LNG journal

The World's Leading LNG publication

April 2018

36 pages essential LNG news!

In this issue:

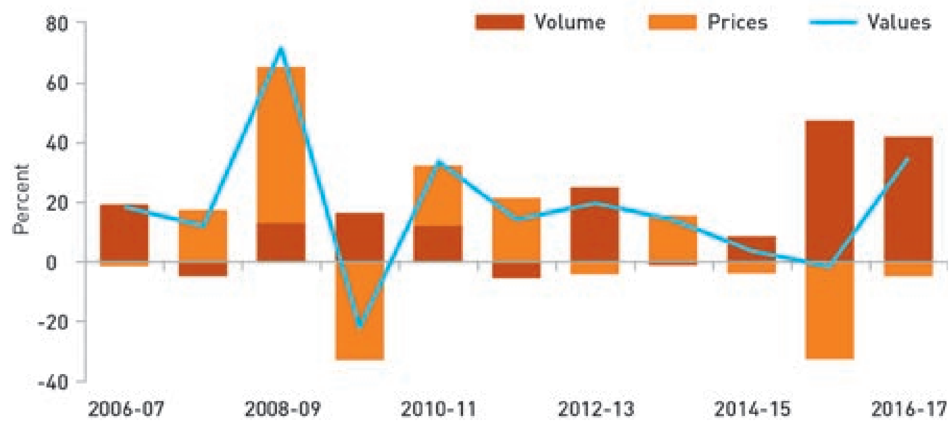
LNG projects Wheatstone, Ichthys and Prelude complete investment wave

Australian plants have become a significant part of the Mining Industry and may benefit from flexibility

Australia may have to demonstrate more flexibility in its liquefied natural gas industry as it moves forward and becomes the world's largest producer, with one area identified as spending on developing more natural gas reserves and importing volumes or shipping domestic cargoes from west to east for the domestic market.

The Australian government's Office of the Chief Economist has published a report on "Flexibility and Growth" in the economy.

Annual growth in LNG export values, contributions from prices and export volumes, 2006-07 to 2016-17



Expansion in LNG production resulted in significant annual growth in the sector

Significance

The period of reform that began in the 1980s shaped a new, more productive and more flexible economy and brought forth the LNG export industry.

"LNG has become a significant part of the Mining Industry. Australia continued to increase its gas liquefaction capacity with the completion of the Gorgon project in Western Australia, and the ramping up of production at three coal-seam gas projects in the eastern states," said the report.

"The expansion in LNG production resulted in significant annual growth in both export value and volume," it stated.

The report said that business investment had fallen in the past couple of years, though there were some signs of improvement.

"Business investment fell in 2016-2017 to A$112.3 billion (US$86.9Bln), down 10.4 percent over the year.

"The fall in business investment is due to a continuation of declining Mining (including LNG) investment from the peak during the mining investment boom, with investment in other industries failing to offset the fall.

Performance

"Falling Mining investment has weighed heavily on recent economic performance, detracting a total of 4.8 percentage points from GDP growth since 2013-2014," said the report.

"The completion of the three remaining LNG projects - Wheatstone, Ichthys, and Prelude - in 2018 will largely mark the end of the mining investment boom," it said.

It noted that these LNG projects will have collectively cost around A$100 billion when completed.

Growth

The end of the LNG investment boom will be followed by a return to more typical spending levels.

"Looking further ahead, Mining investment is expected to stabilise as firms invest to maintain existing capacity and large-scale projects drive investment from 2022," it stated.

"By increasing dynamic efficiency, the reforms allowed Australian firms and workers to realise opportunities that improved productivity and competitiveness, without generating the macroeconomic instability that had plagued the economy in the 1970s," it said.

The report noted that gross domestic product (GDP) growth in Australia during the 1960s was below the Organisation for Economic Cooperation and Development (OECD) average but as the reforms began to take effect, Australia began to grow more strongly than the OECD average.

The first two Australian processing Trains come on stream at the Woodside Petroleum export plant at Karratha in Western Australia in 1989.

In the past, firms had been able to pass on excessive input costs to customers because they were protected from international competition by a tariff wall.

"With falling levels of protection, local firms and workers were forced to improve productivity to remain competitive.

"Lower barriers to trade also provided access to imported goods for consumption and investment at reduced cost, allowing households and firms to benefit from the comparative advantages of Australia's trading partners," it explained.

Queensland

One investment area to be looked at is Queensland's coal-seam gas reserves.

These were written down by 1,341 petajoules last year, more than all the gas estimated in the Cooper Basin, according to the annual reserves estimate by Australian consultancy EnergyQuest,

The country's total gas reserves on a proven plus probable basis fell 4 percent between December 2016 and February 2018, down by 5,355 petajoules from 119,836 PJ to 114,481 PJ.

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"As the reduction in reserves was more than the actual production in that time, the reserves replacement ratio fell into negative territory, meaning Australia failed to replace the reserves it produced," the EnergyQuest report explained.

The impact has been worst in eastern and southern Australia, with gas reserves dropping by 6 percent.

Gas supplies

EnergyQuest Chief Executive Graeme Bethune said significant additional sources of gas supply are needed, with LNG imports.

These have been proposed by two rival projects by AGL Energy and Australian Industrial Energy and they could be part of the solution as they would avoid the pitfalls of large-scale government-directed curbs on LNG export contracts.

"In our view there are two fundamental misconceptions about Queensland gas, one is that there is plenty of it, the second is that the problem in the south can be fixed by diverting modest gas volumes south without violating international LNG contracts," said the Bethune report.

He said the shrinking reserves mean the east coast has two gas challenges, the risk around reserves for long-term LNG contracts with buyers in Asia and the insufficient investment in supply of gas for the domestic market.

...two fundamental misconceptions about Queensland gas is that there is plenty of it [and] that the problem in the south can be fixed by diverting modest gas volumes south without violating international LNG contracts.

Bethune said LNG imports are "cheaper, quicker and far more flexible" than building a pipeline from Western Australia and noted that both Argentina and Egypt, which export gas, both increased domestic supply by importing LNG.

Reserves

In Australia this already occurs with crude oil, which is both exported from, and imported into the country.

The annual reserves assessment found Australia's proven and probable gas reserves fell by 5355 PJ last year, more than production of 4100 PJ. That put the "2P" reserves replacement ratio for gas in 2017 at negative 32 percent.

Most write-downs of reserves were in Queensland, in particular at a field held by Shell's Queensland Curtis LNG, while Australia Pacific LNG and the Santos GLNG plant also cut reserves at fields.

Woodside Petroleum, meanwhile, reported write-downs of conventional gas volumes at the North West Shelf and Pluto ventures in Western Australia, but the proportional impact was greater on the East Coast.

Meanwhile, the government report said that the weaknesses in the current Australian economy and the areas that need reform into the future have been well canvassed by the Productivity Commission.

"What is less well covered is the necessity of reform for Australia to improve its international competitiveness," said the "Flexibility and Growth" report.

"Australia is often described as a small, trading nation. However, the nation's economy is currently ranked 14th largest in the world, of a similar size to the much more populous countries of Spain, Russia and Mexico," it said.

"In other words, Australia is a medium-sized economy

"Australia's international trade profile is unique amongst medium-sized economies. This is partly due to geography but mainly due to policy.

Medium-sized

"Decades of high exchange rates, high tariffs, high trade costs, restrictive trade practices and reluctance to participate in multi-lateral trade negotiations have taken their toll.," it said.

"Australia's integration into the global economy has been weak," it added.

"Mining dominated exports in 2016-2017, with the largest share of total exports and accounting for most top exports by category.

"The value of the top two exports, iron ore and coal, increased by more than 30 percent.

"The rise in export values for iron ore and coal was driven by higher commodity prices due to increased demand from China.

"However, weather-related disruptions constrained growth in the volume of iron ore and coal exports," it said.

Decline

"The large decline in Mining investment that has been detracting from growth in the last few years is now tapering off.

"Record levels of Mining investment in previous years boosted LNG production capacity, which is expected to contribute to growth in the period ahead.

"Business confidence is improving, and businesses have indicated they intend to increase investment in the coming year," said the government's report.

"The pipeline of government infrastructure projects in 2017-2018 is also expected to boost government infrastructure spending growth.

"Looking forward, conditions are in place for a pick-up in economic growth in 2017-2018 and for Australia to achieve 27 years of continuous economic growth.

"The improved picture reflects a stronger global outlook, an improving labour market and the public infrastructure investment pipeline. Consumption growth remains a key economic risk due to high household debt and low wage growth," it added.

