Onshore
84	India	Dabhol LNG	2013	2	Gail (31.52%); NTPC (31.52%); Indian Financial Institutions (20.28%); MSEB Holding Co. (16.68%);	Onshore
85	Italy	Toscana - Toscana FSRU	2013	2.7	IREN Group (49.07%); First State Investments (48.24%); Golar LNG (2.69%)	Floating
86	China	Shandong (Qingdao) LNG	2014	3	Sinopec (99%); Qingdao Port(1%);	Onshore
87	Lithuania	Klaipeda LNG - Hoegh Independence	2014	3	Klaipedos Nafta (100%);	Floating
88	Brazil	Bahia LNG - Golar Winter	2014	3.8	Petrobras (100%);	Floating
89	Chile	GNL Mejillones 2 (onshore storage)	2014	1.5	ENGIE (63%); Ameris Capital AGF(37%);	Onshore
90	Kuwait	Mina Al Ahmadi - Golar Igloo	2014	5.8	Golar LNG (0%); Kuwait Petroleum Corporation (100%);	Floating
91	Japan	Hibiki LNG	2014	2.4	Saibu Gas (90%); Kyushu Electric (10%);	Onshore
92	Indonesia	Lampung LNG - PGN FSRU Lampung	2014	1.8	Terminal: PGN (100%), FSRU: Hoegh LNG (100%)	Floating
93	South Korea	Samcheok LNG	2014	11.6	KOGAS (100%);	Onshore
94	China	Hainan LNG	2014	4.32	CNOOC (65%); Hainan Developing Holding (35%);	Onshore
95	Japan	Shin-Sendai	2015	1.5	Tohoku Electric (100%);	Onshore
96	Pakistan	Port Qasim Karachi - Excelerate Exquisite	2015	3.8	Terminal: Elengy Terminal Pakistan Ltd. (100%), FSRU: Excelerate Energy (100%)	Floating
97	Jordan	Jordan LNG - Golar Eskimo	2015	3.8	Golar LNG (0%); Jordan MEMR (100%);	Floating
98	Indonesia	Arun LNG	2015	3	Pertamina (70%); Aceh Regional Government (30%);	Onshore
99	Japan	Hachinohe	2015	1.5	JX Nippon Oil & Energy (100%);	Onshore
100	UAE	Dubai Jebel Ali - Execelerate Explorer	2015	6	Terminal: DUSUP (100%), FSRU: Excelerate Energy (100%)	Floating
101	Japan	Kushiro LNG	2015	0.5	Nippon Oil (100%);	Onshore
102	Poland	Swinoujscie	2016	3.6	Gaz-System (100%);	Onshore
103	China	Guangxi LNG	2016	3	Sinopec (100%);	Onshore
104	Colombia	Cartagena (Colombia) - Hoegh Grace	2016	3	Hoegh LNG (0%); Promigas (51%); Baru LNG (49%);	Floating
105	Brazil	Pecem LNG - Excelerate Experience	2016	5.4	Petrobras (100%);	Floating
106	Japan	Hitachi LNG	2016	3.8	Tokyo Gas (100%);	Onshore
107	China	Qidong LNG	2017	1.2	Xinjiang Guanghui Petroleum (100%)	Onshore
108	South Korea	Boryeong LNG	2017	3	GS Caltex (50%); SK E&S (50%);	Onshore
109	France	Dunkirk LNG	2017	9.5	EDF (65%); Fluxys (25%); TOTAL (10%);	Onshore
110	Egypt	Sumed - BW Singapore	2017	5.7	Terminal: EGAS (100%), FSRU: BW (100%)	Floating
111	Pakistan	Port Qasim GasPort - BW Integrity	2017	5.7	Terminal: Pakistan LNG Terminals Limited (100%), FSRU: BW (100%)	Floating
112	Malaysia	Pengerang LNG	2017	3.5	PETRONAS (65%); Dialog Group (25%); Johor Government (10%);	Onshore
113	China	Jieyang LNG (Yuedong)	2017	2	CNOOC (100%);	Onshore
114	China	Tianjin (CNOOC)	2018	3.5	CNOOC (100%);	Onshore
115	Japan	Soma LNG	2018	1.5	JAPEX (100%);	Onshore

Appendix 5: Table of Global LNG Receiving Terminals (continued)

