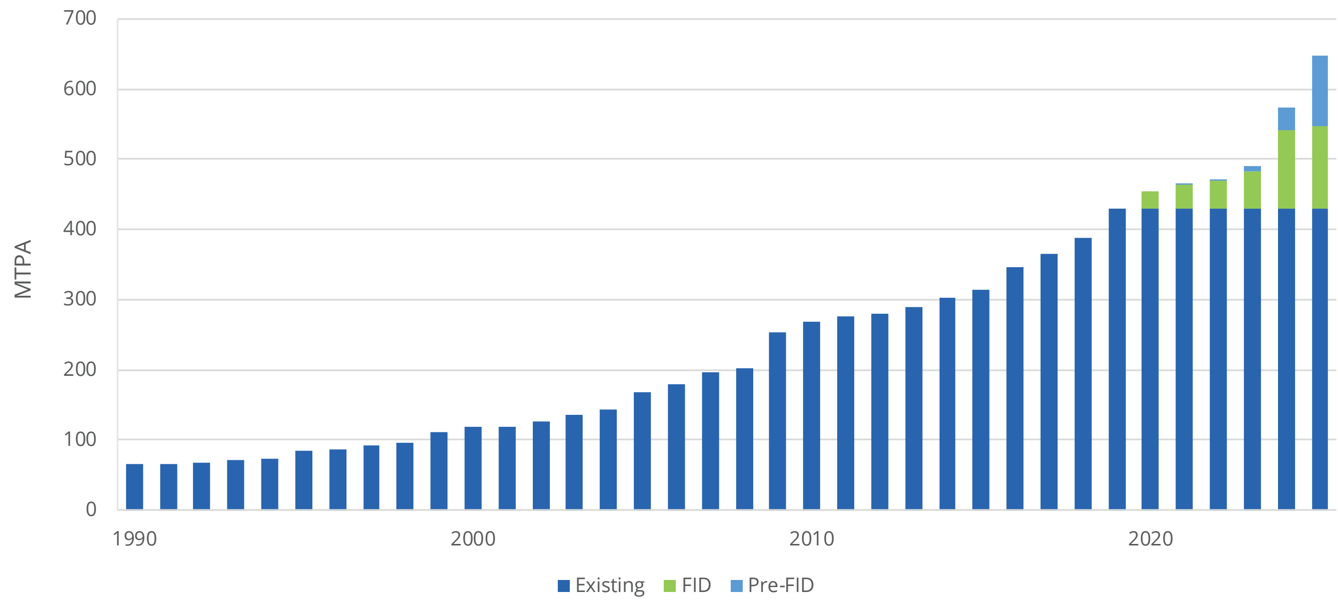
*Figure 4.3: Global Liquefaction Capacity Development from 1990 to 2025*




*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**

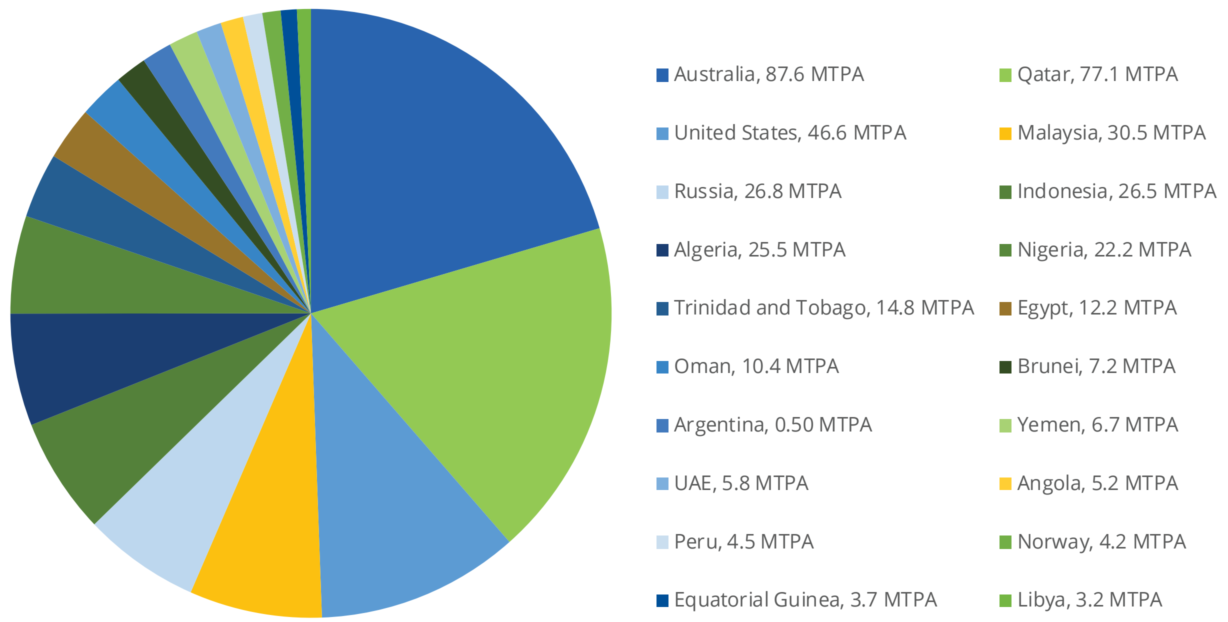
Liquefaction Capacity Under Construction, Dec 2019

### 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.

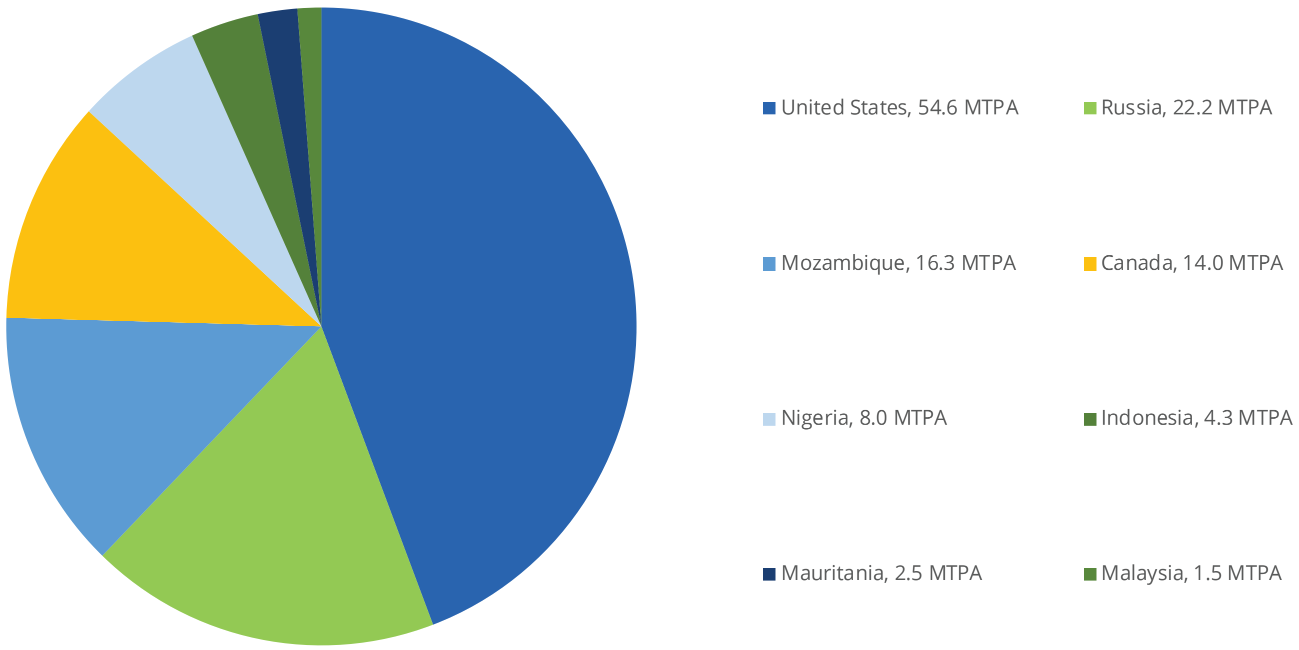
Many projects that commenced construction before 2019 are now undergoing commissioning activities. Elba Island T1-T3 (0.75 MTPA) produced its first commercial cargo at the end of 2019 and commissioning of the remaining trains is ongoing. Cameron LNG T2 (4.0 MTPA) and Freeport LNG T2 (5.1 MTPA) both shipped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