"A competitive economy is supported by well-functioning regulations and government initiatives that enable markets to work, while assisting industries to transition effectively," stated the report. ■

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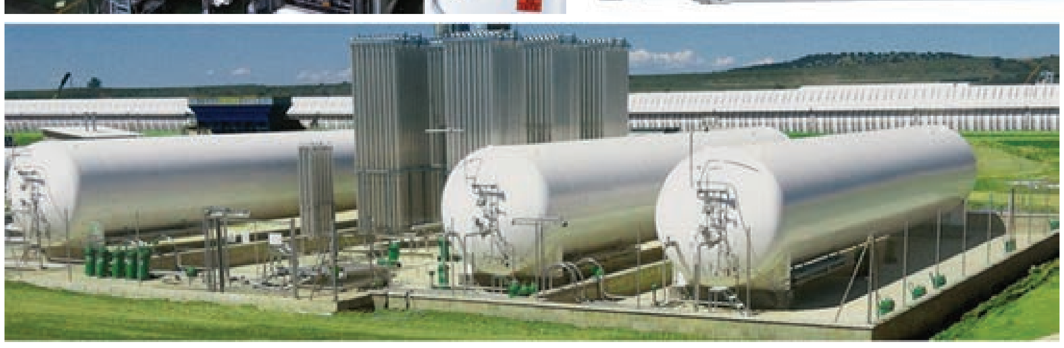

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International Gas Union highlights China case studies to back natural gas and LNG surge

Monitoring in cities of Beijing, Shanghai and Urumqi show clear health benefits of switch to cleaner fuel

The International Gas Union, the body that promotes the use of natural gas and LNG to support global economic progress and human wellbeing and health, has completed important research showing the benefits of shifting from coal to natural gas for residential and industrial energy.

The report highlights case studies in the Chinese cities of Shanghai, Beijing and Urumqi where local authorities have taken significant steps in fuel switching initiatives that have led, or are leading to, real progress in improving air quality without sacrificing economic development.

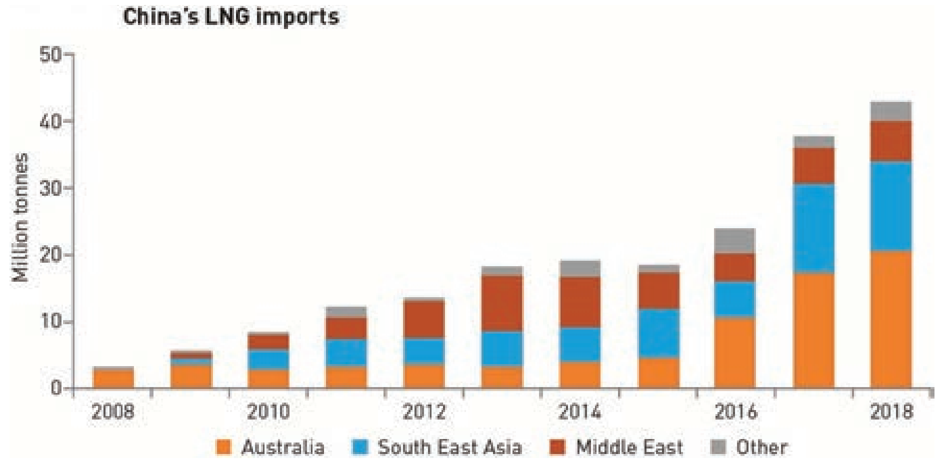
Improvement

The fourth case study examined similar initiatives in Santiago, Chile, a city once known for its poor air quality, where the IGU said a switch to natural gas has played a central role in air quality regulation and improvement. "Of the 5.9 billion people where measurement is available, 4.5 billion of those are exposed to Particulate Matter (PM) concentrations that are at least twice the WHO limit, or above," explained David Carroll, US President of the IGU, set to hold its World Gas Conference in Washington DC in June 2018.

"This, combined with the staggering statistic that PM caused roughly 17 percent of deaths in China in 2015, must signal to authorities that drastic action is needed," stated Carroll.

"More must be done to tackle the severe impact this is having on human health without sacrificing economic growth. Shanghai, Beijing, Urumqi and Santiago are four prime examples of how this is achievable, with natural gas playing a leading role," the IGU President added.

The IGU was established in 1931 and brings together natural gas associations and corporations, including 91 charter members and 51 associate members, representing 97 percent of the global gas industry.



Chinese LNG shipment growth over past 10 years

China has been taking a more active part in IGU activities over the past 10 years and has been steadily increasing its natural gas production and pipeline imports as well as LNG shipments to its network of 16 import terminal.

LNG volumes

Chinese LNG imports in February surged 69 percent compared with the same month a year ago, led by spot shipments and cargoes from Australia, Nigeria and Qatar, though the deliveries were still short of the record volumes received in January 2018.

China received 3.99 million tonnes of LNG in February 2018 compared with 2.36MT in February 2017.

The nation's LNG imports had risen to a record in January of 5.18MT versus 3.43MT in January 2017, up 51 percent.

China imported a record amount of LNG in the winter period as cold winter weather set in and natural gas replaced coal and coke in northern cities under a state campaign to reduce air pollution.

The LNG shipments to China's network of import facilities for all of 2017 were up 46.3 percent compared with the previous year to 38.13MT, also a record.

State efforts

The LNG surge was spurred by a government-led campaign aimed at ending winter air pollution in 30 northern cities and suppliers pointed their cargoes at China in December, January and February.

Chinese imports of natural gas by pipeline, mostly from the Central Asian republics of the former Soviet Union are also increasing.

The switch to natural gas in China comes as the nation recently won the election with a woman candidate for the Presidency of the IGU from 2021.

Chinese candidate Li Yalan, Chairman of Beijing Gas Group Ltd and Executive Chair of the China Gas Association, won the vote to hold the 2021-2024 Presidency of the IGU and part of her duties will be to help organize the 2024 World Gas Conference in Beijing.

The location for the Chinese WGC in 2024 is the China National Convention Centre at Beijing Olympic Park.

China has held its IGU membership since 1986 and holds two seats on the Executive Committee of the IGU, one as an elected Charter member and one as Regional Coordinator for Asia and Asia Pacific.

Leadership

The US holds the current Presidency under Carroll and is hosting the next WGC in Washington on June 25-29 in 2018.

For the 2018-2021 three-year term, South Korea has already been elected to assume the next IGU Presidency and to host the 28th WGC in Daegu, South Korea, in June 2021.

"This is an extremely exciting time for the gas industry, and we strongly believe that China is perfectly placed to lead the IGU in the important role it plays in advocating the use of natural gas," said Carroll.

"Under their leadership, the industry can continue to build on the great work that has already been done bringing together companies, policy makers and other external stakeholders to fully promote and understand the essential - and sustainable - role gas plays as part of the future energy mix," added the current US President.

Before future IGU president Li assumes her leadership role for the global industry, she will serve the IGU as Vice President when Joo-Myung Kang of Korea will assume the Presidency of the IGU following the WGC in Washington.

The conference in the US will mark the culmination of the country's presidency under the theme "Fueling the Future".

For the first time in the 85-year history of IGU, the WGC will be held in a country that is both the world's largest gas producing and consuming nation - the USA.

IGU data for case studies in China and Chile

Beijing: In 2013, the city was experiencing a pollution crisis - dubbed "Airpocalypse" - and over 50 percent of the days that year were ranked as unhealthy or worse for air quality.

In 2014, as the city recorded PM concentrations of 85.9 µg/m3 (almost 9 times the World Health Organization limit), the National Government announced a "war on smog" and intensified anti-pollution policies.

With this in mind, and as the capital city, Beijing was one of the early targets in the government's fight against pollution - in 2015 the city implemented an aggressive coal to gas substitution policy.

In 2017, PM concentrations had dropped to 58 µg/m3 - a 54 percent decrease versus 2016. That year over 4,450 coal-fired boilers were shut down, and 900,000 households have shifted from coal to gas since 2013.

Shanghai: As one of China's megacities, the urgency to address its air quality issues have been top of mind for the city and national authorities, since the late 1990s.

Despite this, in 2000 there were more than 3,800 industrial boilers in operation. That year, Shanghai emitted 464,000 tons of sulfur dioxide (SO_2) and 141,200 tons of smoke and dust. From 2000-2012, Shanghai became the first city in China to embark on a coal-fired boiler retrofit program. This included a focus on enabling supply through completion of transmission and distribution pipe networks, and the enacting of measures for replacing coal with gas boilers

In 2012, the City established a fund for gas project incentives, and introduced coal-free and mostly-coal free areas. In 2015, the entire metropolitan area was required to become coal-free by the end of the year.