Existing as of February 2020						
Reference Number	Market	Terminal Name or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners	Concept
116	Bangladesh	Moheshkhali - Excelerate Excellence	2018	3.75	Terminal: PetroBangla (100%), FSRU: Excelerate Energy (100%)	Floating
117	China	Diefu LNG (Shenzhen)	2018	4	CNOOC (70%); Shenzhen Energy Group (30%);	Onshore
118	China	Tianjin FSRU - Hoegh Esperanza	2018	6	Terminal: CNOOC (100%), FSRU: Hoegh LNG (100%)	Floating
119	Turkey	Dortyol - MOL FSRU Challenger	2018	5.4	Botas (100%);	Floating
120	China	Tianjin (Sinopec)	2018	3	Sinopec (100%);	Onshore
121	Panama	Costa Norte LNG	2018	1.5	AES Panama (50.1%); Inversiones Bahia (49.9%);	Onshore
122	China	Zhoushan ENN LNG	2018	3	ENN (100%);	Onshore
123	Turkey	Etki LNG terminal - Turquoise	2019	5.7	Terminal: Etki Liman (100%), FSRU: Kolin Construction (100%)	Floating
124	China	Shenzhen Gas LNG	2019	0.8	Shenzhen Gas (100%);	Onshore
125	Bangladesh	Moheshkhali - Excelerate Excelerate	2019	3.8	Terminal: Summit Corp (75%); Mitsubishi (25%), FSRU: Excelerate Energy (100%)	Floating
126	India	Ennore LNG	2019	5	Indian Oil Corporation (95%); Tamil Nadu Industrial Development Corporation (5%);	Onshore
127	Brazil	Sergipe - Golar Nanook FSRU	2019	3.6	Elbrasil (50%); Golar Power (50%);	Floating
128	China	Fangchenggang LNG	2019	0.6	CNOOC (100%);	Onshore
129	Jamaica	Old Harbour - Golar Freeze	2019	3.6	New Fortress Energy (100%);	Floating
130	India	Mundra LNG	2020	5	GSCP (50%); Adani Group (50%);	Onshore

Appendix 6: Table of LNG Receiving Terminals Under Construction

Under Construction as of February 2020						
Reference Number	Market	Terminal Name or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners	Concept
1	India	Jafrabad FSRU	2020	5	Exmar (38%); Gujarat Government (26%); Swan Energy (26%); Tata Group (10%);	Floating
2	Russia	Kaliningrad FSRU	2020	2.7	Gazprom (100%);	Floating
3	Bahrain	Bahrain LNG	2020	6	Bahrain LNG WLL (0%); NOGA (30%); Teekay Corporation (30%); Gulf Investment Corporation (20%); Samsung (20%);	Floating
4	India	H-Gas LNG Gateway (Jaigarh) - Hoegh Cape Ann	2020	4	H-Energy Gateway Private limited (100%);	Floating
5	Brazil	Acu Port LNG	2020	5.6	Prumo Logistica (46.9%); Siemens (33%); BP (20.1%)	Floating
6	Ghana	Ghana - FRU	2020	2	GNPC (50%); Helios (50%)	Floating
7	China	Chaozhou Huafeng LNG	2020	1	Sinoenergy (55%); Chaozhou Huafeng Group (45%);	Onshore
8	United States	San Juan - New Fortress LNG	2020	0.5	New Fortress Energy (100%)	Floating
9	Mexico	New Fortress LNG	2020	3	New Fortress Energy (100%);	Onshore
10	Turkey	Gulf of Saros FSRU	2020	5.4	Botas (100%);	Floating
11	Philippines	Pagbilao LNG	2020	3	Energy World Corporation (100%);	Onshore
12	Croatia	Krk - Golar FSRU	2021	1.9	Terminal: HEP (85%); Plinacro (15%), FSRU: Golar (100%)	Floating
13	Kuwait	Kuwait Permanent LNG Import Facility	2021	22	Kuwait Petroleum Corporation (100%);	Onshore
14	China	Wenzhou LNG	2021	3	Sinopec (41%); Zhejiang Group (51%); Local firms (8%);	Onshore
15	India	Dhamra LNG	2021	5	Adani Group (50%); Total (50%)	Onshore
16	El Salvador	El Salvador FSRU	2021	0.5	Energía del Pacífico (100%);	Floating
17	Indonesia	Cilamaya - Jawa 1 FSRU	2021	2.4	Pertamina (26%); Humpuss (25%); Marubeni (20%); MOL (19%); Sojitz (10%)	Floating
18	China	Binhai LNG	2021	3	CNOOC (100%);	Onshore
19	Cyprus	Cyprus FSRU	2021	0.6	DEFA (100%);	Floating
20	Thailand	Nong Fab LNG	2022	7.5	PTT LNG (100%);	Onshore
21	Japan	Niihama LNG	2022	0.5	Tokyo Gas (50.1%); Shikoku Electric Power (30.1%); Other Japanese Partneers (19.8%);	Onshore
22	India	Chhara LNG	2022	5	HPCL (0%); Shapoorji (100%);	Onshore
23	Vietnam	Thi Vai LNG	2022	1	PetroVietnam Gas (100%);	Onshore
24	China	Zhangzhou LNG	2022	3	CNOOC (60%); Fujian Investment and Development Co (40%);	Onshore
25	China	Yueyang LNG	2022	2	Guanghui Energy (50%); China Huadian (50%);	Onshore
26	China	Yangjiang LNG	2023	2	Guangdong Yudean Power (100%);	Onshore

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