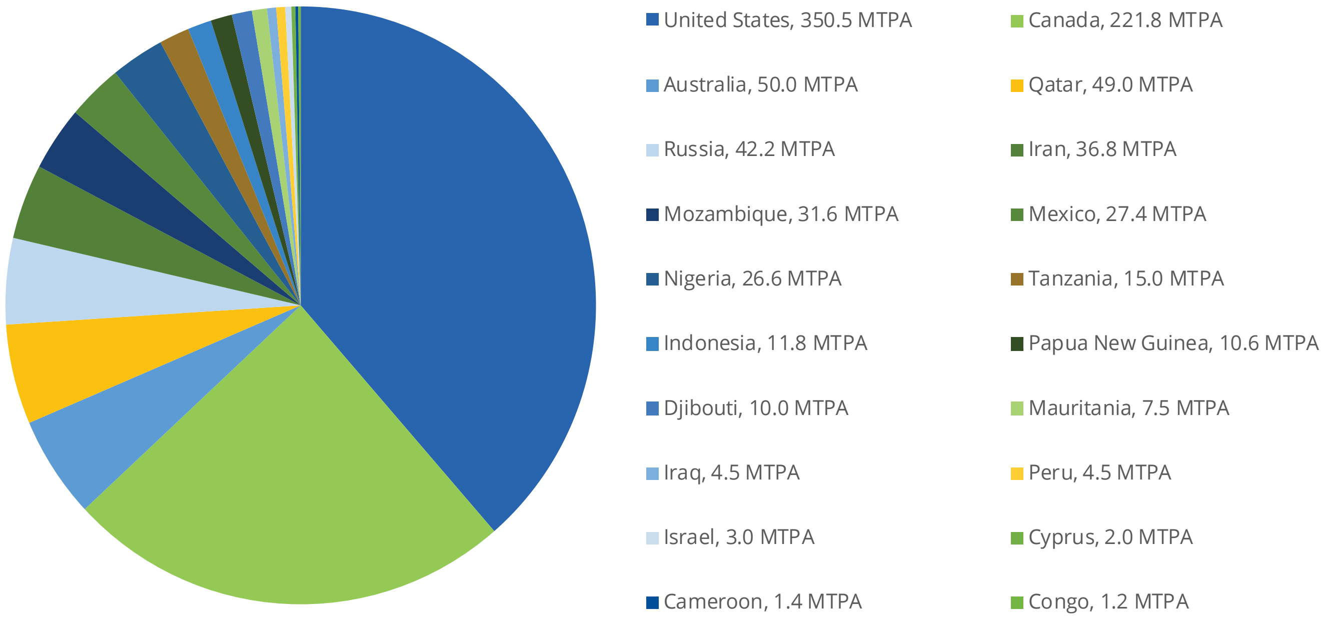



*Source: Rystad Energy*

### 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

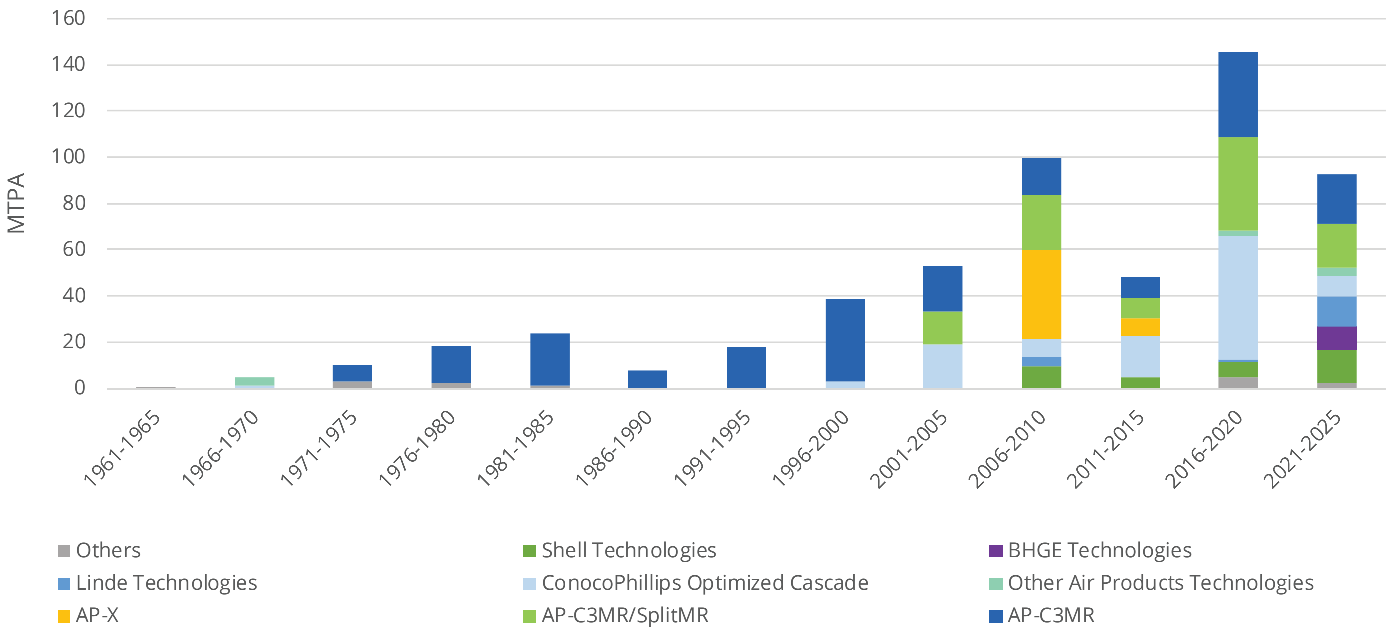
**70% of Global Operational Capacity**

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*



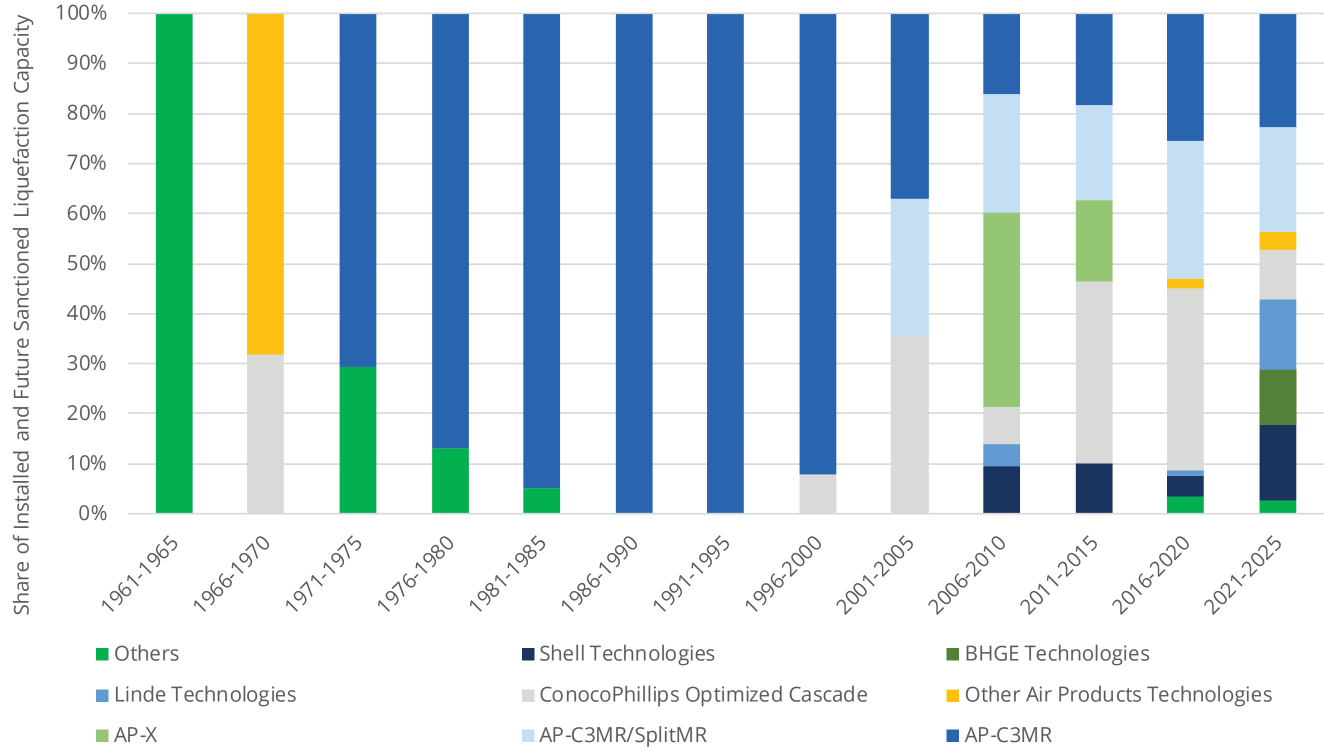

*Source: Rystad Energy*

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)**

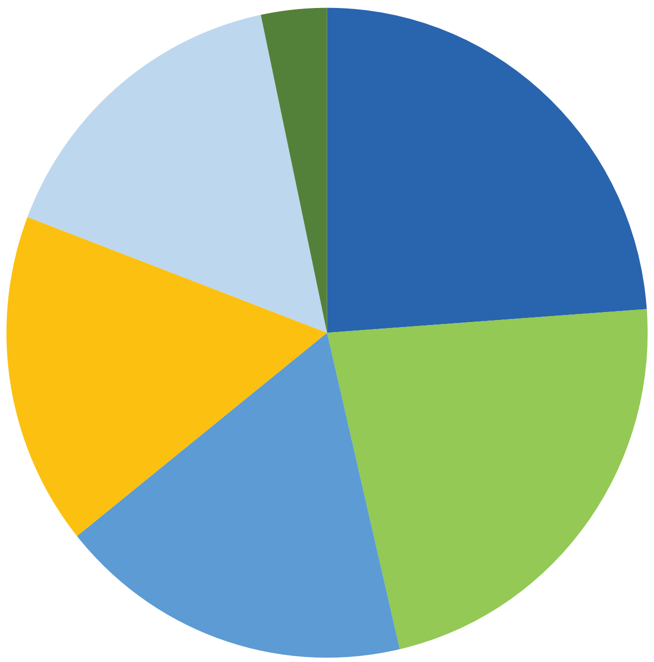
Online in 2019