By 2016, this had resulted in reduction of all major air pollutants:

- PM2.5 concentration improved by 15.1 percent vs. 2015, and 27.4 percent vs. 2013
- PM10 concentrations dropped by 14.5 percent, vs. 2015
- Total city coal to gas consumption ratio dropped from 43 percent in 2013 to 33 percent in 2016

Urumqi: The city had one of the worst air quality rankings in the country, due to coal combustion, traffic, and biomass burning all emitting harmful aerosols

In late 2012, an air quality improvement initiative was launched to replace coal-fired heating with gas – which grew to 76 percent of the total heating fuel in the 2012/13 heating season from almost none. 12,900 coal boilers were replaced with gas in the first six months

By 2013, this resulted in monthly PM2.5 concentration dropping by 62.8% vs. 2012, a 5 MT reduction in coal consumption, and a 35,000-ton reduction in SO_2 and 17,000 in soot

By 2014, gas had largely displaced coal as the dominant heating fuel, monthly PM2.5 concentrations had dropped by 75.5 percent, and there had been a 50 percent reduction in SO_2 since the 2012 heating season. More importantly, this resulted in a 73 percent reduction in pollution-related lung cancer

Santiago, Chile:

- In 1989, residential heating powered by wood-burning, transport activity, and the use of coal, fuel oil, and diesel by industry had all contributed to the city's PM2.5 levels registering in excess of 68 µg/m3, seven times the recommended WHO level
- Between 1992 and 1998, the city took its initial steps towards air quality regulation, creating a link with Argentina to enable supply of natural gas. Thanks to this, the first gas-fired power plant began generating in 1998
- By 2004, gas supplied 70 percent of industrial and 24% of residential energy, before the supply was interrupted up until 2008. In 2009, however, a new LNG terminal was opened to restore supply and emissions dropped by 1.76 µg/m3, versus the 2004-2008 period
- In 2016, the city has recorded a reduction of 39% of PM10 and 58 percent of PM2.5 since 1990, as well as a reduction of 2.63 µg/m3 of PM from industrial sources

Armed with the latest supporting data, the examples above, and other urban area case studies presented in previous IGU urban air quality studies, the IGU supports policies that reduce GHG emissions and emissions of health-damaging air pollutants such as:

1. Improvement of end-use energy efficiency;
2. Increases in combustion efficiency (reducing or eliminating black carbon and other products of incomplete combustion);
3. Encouragement of fuel switching;
4. Increased use of non-combustion renewable energies.

Supporting testimonial from local stakeholder:

Dr Mauricio Osses A., - Department of Mechanical Engineering, Universidad Tecnica Federico Santa Maria, Santiago, Chile:

"Based on the analysis of PM filters from 1998 to 2012, it can be concluded that the introduction of mass use of natural gas replacing diesel in the industrial sector has had a positive impact on PM2.5 concentrations from industrial sources.

"Specifically, a close analysis of changes in industrial air pollutant emissions that resulted from the temporary interruption of supply from Argentina, and the consequent restoration of supply with the LNG terminal completion, demonstrate a strong positive correlation between using natural gas as fuel and cleaner air." ■

This report is based on the International Gas Union paper: "Case Studies in Improving Urban Air Quality 2018"

For the Record

ANADARKO Petroleum Corp., the US energy company and main stakeholder in the planned onshore Mozambique LNG export plant in southeast Africa, said it received approval from the government for its gas fields development plan. The US company said the go-ahead relates to the Golfinho and Atum fields in the Area 1 licence area of the offshore Rovuma Basin block in Indian Ocean waters. Anadarko said its plan includes the onshore liquefaction plant construction linked to reservoir resources and marked the recent "substantial progress" made on the joint venture. The Anadarko-operated Mozambique LNG project will be the African nation's first onshore development, initially consisting of two Trains with total nameplate capacity of almost 12.9 million tonnes per annum of output. The stakeholders in the other Area 4 licence area of the Rovuma Basin, led by Italian energy company Eni, are already advancing with their separate floating production project called South Coral FLNG. Anadarko has a 26.5 percent stake in the Mozambique Area 1 and Japanese trading house Mitsui holds 20 percent. Indian companies, including Bharat Petro Resources, ONGC Videsh and Oil India Ltd., hold a further 30 percent. The Mozambican state energy company ENH has 15 percent of the licence and Thailand's PTT Exploration & Production has an 8.5 percent shareholding. "We appreciate the support of the Government of Mozambique and are very pleased to achieve this critical milestone providing a further indication of the tremendous progress we continue to make on the project, which will position Mozambique as a strategic global LNG supplier," said Mitch Ingram, Anadarko Executive Vice President for International Operations.

"The approval of the Development Plan continues advancement toward a Final Investment Decision as it builds upon other recent achievements, including the announcement of our long-term Sale and Purchase Agreement with EDF, commencement of resettlement, and our ongoing work to secure project financing," he added. Anadarko said that the foundation project paves the way for significant future expansion of up to 50 MTPA from offshore Area 1. Anadarko disclosed on February 20 that it had signed its supply agreement with French utility Electricite de France (EDF) for a period of 15 years. The US company said the accord was signed on behalf of the Area 1 licence shareholders and would amount to 1.2 MTPA of LNG. The EDF deal takes portfolio sales to more than 5 MTPA. Anadarko had earlier made progress in an agreed citizen resettlement process to prepare the onshore location for the construction of the liquefaction and export plant. The plant will be constructed near the port of Pemba in the northeast Cabo Delgado Province and has involved the resettlement of more than 1,500 households. The project has an initial 30-year lifespan but this may be extended depending on future gas reserve development. Near-shore construction of loading jetties, a material offloading facility (MOF) and flowlines will involve a Marine Exclusion Zone (MEZ) during building and the establishment of a security zone during operations.

APA GROUP, Australia's leading energy infrastructure business with natural gas pipelines spanning every Australian state, said it had entered into a new agreement for gas transportation and storage services from Queensland to southern markets amid plans by several other companies to set up LNG regasification terminals to re-distribute supplies. "This is the 16th contract entered into by APA in the East Coast market since 1 August 2017 and I am very pleased to see this agreement come together and facilitate the flow of more gas into the East Coast domestic market," said APA's Managing Director Mick McCormack. "We work very closely with our customers as our interests are aligned to their requirements. The gas industry is focused on delivering affordable and reliable gas to end users," stated McCormack. "This type of deal is a prime example of the energy industry working together and responding to market conditions. The flexibility provided by APA's interconnected grid and service offerings allows the industry to provide cost effective solutions for Australia's energy challenges," the MD added. APA said it would earn total revenues of around A$40 million (US$31M) over the contracted period of three years from 2018. APA's latest pipeline deal from Queensland to the South comes as a consortium including two Japanese companies said they were planning an LNG regasification terminal near Sydney in New South Wales.

Japanese companies Marubeni Corp. and Jera Co. Inc. have joined an Australian investment and energy company, the Minderoo Group and its Squadron Energy subsidiary, to propose the plan. Minderoo is controlled by Australian billionaire Andrew Forrest and includes a one-third stake in Australian iron ore exporter Fortescue Metals. Marubeni, Jera and Squadron have signed a memorandum of understanding to conduct a joint feasibility study regarding establishing the terminal and gas supply in New South Wales. Another Australian company AGL Energy has sought LNG supply proposals for its import terminal project in the southeast Australian state of Victoria. AGL has chosen Crib Point at Western Port in Victoria as the preferred site for its regasification terminal and import jetty with an affiliated pipeline.

Australia has huge reserves of natural gas that it exports from the states of Western Australia and Queensland and is on track to become the largest LNG exporter, overtaking Qatar by 2019. However, domestic supplies for the East Coast natural gas market, including parts of Queensland, South Australia, New South Wales and Victoria has become a political issue in the country because of rising prices and warnings of future shortages. Most of Australia's LNG production for exports is on the West Coast of Australia. However, three coal-seam-gas-to-LNG export plants have opened in the state of Queensland on the East Coast in the past three years, raising concerns about natural gas shortages in the more populous eastern states. Australia would be the latest Asia-Pacific nation to import LNG or transport it internally by carriers to meet rising domestic demand following import terminal construction by LNG producers Malaysia and Indonesia.

AUSTRALIAN regulators have authorized operators of liquefied natural gas plants in Western Australia and the Northern Territory to coordinate maintenance activities at their liquefaction facilities even as there would be some competition consequences. The Australian Competition and Consumer Commission has authorised the Gorgon, Wheatstone, North West Shelf and Pluto plants to coordinated maintenance along with the future Ichthys LNG project and the Prelude floating LNG venture. "The four LNG producers compete for a limited pool of skilled contractors and specialised equipment to conduct scheduled maintenance," the ACCC explained. "LNG producers can now schedule maintenance together without risking breaching competition laws, reducing concurrent work at their facilities," added the regulator. "This will improve efficiency and maximise LNG production," it said. The companies involved include Chevron Corp for Gorgon and Wheatstone, Woodside Petroleum for North West Shelf and Pluto, Inpex Corp of Japan for Ichthys near Darwin and Royal Dutch Shell for the Prelude FLNG venture offshore northwest Australia.

Some of the Australian LNG plants also supply, or have the ability to supply, natural gas to wholesale domestic markets. When the LNG facilities are offline for maintenance, some gas may be directed to these wholesale markets. "If producers become aware of each other's LNG facility shutdowns as part of this agreement, this information might give them an advantage in gas trading markets," said ACCC Chairman Rod Sims. "To address this, the ACCC has imposed a condition of authorisation requiring the LNG producers to publicly disclose maintenance schedule information that they share with each other. A similar condition applies under an authorisation granted to LNG producers in Queensland in 2016," added the ACCC Chairman. "Information is a crucial component for creating efficient, well-functioning markets. Market-sensitive information disclosed to competitors as part of this process should be available to all participants," said Sims. Authorisation is granted for five years, rather than the 10-year period sought by the LNG producers. "With the evolving nature of the gas markets, there is significant uncertainty about the impact of the proposed conduct on related markets. If the parties wish to seek reauthorisation in 2023, the ACCC will test whether the expected benefits and detriments have arisen and to assess the effectiveness of the conditions," added Sims.

CHENIERE Energy, owner of the Sabine Pass LNG export plant in Louisiana, marked the start of regular LNG shipments to India with a ceremony for the first cargo departing under a long-term supply agreement. Indian natural gas network operator and LNG importer, Gas Authority of India Ltd (GAIL), has a 20-year Sale and Purchase Agreement with Cheniere with cargoes being shipped to import terminals near Mumbai or elsewhere in Asia. Cheniere President and Chief Executive Jack Fusco was at the event at Sabine Pass along with GAIL Chairman and Managing Director B.C. Tripathi and Indian Consul General Anupam Ray. The LNG supply agreement was signed in December of 2011 when India was only building its LNG and gas infrastructure and took effect on 1 March 2018. Under the terms of the accord, Cheniere will make available for delivery to GAIL up to 3.5 million tonnes per annum of LNG. "The commencement of this agreement marks the start of a long and productive relationship between Cheniere and GAIL," said Fusco.

"India remains an important market for LNG, and one that we hope will continue to show signs of growth," added the Cheniere CEO. "We look forward to decades of mutually beneficial cooperation between Cheniere and GAIL, the leading natural gas company of India," added Fusco. GAIL also has LNG contracts for deliveries from Qatar and Gorgon LNG in Australia as well as the newest US LNG export plant at Cove Point in Maryland. Sabine Pass LNG shipments to GAIL will come from Train 4, now in full production, and which gives Sabine Pass 18 MTPA of output with two more Trains still to come on stream at the Louisiana facility. GAIL Chairman Tripathi noted that his company was one of the foundation customers of Cheniere, having signed the contract seven years ago. "With supplies commencing from the US, GAIL will have a diversified portfolio both on price indexation and geographical locations," said Tripathi. "This long-term agreement would go a long way in strengthening the relationship between GAIL and Cheniere and reinforcing India-US trade ties," he added.

CHENIERE Energy said its Sabine Pass export plant in Louisiana was now the largest physical consumer of natural gas in the US on a daily basis and its fifth Train is now almost 85 percent complete. Cheniere gave its update in its latest presentation to investors and said its own Creole Trail Pipeline provides 1.5 billion cubic feet per day of the total 3.9 Bcf/d contracted inlet capacity into Sabine Pass. The Houston, Texas based company said its plant had delivered cargoes to 25 countries and regions across the globe, amounting to 300 shipments exported.

A second US export plant has come on stream in the Lower 48 States, the Cove Point plant in Maryland. About half-a-dozen industrial-scale plants, larger than Cove Point with its single train and 5.25 million tonnes per annum of output, will come on stream in Louisiana and Texas over the next five years. Cheniere's 94-mile pipeline, whose bi-directional capabilities were completed in 2015, interconnects Sabine Pass with a number of large interstate pipelines including Kinder Morgan's Natural Gas Pipeline of America (NGPL), Transco, Tennessee gas Pipeline, Florida gas Transmission, Bridgeline and Texas Eastern Transmission Pipeline.

"A diverse and redundant pipeline network has allowed SPL to reach into almost every North American supply basin," said the company. "SPL's redundancy on pipeline deliverability to the terminal provides the ability to adapt to changing market conditions and manage upstream interruptions," it added. Its four processing Trains in operation have given steady output of 18 MTPA. Train five will take output to 22.5 MTPA and the sixth coming on stream would take the total to 27 MTPA.

"Train 6 is fully permitted and ready to be commercialized, with attractive expansion economics leveraging existing infrastructure," stated Cheniere. Cheniere said its "investment thesis" provides long-term, stable, investment-grade cash flows. "The company's strategy is based on long-term 'take-or-pay' style of commercial agreements (Sales and Purchase Agreements) with investment grade off-takers for approximately 80-95 percent of the expected aggregate production capacity under construction or completed," said Cheniere.

It also forecast that it would make $2.9 billion from annual third-party liquefaction fixed fees once all six Trains are on stream. The company told investors it shown a successful track record developing and operating assets with Trains 1-4 achieving substantial completion within a 17-month time span, all ahead of guaranteed schedules and on budget. "SPL's Train 6 is permitted and the estimated cost to build is $500-600 per ton of LNG, excluding financing costs," said Cheniere. "The current land position at the Sabine Pass site would enable significant expansion opportunities," the company noted.

COMMONWEALTH LNG, the US proposed LNG export plant for the west side of the Calcasieu Ship Channel near Johnson Bayou in Louisiana Cameron Parish has been the subject of a notice of intention from the US Federal Energy Regulatory Commission FERC to prepare an environmental impact statement. The liquefaction facility would have a peak production capacity of 9 million metric tonnes of LNG per year. "The Commission will use this EIS in its decision-making process to determine whether the project is in the public interest," said the FERC notice. "This notice announces the opening of the scoping process the Commission will use to gather input from the public and interested agencies," it added. The Commonwealth project would consist of eight separate sets of facilities, including a 3.7-mile-long natural gas receiving pipeline, extending from existing pipelines operated by Kinetica Partners and Bridgeline Holdings. There would also be four gas pre-treatment units and eight liquefaction trains, each with a nominal LNG production capacity of around 1 MTPA. There would additionally be six LNG storage tanks, each with a capacity of 40,000 cubic metres. The adjacent electric plant would be powered by an 80-megawatt gas turbine and there would be boil-off gas handling systems, utilities, and communications system.

The marine berth would have the size to accommodate LNG carriers with capacity up to 215,000 cubic metres. The FERC explained that members of the public and interested parties could make a difference by providing specific comments or concerns about the venture. "Your comments should focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts," said the FERC. "Individual verbal comments will be taken on a one-on-one basis with a court reporter. This format is designed to receive the maximum amount of verbal comments, in a convenient way during the timeframe allotted," added the Commission. The Commonwealth project developers announced in January 2018 that the Japanese bank Sumitomo Mitsui Banking Corp. would act as its financial advisor to help raise capital and advance the venture. Commonwealth LNG President and Chief Executive Paul Varello said the company was ready to move forward with its innovative LNG investment. "SMBC's experience and reputation in capital asset advice and management will help ensure the stability and predictability of our development project in southwest Louisiana," said Varello. The Commonwealth venture is aiming for construction to begin as early as 2019, with operations to commence by 2022. Its industry partners for equipment include, compressors and drives maker, Siemens of Germany, and US-based consultants CH-IV, a subsidiary of Australian engineering group Clough Ltd.