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.

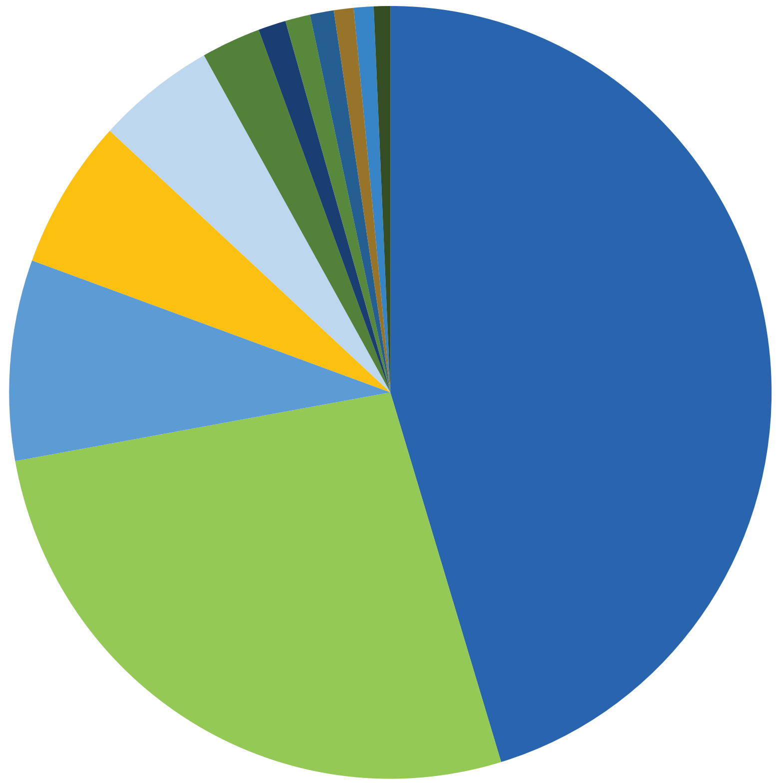
Three FLNGs are currently under construction. Petronas PFLNG Dua (1.5 MTPA) sailed away from the Samsung shipyard in Goeje Island, South Korea in February 2020. It will start to produce LNG from the deepwater Rotan gas field in November 2020. The ENI-led Coral South FLNG (3.4 MTPA), a project of similar 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.

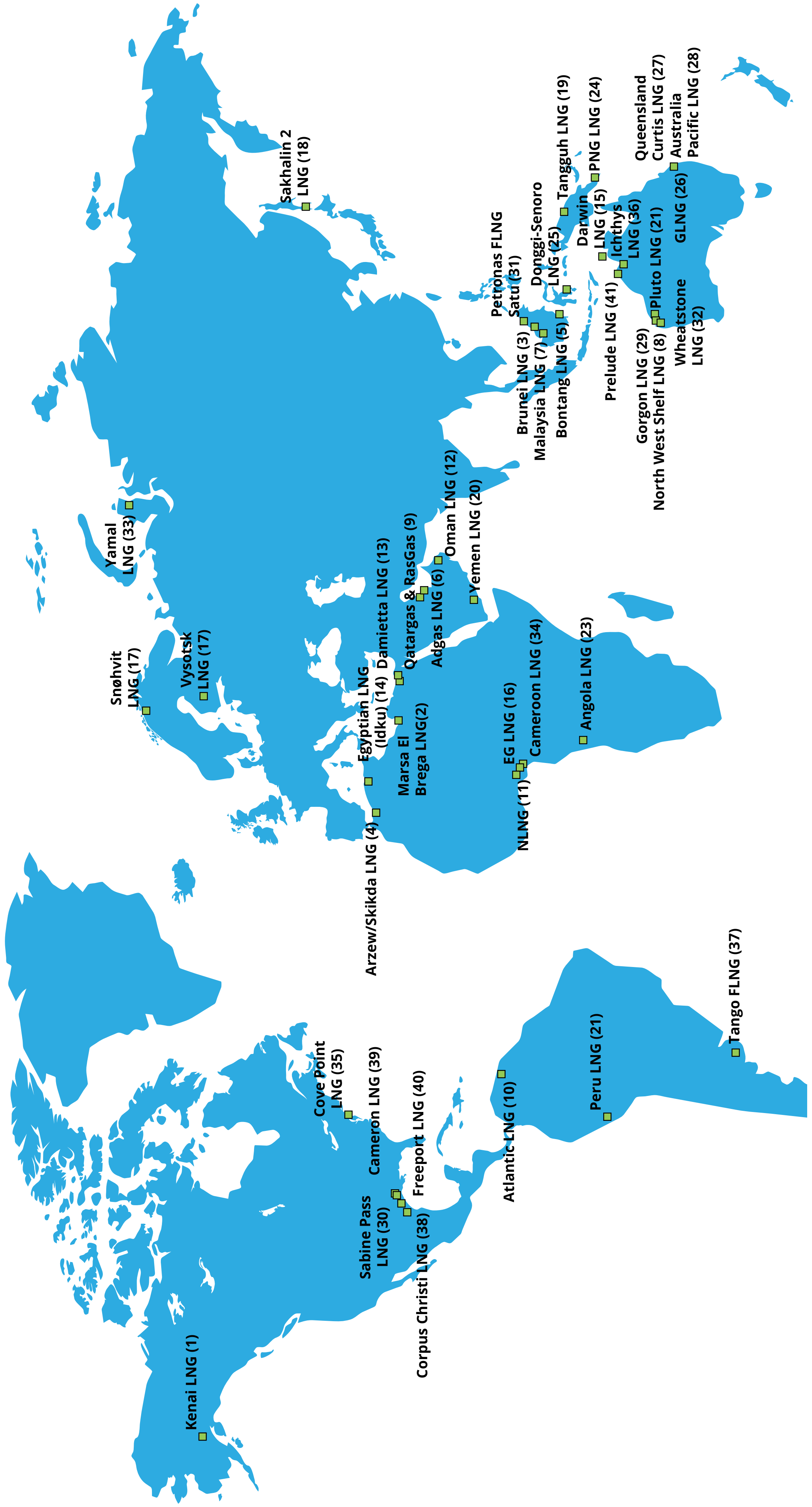



*Figure 4.11: Global Liquefaction Plants, February 2020*

*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 m³ 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.

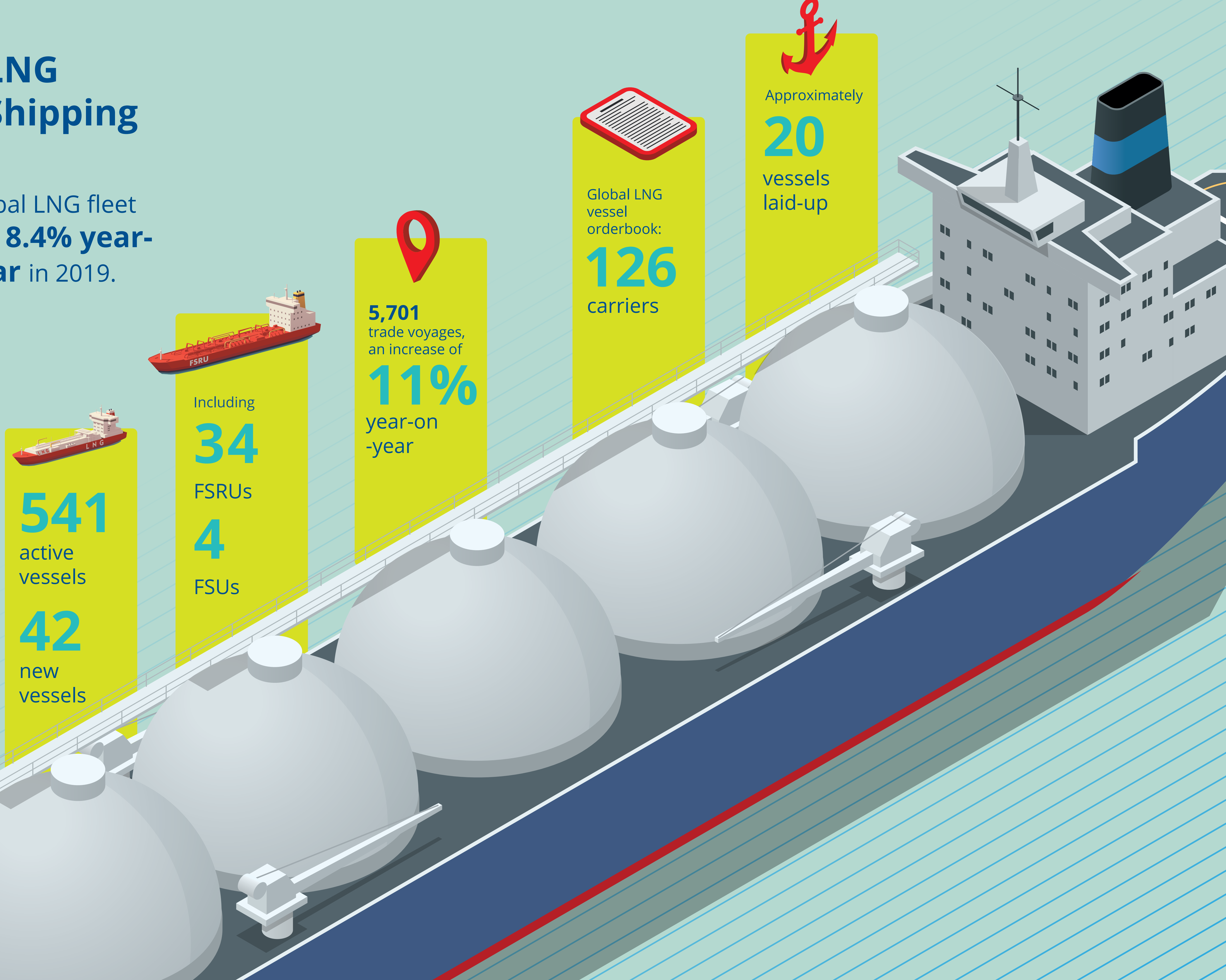
- Petronas' PFLNG1 (1.2 MTPA) LNG-FPSO uses four PGT25+G4 gas turbine generator systems, two PGT25+G4 gas turbine driven compressor units and two electric motor driven centrifugal compressors for two AP-N nitrogen trains. Their PFLNG2 LNG-FPSO (1.5MTPA) uses two LM6000-PF aeroderivative gas turbines 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

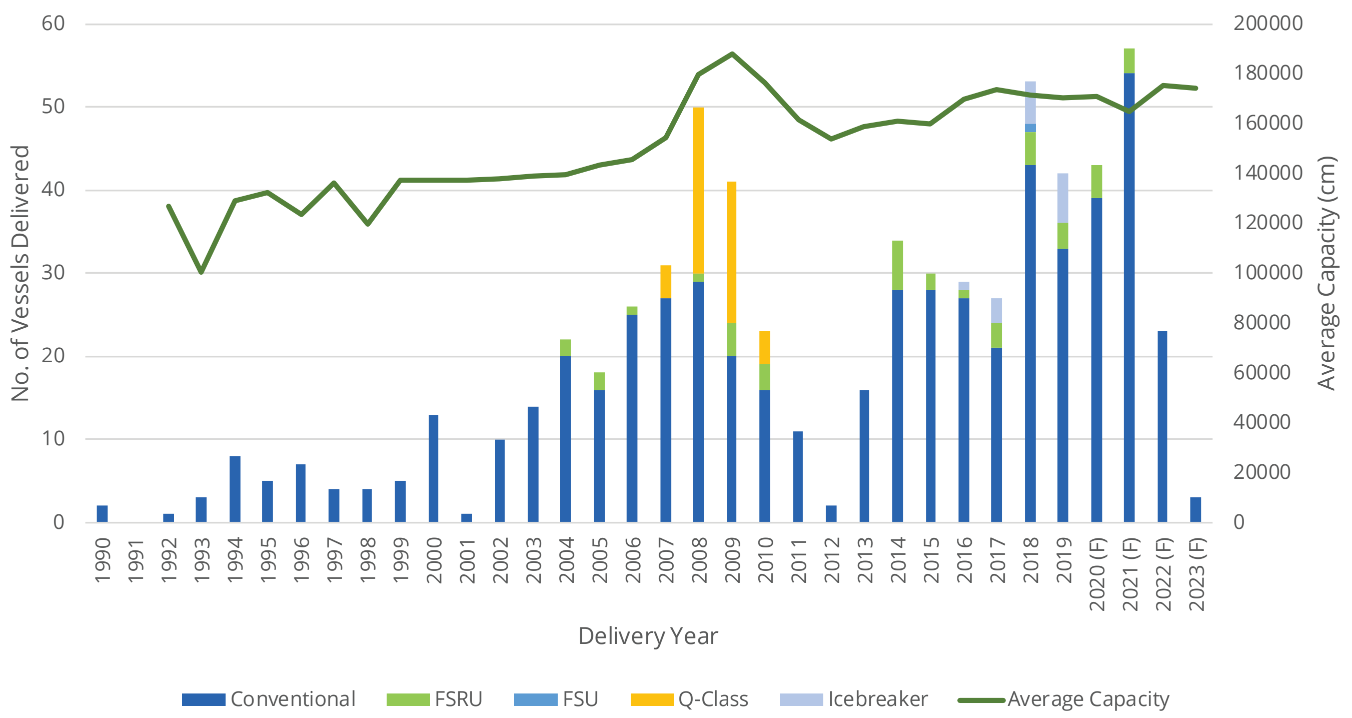
The global LNG fleet[1] at the end of 2019 consisted of 541[2] active vessels, including 34 Floating Storage Regasification Units (FSRUs) and four Floating Storage Units (FSUs). Overall, the global LNG fleet grew by 8.4% year-on-year (YoY) in 2019, with a total addition of 42 new vessels, of which three 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.