DEVON Energy Corp. said it had agreed to sell a portion of its Barnett Shale position in North Texas for $553 million with a transaction expected to close in the second quarter. Devon is expected to use the proceeds to pay debts and to develop its other assets in Oklahoma, West Texas and New Mexico. Devon became a major player in the Barnett Shale when it acquired Mitchell Energy, which was credited with launching the hydraulic fracturing boom in the Barnett and other parts of the US. Devon purchased Mitchell Energy in 2001 for $3.1 billion, including its Barnett assets, from fracking pioneer George Mitchell. Mitchell was recognized by the industry before his death in 2013 aged 94 of launching the widespread use of modern fracking techniques that unlocked US shale resources and enabled LNG exports without affecting domestic needs. "Combined with other recent asset sales, divestiture proceeds associated with our 2020 Vision have now reached $1.0 billion," said Dave Hager, President and Chief Executive of Devon. In conjunction with the sale of Barnett assets in Johnson County, Hager said Devon would launch a $1-billion share-buyback scheme consistent with its strategic plan. "We are very confident about Devon's future and, as market conditions permit, we will continue to pursue opportunities to further increase cash returns to our shareholders," he added.

Devon said that net production from the southern Barnett divestiture assets, primarily located in Johnson County, are currently averaging 200 million cubic feet of gas-equivalent per day. "The company's remaining position in the

Barnett Shale primarily resides in Denton, Wise and Tarrant counties, with current production of 680 million cubic feet of gas-equivalent per day," said Devon. "This position contains an inventory of approximately 1,500 potential locations, consisting of undrilled inventory and horizontal refrac opportunities," it added. Oklahoma City-based Devon reported operating cash flow in the fourth quarter of $725 and for the full year reached $2.9Bln, a 94 percent increase compared with 2016. For the fourth quarter, Devon's net earnings totaled $183M, or $0.35 per diluted share. "Devon has reached an inflection point by building operating momentum across its US resource plays and has successfully transitioned these world-class assets into full-field development," CEO Hager said in the February 2018 earnings report. "In 2018 and beyond, with our low-risk development programs focused in the economic core of the Delaware Basin and STACK plays, we expect to deliver a dramatic step change in capital efficiency, achieve attractive corporate-level returns and generate substantial amounts of free cash flow at prices above our base planning scenario of a $50 price for West Texas Intermediate oil," he added. The STACK play is located in the Anadarko Basin area of Oklahoma. The term STACK is derived from "Sooner Trend (oil field), Anadarko (basin), Canadian and Kingfisher (counties)."

FLEX LNG, the Oslo-listed shipping and projects company backed by funds controlled by Norwegian shipping magnate John Fredricksen, said Chief Executive Jonathan Cook has bought a new parcel of shares. Cook purchased 25,000 shares in Flex at 11.31 Norwegian crowns ($1.45) per share as Fredricksen's Geveran Trading renewed a share swaps agreement, according to statements from the Oslo stock exchange. Following the share transaction by Cook, the CEO owns 35,000 shares in Flex. Additionally, a statement from the exchange said Geveran Trading, the company indirectly controlled by trusts established by

Fredriksen for the benefit of his family, has settled Total Return Swap (TRS) agreements underlying 810,000 shares in Flex that expired on 6 March 2018. Geveran subsequently entered into a new TRS agreement for the same number of shares with a new expiry date of 6 June, 2018. "Geveran's affiliated ownership in Flex LNG following this transaction unchanged 191,131,803 shares, constituting 51.94 percent of the issued share capital," it added.

Flex had reported fourth-quarter revenues of $7.9 million compared with $9.8M in the previous quarter. During the three months, it operated two chartered-in LNG carriers to build a market presence. In January, Flex took delivery of the first two of six newbuilds and secured a 15-month to 18-month time-charter for one of the vessels. The vessel "Flex Endeavour" was chartered to German utility and energy company Uniper. The 173,400 cubic metres capacity carrier was handed over at the Daewoo Shipbuilding and Marine Engineering yard in South Korea. The sister ship was named "Flex Enterprise" and was delivered in mid-January. The Norwegian company did not say to whom the second vessel would be chartered. Flex is awaiting delivery of a total of six M-type, electronically-controlled, gas-injection (MEGI) LNG carriers from South Korean shipyards. The Fredriksen-backed company is also continuing to study possible import projects with US development company NextDecade, developer of the Rio Grande LNG export project in Texas.

FLUXYS of Belgium and Snam of Italy, the European natural gas pipeline and LNG terminal companies, have agreed to buy the one-third stake held in Interconnector UK, the bi-directional pipeline linking the UK to Belgium and the Continent, from a Canadian fund. Fluxys, the Belgian transmission network operator and owner of the Zeebrugge import terminal and Snam, its Italian equivalent and owner of the Panigaglia LNG terminal near the Italian port of Genoa, will purchase a 33.5 percent stake owned by the Quebec fund, Caisse de depot et placement du Quebec (CDPQ). Fluxys and Snam exercised their proportional pre-emption right on the CDPQ stake when it was offered for sale. "The transaction enables CDPQ to converge the management of its stake in Interconnector UK into its 20 percent partnership in Fluxys," said the Belgian company. Fluxys put the value of the transaction at around US$103 million. Once the share transfer is completed, Fluxys and Snam, with a 76.32 percent and a 23.68 percent stake respectively, will be the sole ultimate shareholders in Interconnector UK.

"As the initial long-term capacity contracts for the Interconnector pipeline are set to expire in October 2018, the company is preparing for a new market environment in which short-term contracting and commercial flexibility take center stage," stated Fluxys. Fluxys and Snam also recently joined forces with Spain's Enagas to try and build up more European natural gas assets by bidding for a major stake being sold by the Greek government in Greece's natural gas grid operator DESFA. Greece received two binding bids for a 66 percent stake in DESFA being offered by the Greek privatization agency as one of the conditions for the European Union nation's international financial bail-out. The second bidding group comprises the Spanish owner of the Mugardos LNG terminal in northwest Spain, Regasificadora del Noroeste (Reganosa), Romanian gas network owner Transgaz and the European Bank for Reconstruction and Development. A share purchase agreement and a shareholders' agreement for DESFA are scheduled to be signed by April 2018 for the sale to be concluded by June, clearing the way for further international funding of the Greek government.

GAZTRANSPORT and Technigaz (GTT), the French LNG maritime storage tank and technology supplier, said it had successfully ended the test phase for a compact and small-scale solution that can be installed in a ship's structure. GTT said its equipment comprises a Mark III membrane system and is delivered as a block ready to be installed on a vessel. The new GTT system is being marketed under the name "LNG Brick" and provides LNG fuel tanks for capacities ranging between 1,000 cubic metres capacity and 3,000 cubic metres capacity. The French company said that it would also permit the construction of the compact LNG tank elsewhere than at the shipyard which could then integrate it into an LNG-propelled vessel. GTT explained that the new technology will also enable easier management of boil-off gas for small volumes because of its ability to maintain a higher pressure than traditional membrane tanks. GTT said it had entrusted Dongsung FineTec, a Korean company specialising in the production of insulation panels used for GTT's technologies, with the creation of a prototype. The tests were carried out under cryogenic conditions and according to GTT have demonstrated the satisfactory performance of this new system.

"We are pleased to be able to expand our range of membrane containment systems with this reliable, high performance solution," said Philippe Berterottiere, Chairman and Chief Executive of GTT. "Given the current economic environment and LNG price levels, it seems to us to be an appropriate answer to address many of our customers' concerns," added Berterottiere. GTT in February 2018 said it received orders in the first quarter covering equipment for three LNG carriers, as well as the bunkering vessel being built for France's Total and Japanese shipping company Mitsui OSK Lines. The three LNGCs, offering capacities ranging from 174,000 to 180,000 cubic metres, will be built at Samsung Heavy Industries and Hyundai Samho Heavy Industries in South Korea. They will be fitted with GTT's Mark III Flex membrane containment system and deliveries are scheduled for 2020. The bunkering vessel, with a capacity of 18,600 cubic metres, will have Mark III Flex tanks and will be built by Hudong-Zhonghua Shipbuilding in China, which has yards at Nantong and Shanghai. The bunkering vessel, owned by the Japanese-French venture, will be based in northwest Europe and specifically aimed at supplying LNG to future container vessels of French shipping group CMA CGM.

GLADSTONE LNG, the coal-seam-gas-to-LNG plant in the eastern Australian state of Queensland, plans to invest A$900 million (US$700M) in upstream development to underpin production and exports. Shareholders in the GLNG plant, including France's Total, Australia's Santos, Malaysian energy company Petronas and Korea Gas Corp. will be providing the funding to tap into new CSG resources. The GLNG plant receives its feed-gas from the Surat and Bowen Basins of southeast Queensland, via a 420-kilometre underground gas transmission pipeline to serve the two-train liquefaction facility on Curtis Island, near the port of Gladstone. GLNG has been supplying countries such as China and South Korea since starting commercial operations in October 2015. LNG plants using CSG from onshore fields, known as tenements, need supplies from several thousand wells over the lifespan of the liquefaction and export facilities. "As operator, Santos is focused on building gas supply by drilling more wells to increase production, seeking opportunities to extract value from our infrastructure and driving efficiencies to operate at lowest cost," said the company. GLNG is targeting upstream developments in the Maranoa and Western Downs regions of southwest Queensland. "As well as upstream developments around the Fairview, Scotia and Arcadia fields, this investment includes the first year of funding for the new $750M Roma East project which will be developed over the next three years," said Santos.