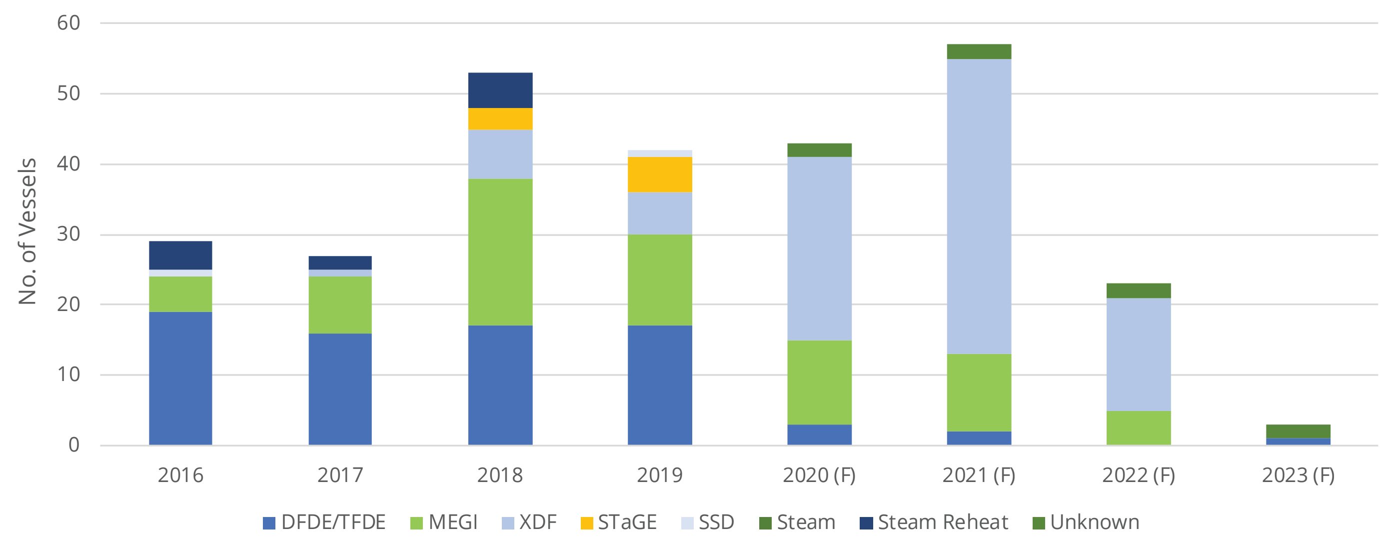
The global LNG vessel orderbook counted 126 carriers as of year-end 2019, an impressive tally representing 23.3% of the current fleet size of 541 units. This illustrates shipowners' expectations that LNG trade will continue to grow, in line with the increase in liquefaction capacities in the coming years. 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<br>Kogas-designed: KC-1 | Moss Maritime-designed: Moss Rosenberg<br>IHI-designed: SPB<br>LNT Marine-designed: LNT A-BOX |
| Advantages | •Space-efficient<br>•Thin and lighter containment system<br>•Higher fuel-efficiency | •More robust in harsh weather conditions<br>•Partial-loading possible<br>•Faster construction |
| Disadvantages | •Partial-loading restricted<br>•Less robust in harsh ocean conditions | •Spherical design uses space inefficiently<br>•Slower cool down rate<br>•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.

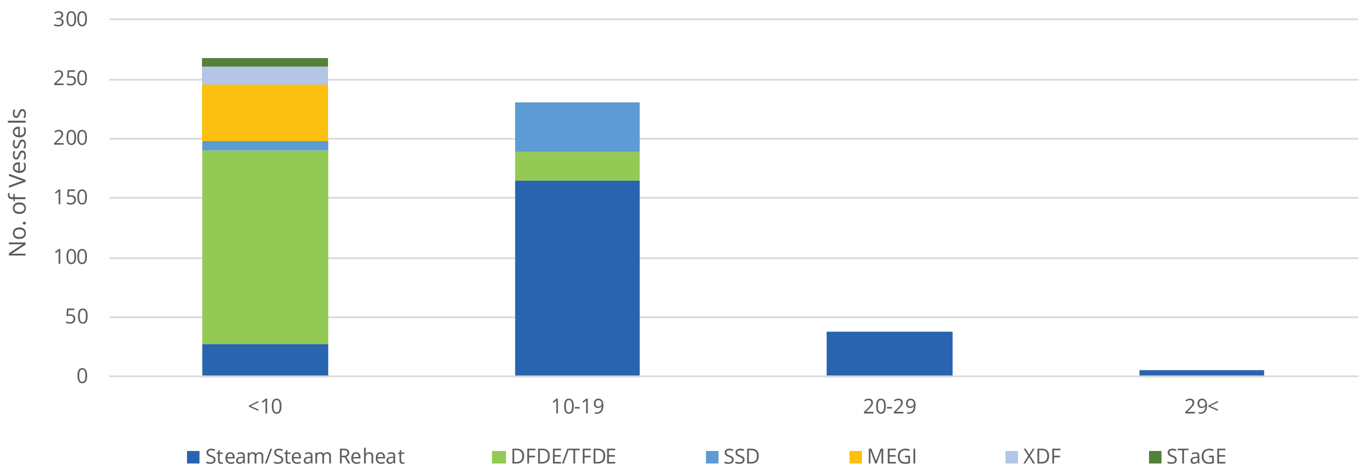
A relatively new system, there are currently 16 vessels with the XDF in service. The orderbook for LNG carriers contains an impressive 84 XDF vessel orders, thus representing the majority of 126 total newbuilds. With safety, efficiency and controlled emissions, the XDF is currently the preferred propulsion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

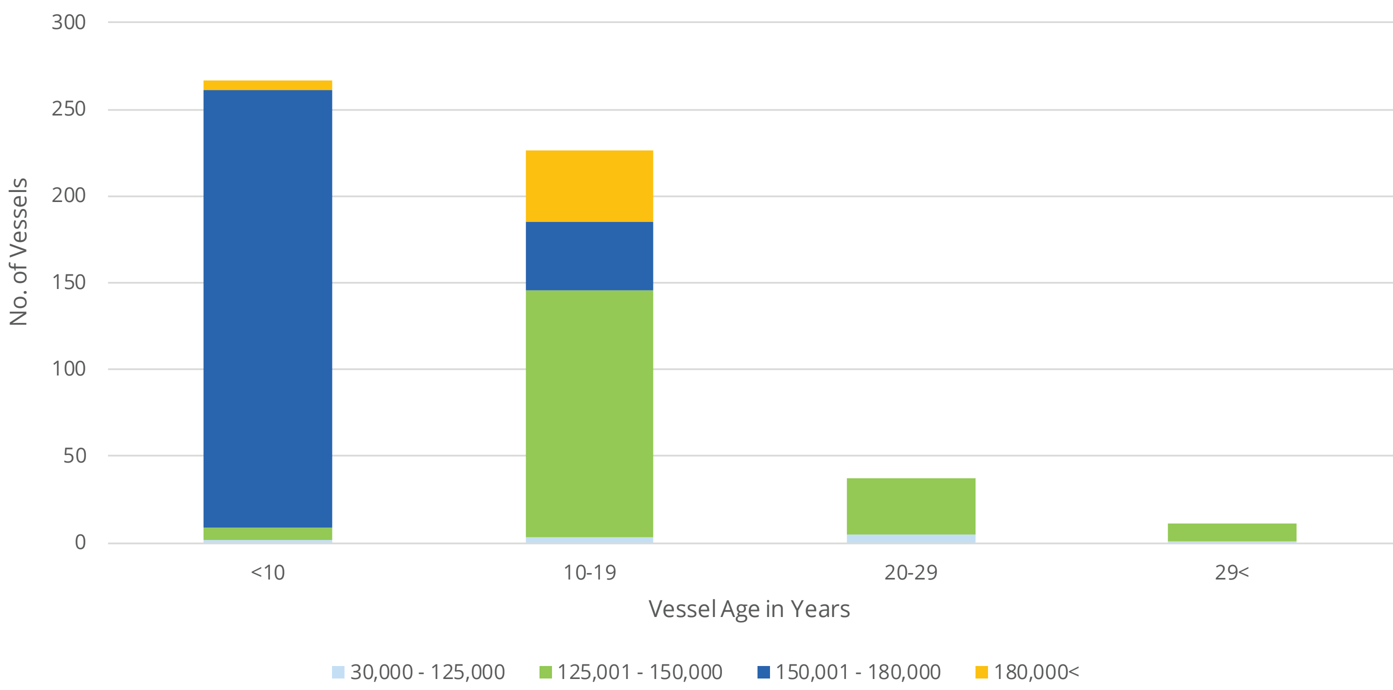
With financial and safety concerns in mind, shipowners plan to operate a vessel for 35-40 years before it is laid-up, a term describing vessels left idle. A decision can then be made on whether to scrap the carrier, convert it to an FSU/FSRU, or return it to operation should market forces pick up.

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*

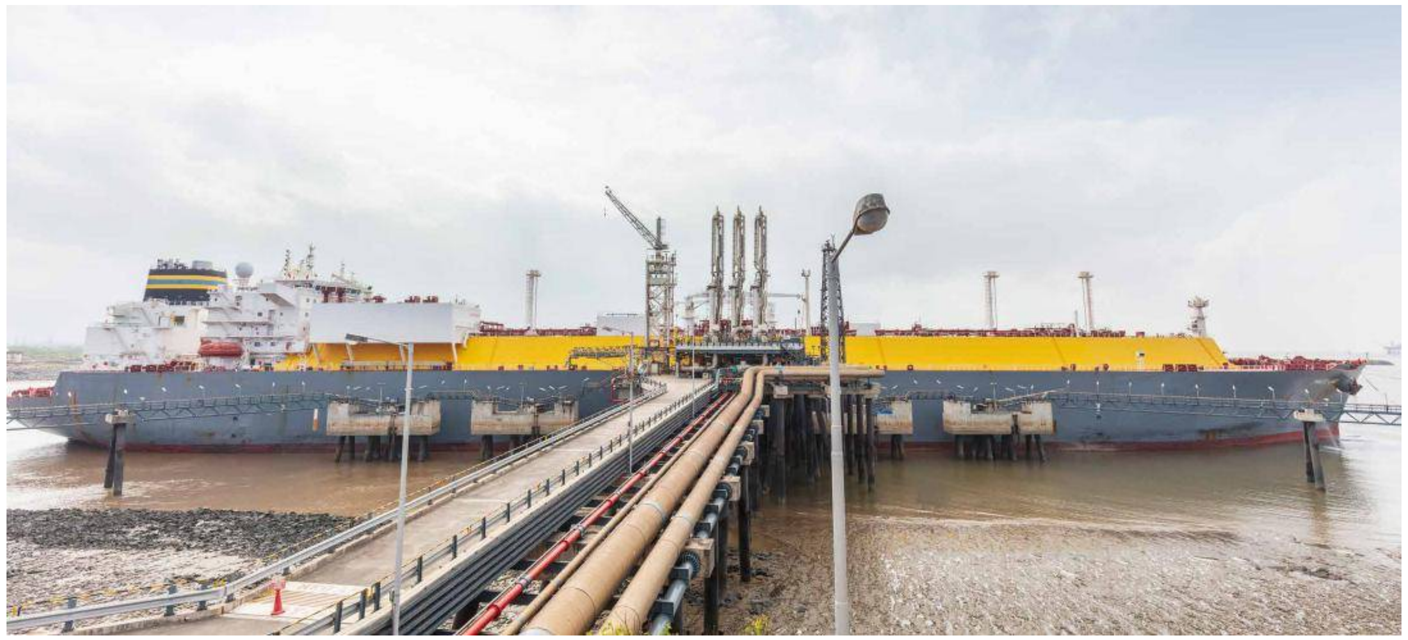



*Source: Rystad Energy*

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.

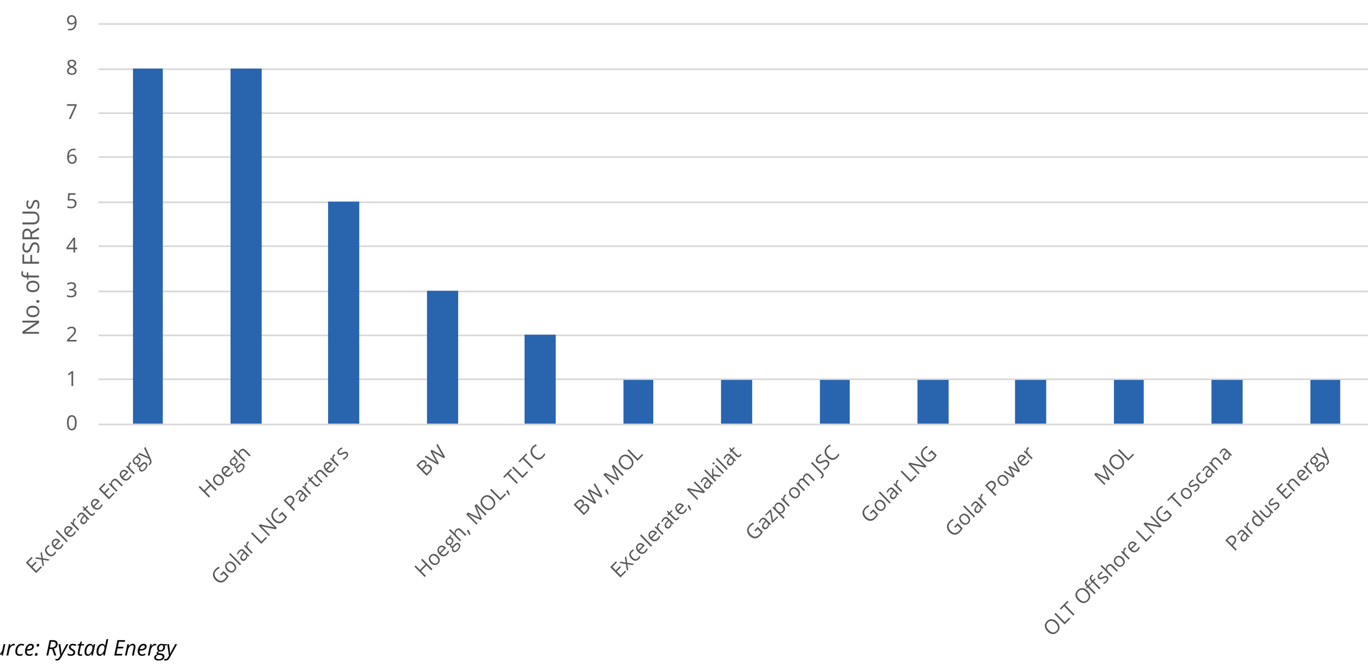
Every vessel delivered in 2019 and 95.5% of the LNG orderbook with determinable capacities fall within the 150,000 to 180,000 cm capacity range.