Brett Woods, Vice President of Onshore Upstream activities for Santos, joined the Queensland Minister for Mines and Energy, Anthony Lynham, at a ceremony to launch the Roma East project, following the drilling of the first of 430 new wells. "This important project will create up to 400 construction jobs and local business opportunities in the Roma area, helping to sustain and boost the benefits of Santos' and GLNG's earlier investments in the region," said Woods. "Roma East will also add nearly 50 petajoules a year to gas production in Queensland in 2020, equivalent to about 8 percent of expected East Coast domestic gas demand this year," according to Woods. "This is great news for both the domestic gas market and our LNG exports," he added. Lynham said the investment by Santos and its partners in the Roma East Field would mean jobs, business opportunities, and royalties for Queenslanders as well as more gas supply for the Australian market and for LNG exports. "We welcome this sign of confidence by Santos in Queensland as an investment destination," added the state minister. The Roma East project will involve bringing on line another 480 wells including drilling around 430 new wells, connecting existing appraisal wells, and drilling pre-development wells in the surrounding areas. The project will also include around 420 kilometres of water, gas gathering and other pipelines. A new water-handling facility for irrigation and over 200 hectares of additional irrigation in the Roma area will improve livestock carrying capacity for some local landholders. "Santos and its GLNG partners have already invested almost $20 billion in regional Queensland since 2011 and this new investment is a huge vote of confidence in the state," said the company.

GOLAR LNG said the global LNG shipping market continued to tighten as a result of demand increasing by around 11 percent, led by China, South Korea and India in contrast to the supply of new vessels that increased by just 5 percent. Hamilton, Bermuda-based Golar expressed its view as it reported fourth-quarter operating income and gross earnings of $2.8 million and $19.4M, respectively, compared with third-quarter losses of $22.9M and $5.5M respectively. The most modern LNG carriers with tri-fuel, diesel-electric propulsion saw their spot rates soar from round $45,000 per day at the beginning of the quarter to three-year highs of around $80,000 to $85,000 per day at year end. "A dramatic reduction in prompt available vessels also resulted in improving rates and utilization for steam turbine vessels. Steady rates and charter activity into the new year were supported by strong underlying demand for LNG that helped sustain firm Asian prices and to prolong arbitrage opportunities through to mid-February 2018," stated Golar. "More recently, there has been a seasonal softening of rates for TFDEs to around $65,000 per day and corresponding reductions in utilization," the company noted. Among Golar's quarterly highlights was the arrival offshore the West African state of Cameroon of the floating LNG production vessel "FLNG Hilli Episeyo".

It has been hooked up to a mooring and has commenced commissioning. In the overall shipping market, Golar said faster than expected coal-to-gas switching saw China demand grow by 48 percent. By year end the Japan-Korea Marker price index was at $11.2 per million British thermal units, the UK benchmark National Balancing Point was at $6.9 per MMBtu and the US Henry Hub was $2.9 per MMBtu. "This price differential created a good export opportunity for US gas into the Asian market, placing further upward pressure on ton miles: 69 percent of 4Q 2017 US volumes went to Asia compared to 48 percent in 4Q 2016," said Golar. The company's US-listed affiliate, Golar LNG Partners, reported an increasing number of emerging markets for LNG requiring smaller volumes on more flexible terms. That's as the partnership posted net income attributable to unit holders of $25.4M and operating income of $40.5M for the fourth quarter compared with net income attributable to unit holders of $26.5M and operating income of $53.3M for the third quarter. "An FSRU that provides for small-scale offloading also allows for other less proximate demand to be met," said the US unit. "Excess capacity that will never be utilized on larger and more expensive newbuild FSRUs undermines this business model. Golar Partners is in a good position to capitalize on this mid-size FSRU market with its remaining FSRU, ships available for conversion to suitably sized FSRUs and access to Golar's proven low-cost conversion model," it said. "Active discussions and negotiations with other potential customers continue, which include projects to convert LNG carriers to FSRUs," the company added.

HOEGH LNG, the Norwegian fleet owner and project developer, said imports through floating storage and regasification units (FSRUs) continued to rise with China, Turkey and Pakistan contributing and there were 13 other global tenders currently pending. "LNG imports through FSRUs rose 3 percent to 33.5 million tonnes in 2017," said Hoegh as it presented its fourth-quarter earnings. At the start of 2018 there were 35 countries importing LNG through regasification plants with a capacity greater than 0.5 million tonnes per annum, including 14 countries using FSRUs. Hoegh said overall tendering activity remained high, and new projects continued to come to market with requests for interest in providing FSRUs. "Such projects, which have been mentioned in the public domain and find themselves in various stages of development, include projects in markets such as Australia, Brazil, Colombia, Cote d'Ivoire, Croatia, Cyprus, Hong Kong, Lebanon, Mexico, Pakistan, Turkey, the UAE and the UK," added Hoegh.

The FSRU fleet consisted of 28 units at start of 2018. Of these, five are converted LNG carriers built in the 1970s and 1980s. The FSRU order book stands at 12 units, with delivery dates from April 2018 through 2021. Hoegh reported fourth-quarter profits after tax of $19.96 million compared with $828,000 in the same three months of the previous year. It also posted record gross earnings of $43M for the quarter, including $5.6M in higher revenue recognition following the conclusion of a contractual audit of reimbursable amounts under an existing time charter. Total revenue for 2017 amounted to $279.3M versus $232.9M in 2016. Annual profits came to $41.05M compared with $14.01M the previous year. "So far in 2018 we have delivered 'Hoegh Giant' on a hybrid LNGC/FSRU contract with Gas Natural Fenosa (Spain), which should have a positive effect on our financial performance from the next quarter," said President and Chief Executive Sveinung J.S. Stohle. "Meanwhile, our business development activity remains focused on securing long-term contracts for our FSRUs under construction, and here we are in advanced stages in several tenders with near-term decision points," added Stohle. "However, while we continue to make progress towards additional FSRU contracts, due to the project delays seen in 2017, the board of directors has decided it prudent to reduce the dividend payments in order to optimize our equity capital," he said.

KOREA GAS Corp., the South Korean network operator and owner of four LNG import terminals, said it received 3.8 percent more shipments in 2017 compared with the previous year. Kogas said its annual imports amounted to 33.06 million tonnes versus 31.84MT in 2016. The company's shipments came mainly from Qatar, Oman, Malaysia, Brunei and Australia. Kogas also has a contract for around 2 MTPA from Yemen LNG, though the facility at Balhaf on the Gulf of Aden was closed during 2016 and 2017 because of the country's conflict. However, the imports by Kogas rose for a second consecutive year after declines in the previous two years. South Korea was the second-largest LNG importer in 2016 after Japan, though it was overtaken by China in 2017. The government of South Korea like China is increasing its use of LNG to replace coal-fired power plants for reasons of air pollution.

There are six LNG import terminals in South Korea and four are owned by Kogas. They are at the ports of Incheon, Pyeong-Taek, Samcheok and Tong-Yeong. The two other terminals are operated by direct importers. One of the two independent facilities is owned by steelmaker POSCO at Kwangyang and has been in operation since 2005. The sixth facility is the Boryeong terminal that started commercial operations in January 2017 for the private companies, GS Energy and SK E&S. Kogas has been increasing its shipments from Australia to replace Yemeni volumes and to boost its own income. The Seoul-based company is a holder of a 15 percent stake in the Gladstone LNG plant in Queensland. The Korean company recently posted a profit of $24 million from the project with two Trains and capacity of almost 8 million tonnes per annum. Kogas said it expected to achieve revenues from Gladstone LNG of $100M in 2018 on the back of increased production from the plant coupled with the recovery of the global LNG prices.