*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*

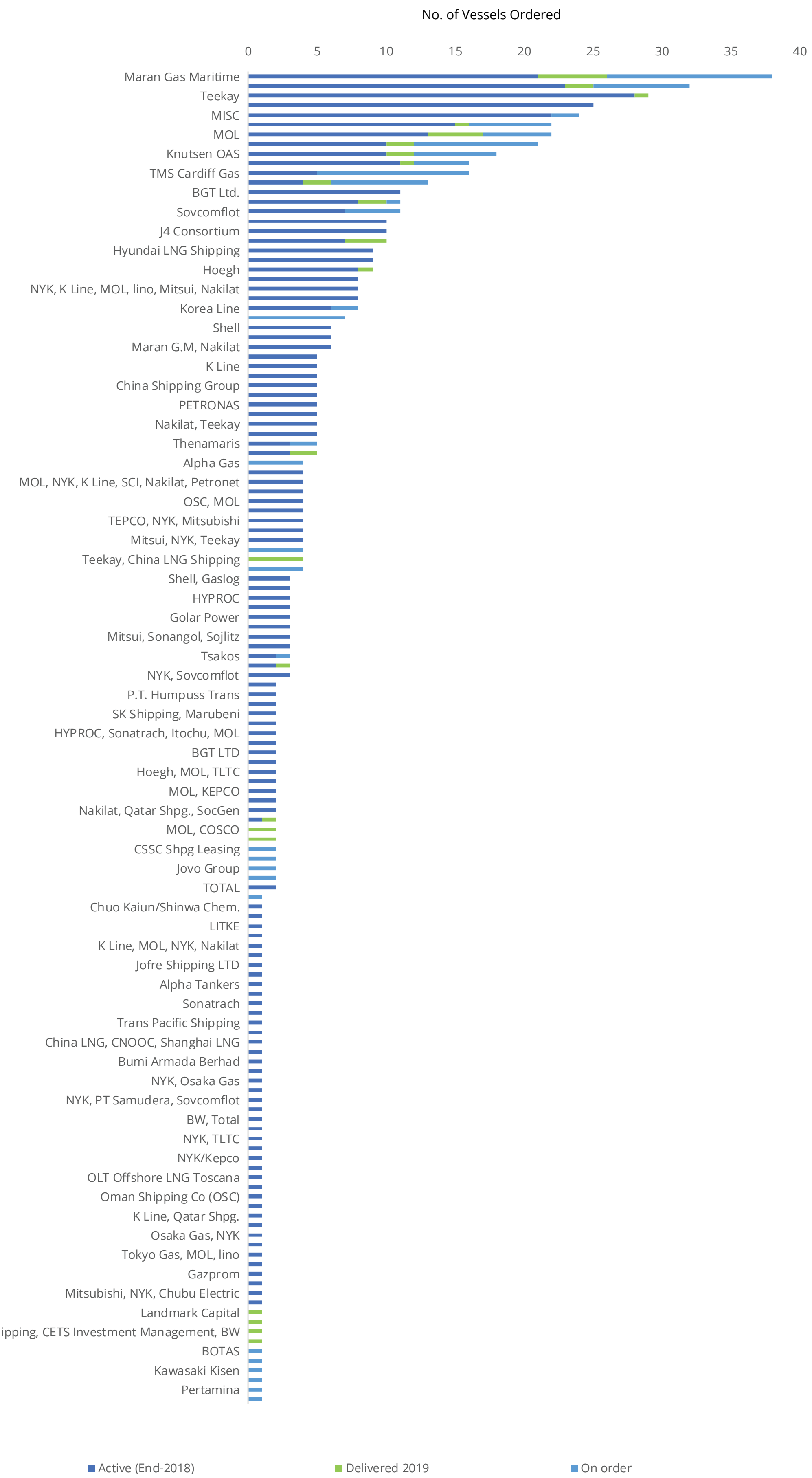
XDF and MEGI propulsion systems will experience strong growth in 2020, capitalising on better fuel efficiencies and lower emissions. Significantly, 84 vessels on order will have XDF propulsion systems in-place. The competing MEGI system has 28 orders, while DFDE/TFDE account for 6 backlog orders, all 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]



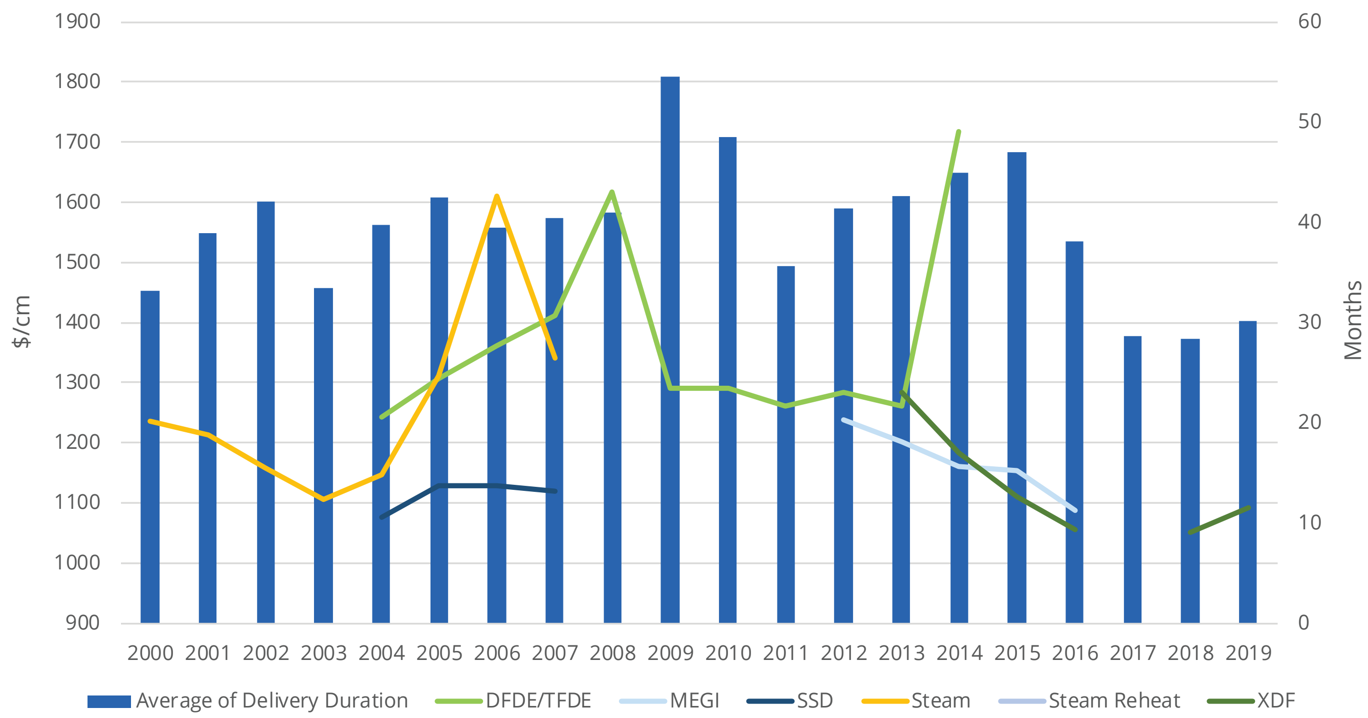

*Source: Rystad Energy*

[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.