LNG LTD, the Australia-listed company with positions in the mid-scale industry with two North American projects close to construction, Magnolia LNG in Louisiana and Bear Head LNG in the Canadian province of Nova Scotia, is hoping for advances in 2018. "The Magnolia LNG project enters 2018 shovel ready and first in-line to satisfy demand for new LNG supply," said the company in its earnings with losses widening by 2 percent to $13.60 million from $13.31M. It said earnings reflected the company's liquidity management plan and sole focus on completing the marketing of Magnolia LNG's offtake capacity. "Administration expenditure decreased from $6.4M (2016) to $5.0M, reflecting full initiation of the company's cost-reduction program," it stated. "Our team is solely focused on completing our marketing of Magnolia LNG's offtake capacity in order to take a financial investment decision," LNG Ltd said. "The project has all required US Federal Energy Regulatory Commission and US Department of Energy permits and approvals, has construction price certainty through its industry competitive LSTK engineering, procurement, and construction contract price," it added.

Magnolia has a contract with US energy engineers KBR and South Korea's SK Engineering & Construction. The company additionally noted that it had "certainty of gas supply" and equity via a commitment from Stonepeak Infrastructure Partners, as well as debt financing to be led by French bank BNP

Paribas. “For LNG buyers attempting to determine which US greenfield LNG project is most likely to succeed and thus to contract with, you must look no further than Magnolia LNG,” said the company. “Once bankable offtake is sold, Magnolia LNG will move straight to financial close and construction. The project has no other obligations to meet. As LNG developments are considered, Magnolia LNG is the most viable greenfield liquefaction project in the world today,” it added. LNG Ltd said the situation was the same at Bear Head LNG where its regulatory permitting process has been completed. “Bear Head markets itself as a viable outlet for stranded Canadian natural gas resources looking for economic access to global LNG markets, demand, and pricing. Bear Head is uniquely positioned as a key component of an East Coast Canada export strategy,” said LNG Ltd. “In keeping with our promise to shareholders, LNGL managed its liquidity consistent with our stated plans. We closed December 2017 with the company’s total cash position at A$33 million (US$26M), comprising A$29M in cash and cash equivalents plus A$4M in investments in term deposits,” it said, noting that the company had no debts.

MARUBENI Corp. and Jera Co. Inc. of Japan have joined an Australian investment and energy group to reveal plans for a liquefied natural gas import facility near Sydney to make up the domestic natural gas shortfall on the East Coast. The venture said the terminal could initially handle around 2 million tonnes per annum of LNG by 2020 and would be located in the state of New South Wales that includes the largest city of Sydney. The LNG project is backed by Australia's Squadron Energy and its parent company, Australia’s Mindaroo Group, as well as Marubeni and Jera, itself a joint venture between two of Japan’s largest utilities, Tokyo Electric Power Co. and Chubu Electric Power. The Minderoo Group is controlled by Australian billionaire Andrew Forrest and includes a one-third stake in Australian iron ore exporter Fortescue Metals. Marubeni, Jera and Squadron have signed a memorandum of understanding to conduct a joint feasibility study regarding establishing an LNG import terminal and gas supply in New South Wales. “The focus of the feasibility study is a potential project to develop an LNG import terminal at an existing port in NSW, which will include chartering a floating storage and regasification Unit, construction of associated onshore and offshore facilities and provision of gas to local customers in NSW,” they said. “Marubeni has been operating in Australia for over 50 years and has significant energy expertise in Australia, as well as considerable experience in global FSRU business,” said the Japanese companies.

“Marubeni and Jera believe that this FSRU-based project can be completed and commence the supply of LNG to NSW in a timely manner, which will contribute to the stability and diversity of energy sources available to NSW, where gas supplies are expected to remain tight in upcoming years,” they stated. Most of Australia's LNG production for exports is on the West Coast of Australia. However, three coal-seam-gas-to-LNG export plants have opened in the state of Queensland on the East Coast in the past three years, raising concerns about natural gas shortages in the more populous eastern states. Australia would be the latest Asia-Pacific nation to import LNG or transport it internally by carriers to meet rising domestic demand following import terminal construction by LNG producers Malaysia and Indonesia. “This project could provide much needed support to Australian manufacturers within two years, that’s much sooner than other proposed solutions,” said Squadron Energy Chief Executive Officer Stuart Johnston. “The terminal will be capable of bringing the world’s cheapest gas to the east coast market, whether that be from Australia’s existing Western Australian gas resources, or other global markets,” said Johnston. The three locations in New South Wales being considered for the regasification terminal and import plant are Port Botany, Port Kembla and Newcastle with a plan to enter a design phase in early 2018. The consortium could also supply gas to a large-scale gas-fired power station in the state. The latest Australian proposal for imports follows a similar plan put forward by AGL Energy of Australia, a power utility, to build a regasification terminal in the state in Victoria. The AGL proposal for Victoria could start operations by 2020 or 2021.

MYANMAR is expected to begin importing liquefied natural gas by 2020 using floating storage and regasification units to supply three gas-fired power plants already under development. The government has recently given the go-ahead for the three power projects that will run on regasified LNG. Three tendering processes are at varying degrees of completion by three groups constructing the power plants. One gas-fired plant will be built by a joint venture comprising French energy company Total and Germany's Siemens. The 1,230-megawatt plant will be in the southern region of Tanintharyi. A second plant will be located in Yangon and is being constructed by TTCL Public Company of Thailand and Japan's Toyo Engineering with an LNG import facility included. The third project involves Chinese power company Zhefu Holdings and Myanmar's Supreme Trading Co. and involves a 1,350MW plant in the coastal region of Ayeyarwady. Myanmar has been a major natural gas producer since offshore fields were discovered in the 1990s. Despite having an estimated 18.7 trillion cubic feet of natural gas reserves, less than 30 percent of Myanmar’s population has access to electricity.

The government is acting because the current low level of electrification and unreliable power supplies are hindering foreign investment and the development of domestic businesses. Most of Myanmar’s own natural gas resources are currently exported by pipeline to neighbouring countries China and Thailand under long-term contracts. This supply comes principally from the Yadama and Yetagun offshore gas fields. Now electricity needs in Myanmar are expected to surge from 3,000MW to 8,000MW by 2025, leading to the development of the three gas-to-power projects and smaller ventures as well. Up to 70 percent of Myanmar’s power plants in operation are hydroelectric, which means their output varies with the seasons. The government is also hoping to develop an additional smaller gas-fired power network to provide stable electricity supplies during the dry season to back up the Hydroelectric industry.

OPHIR Energy Chief Executive Nick Cooper expressed regret that the UK exploration and production company had been unable to meet its schedule for a final investment decision on the Fortuna floating LNG project planned for offshore the West African state of Equatorial Guinea. Cooper made his statement in the annual earnings of Ophir that saw revenues increase by 76 percent to $189 million compared with $107M the previous year. Ophir said that the completion of project financing on the Fortuna project had taken longer than expected, but all other targets for the joint venture were achieved in 2017. These included the signing of an overall development agreement, the nomination of a preferred supplier for the LNG offtake and the award of upstream and midstream construction contracts. Cooper said that Ophir had taken important steps to adapt its own business to meet key operational targets and to replenish its exploration portfolio. “Nevertheless, we are disappointed to have not yet achieved the Fortuna project FID despite having made significant progress on the project,” he added. The CEO explained that rebalancing of the portfolio and capital expenditure prioritisation away from its prior primary exploration focus has seen Ophir approach sustainability. Ophir and OneLNG, a joint venture between Bermuda-based Golar LNG and global energy services company Schlumberger, have established a joint operating company to develop the Fortuna FLNG venture using Golar’s floating hull technology. OneLNG and Ophir have 66.2 percent and 33.8 percent ownership respectively of the LNG venture company.

Ophir also managed in late 2017 to agree to a 12-month extension to the Block R exploration and production licence offshore Equatorial Guinea from where the feed-gas will come for LNG production. The UK company and its partners had been involved last year in financing discussions with a group of Chinese banks. The Fortuna FLNG project when completed will produce 2.5 million tonnes per annum of LNG from a converted hull of an LNG carrier to be deployed over the gas field. Ophir, Golar, Schlumberger and the Equatorial Guinea government have additionally signed an agreement nominating global commodities company, the Gunvor Group, as the main LNG buyer for the offtake. “Our 2018 priorities are threefold: to deliver the Fortuna project FID; to further monetise our significant contingent resources; and to grow production and cash flow,” said Cooper. Ophir operates a long-life, low-cost production base and has a strong balance sheet with other assets, particularly the producing Bualuang and Kerendan fields in Indonesia. “We sanctioned a fourth phase of development on our Bualuang oil field which will grow production in 2018-19, agreed an increased gas price on our Kerendan field and are in negotiations to double production from this asset by 2020,” the company stated.