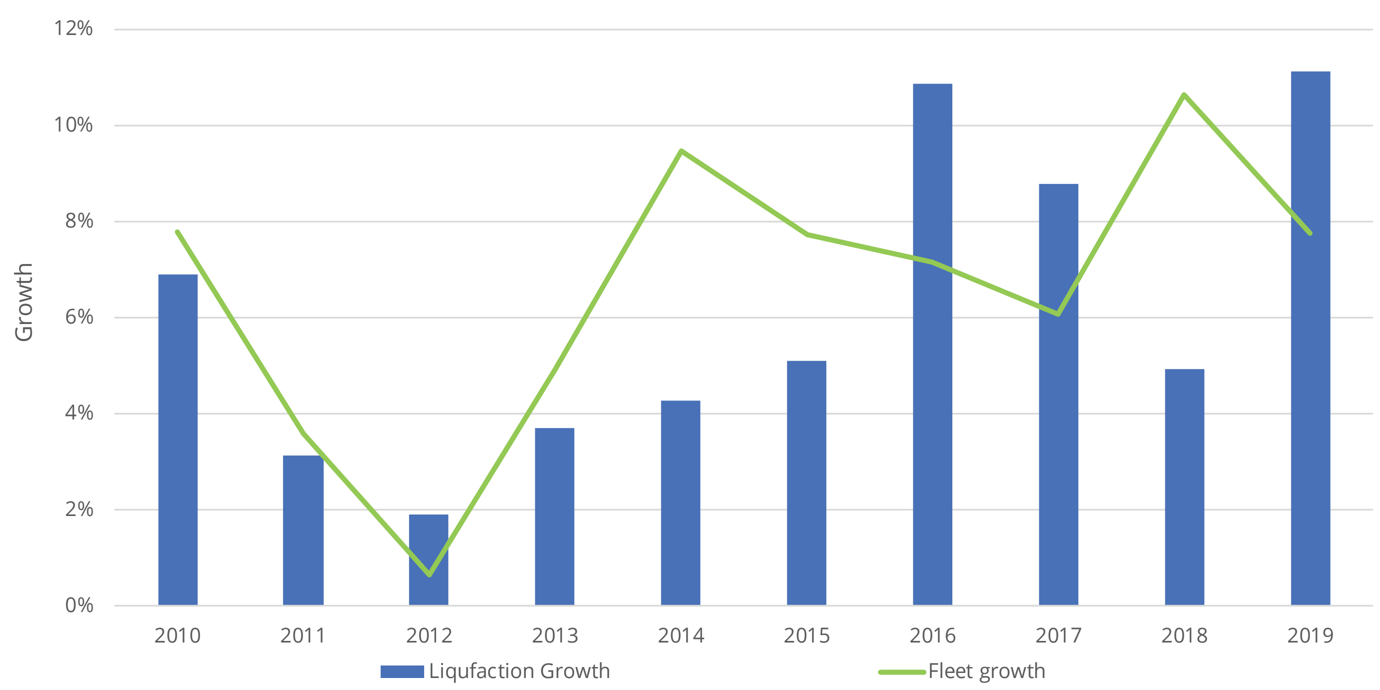
# 5.6.
# CHARTER MARKET

## 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*



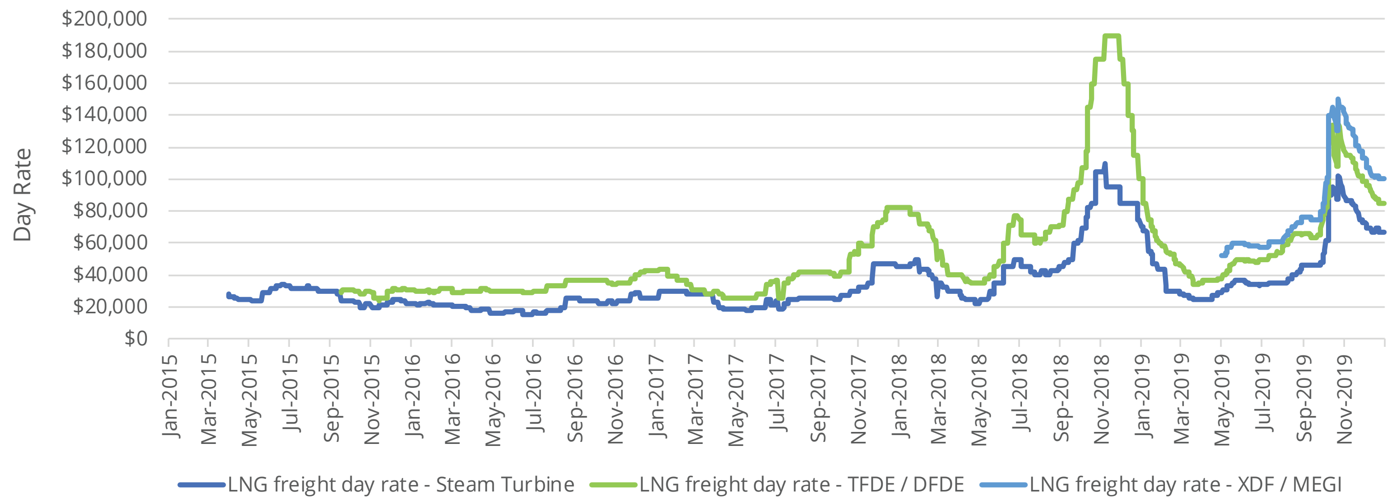

*Source: Rystad Energy*

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.



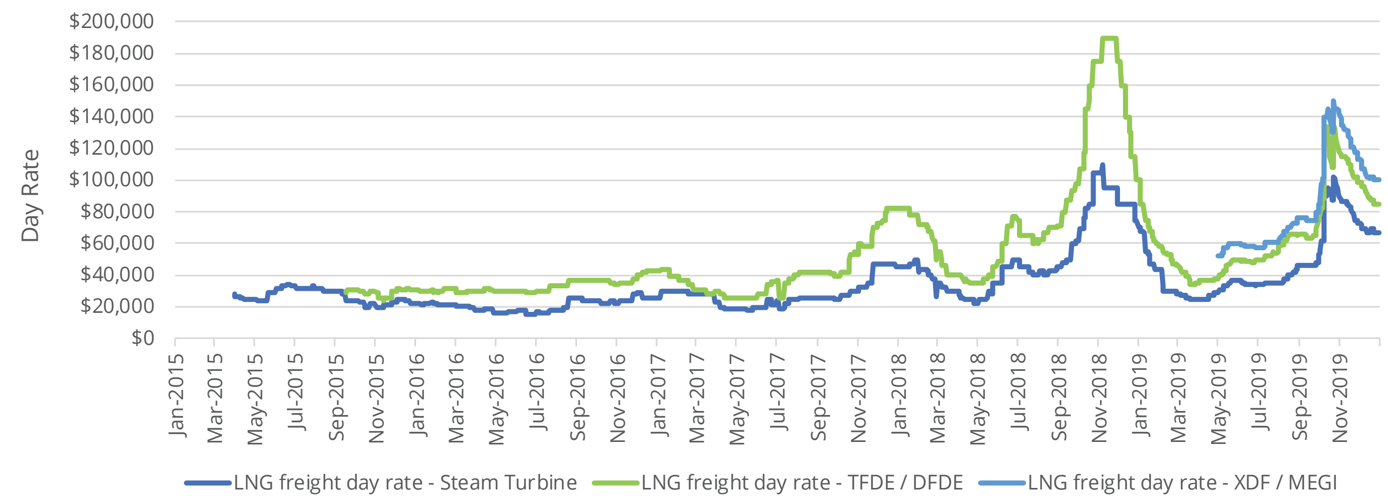


*Figure 5.10: Spot Charter Rates East of Suez in 2019*




*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.