PIERIDAE Energy, the Canadian company developing the Goldboro LNG project in the Atlantic Coast province of Nova Scotia, has retained bankers to raise US$10 billion in equity and project financing. Pieridae said it had engaged US investment bank Morgan Stanley & Co and a subsidiary of French bank Societe Generale, SG Americas Securities, to serve as financial advisors for the Goldboro venture. “We are extremely proud to have partnered up with such prestigious organisations as Morgan Stanley and Societe Generale,” said Alfred Sorensen, Chief Executive of Pieridae “The project is a testament to the creditability of Pieridae Energy’s progress to date,” added Sorensen.

The Goldboro LNG project proposes to build an LNG processing facility, storage tanks, a power plant and marine jetties in Guysborough, Nova Scotia. Pieridae has ratified labour agreements to secure tradesmen for the building of the Goldboro plant to produce 10 million tonnes per annum of LNG. The Canadian company has also signed a deal with German utility and energy company Uniper for 50 percent of Goldboro’s initial capacity pursuant to a 20-year, take-or-pay contract. The Goldboro facility will be located at the Goldboro Industrial Park after the company earlier acquired 265 acres of land from the municipality of the District of Guysborough. Goldboro will also have at least two full containment LNG storage tanks, each with a capacity of up to 230,000 cubic metres and the facility is expected to enter production by 2022. Another LNG export project in Nova Scotia is the Bear Head venture being developed by LNG Ltd of Australia.

SANTOS of Australia, the Papua New Guinea LNG plant stakeholder, said the facility and its associated infrastructure would be closed for around eight weeks to complete repairs and restore production following the February 26 earthquake in the Southern Highlands and Hela Provinces of the Oceania nation. The ExxonMobil-operated PNG LNG production facility recently logged an annualized output rate of 8.6 million tonnes per annum and mainly supplies Japan, China and Taiwan. The plant has two storage tanks each with 160,000 cubic metres of capacity and was built with nameplate production of 6.9MT, benefiting from various upgrades and de-bottlenecking since the start-up in 2014. "Santos is deeply saddened by the loss of life and personal injury suffered by communities in Papua New Guinea," said the company "PNG LNG expertise and resources have already been deployed to assist the humanitarian relief and recovery effort, including assessing impacted communities and delivering immediate resource needs," added Santos. Santos has a 13.5 percent interest in PNG LNG which is one of Santos's five core long-life natural gas assets. The other stakeholders in addition to ExxonMobil are the Australia-listed company Oil Search as well as French energy company Total, Japan's JX Nippon Oil & Gas Exploration and the PNG government. All the companies have contributed sums amounting to more than US$2 million towards the relief efforts. Recovery work at the Hides Gas Conditioning Plant is focused on restoring services that provide feed-gas for the liquefaction plant, located northwest of the capital Port Moresby.

"While the plant is safely shut in, there has been some damage to various pieces of equipment and foundation supports that is yet to be fully inspected and repaired," said Santos. ExxonMobil said it would take advantage of the forced shut-down to bring forward previously scheduled maintenance programmes at the liquefaction plant. This means the main customers will have delayed deliveries of LNG. The long-term supply contract holders are China Petroleum and Chemical Corp, known as Sinopec, the Japanese utilities Tokyo Electric Power Co. and Osaka Gas and China Petroleum Corp. of Taiwan. ExxonMobil and the other plant owners are likely to have invoked the "force majeure" clause in the contracts that allows for delays because of natural disasters. "Initial visual inspections of the major processing equipment indicate they have not been significantly impacted," said Santos. "Production wells remain safely shut in. A detailed inspection of some well pads has been hampered due to earthquake-related impacts to the roads. It is hoped this work can be completed within the next week," added Santos. Komo airfield would also remain closed and options are being developed to return the airfield to service as soon as possible. The feed-gas from the Hides Gas Conditioning Plant arrives at the liquefaction plant through a 700-kilometre pipeline. "Surveillance of the pipeline has confirmed it has not been damaged," Santos stated. Plans were recently finalized for the expansion of the existing two-Train plant with the building of three additional Trains and other infrastructure. Earthquakes are common in PNG, a nation of 7 million people and which sits on the Pacific's "Ring of Fire", a hotspot for seismic activity due to friction between tectonic plates. However, this earthquake was the strongest in recent years with a magnitude of 7.5.

SEMPRA Energy, the California-based utility transforming the US Cameron LNG terminal in Louisiana into an export plant, is still planning a Mexican LNG export venture with national Petroleos Mexicano (Pemex) first studied three years ago. Sempra is proposing the project through its IEnova infrastructure subsidiary operating in Mexico, and whose senior executives confirmed the plans were still on when they recently presented IEnova's annual results. The Mexican export plant would be a transformation venture using the existing Energia Costa Azul LNG import terminal completed in 2008 on the Pacific Coast of Mexico. San Diego-based Sempra constructed the terminal to receive imports from Asian LNG producer Indonesia and its Tangguh export project, operated by BP of the UK, when the US still required LNG imports before the shale-gas boom. Now Sempra and Pemex are again pursuing the Mexican export plan at Costa Azul. "We received the three major Mexican permits that are required and we are moving forward with discussions to better understand demand and size the project appropriately," said IEnova Vice President Tania Ortiz Mena. "We expect to make substantial progress on defining the project throughout this year," stated Ortiz Mena during a results presentation.

The Sempra subsidiary signed an agreement with its Costa Azul partner Pemex in 2015 to begin developing a liquefaction facility at the terminal, which is near Ensenada in the northwest Mexican state of Baja California. Costa Azul when it was completed was the first LNG import terminal to operate on the West Coast of North America and is one of three such facilities in Mexico. The other two are at Manzanillo on the Pacific Coast and Altamira on the Gulf of Mexico. Manzanillo mainly receives cargoes from Peru LNG and Sabine Pass in the US, while Altamira receives Sabine Pass shipments and cargoes from countries such as Nigeria. Costa Azul was built to meet demand 10 years ago in both Mexico and the US state of California. IEnova and Pemex said they were now looking to reconfigure Costa Azul to export LNG to markets in Asia and South America. Mexico is a net natural gas importer from the US and the biggest regional customer for LNG. The Mexicans are promoting the idea of using pipeline gas from the US and liquefying it at Costa Azul for export. The terminal is isolated from Mexico's main gas pipeline network and only has a feeder gas line to other inter-connections. However, the nearby Rosarito pipeline links directly to two border-crossing points and indirectly to a third with inter-connections with pipelines near San Diego. Canadian LNG export projects are being proposed in the Atlantic Coast province of Nova Scotia using pipeline natural gas transported north from the US surplus of supplies.

SHELL said the global LNG market has continued to defy expectations with demand growing by 29 million tonnes to 293MT last year, though there was potential for shortages because of a lack of new investment. "Based on current demand projections, Shell sees potential for a supply shortage developing in the mid-2020s, unless new LNG production project commitments are made soon," said Shell in its 2018 Outlook. Japan remained the world's largest LNG importer in 2017, while China moved into second place as Chinese imports surged past South Korea's. "Total demand for LNG in China reached 38MT as a result of continued economic growth and policies to reduce local air pollution through coal-to-gas switching," said the Anglo-Dutch company. "We are still seeing significant demand from traditional importers in Asia and Europe, but we are also seeing LNG provide flexible, reliable and cleaner energy supply for other countries around the world," said Maarten Wetselaar, Shell's Director of Integrated Gas and New Energies. "In Asia alone, demand rose by 17MT. That's nearly as much as Indonesia, the world's fifth-largest LNG exporter, produced in 2017," said Wetselaar.

The company said LNG had played an increasing role in the global energy system over the last few decades. Since 2000, the number of countries importing LNG has quadrupled and the number of countries supplying it has almost doubled. "LNG trade increased from 100MT in 2000 to nearly 300MT in 2017. That's enough gas to generate power for around 575 million homes," it explained. However, LNG buyers continued to sign shorter and smaller contracts. The number of LNG spot cargoes sold reached 1,100, the equivalent of three cargoes delivered every day. This growth mostly came from new supply from Australia and the US. "The mismatch in requirements between buyers and suppliers is growing. Most suppliers still seek long-term LNG sales to secure financing.

But LNG buyers increasingly want shorter, smaller and more flexible contracts so they can better compete in their own downstream power and gas markets," noted Shell. "This mismatch needs to be resolved to enable LNG project developers to make final investment decisions that are needed to ensure there is enough future supply of this cleaner-burning fuel for the world economy," it added.

SINGAPORE LNG Corp., operator of the city-state's import and re-export facility on Jurong Island, said its fourth storage tank is scheduled to be completed in the next couple of months as the facility broadens its activities as a regional hub. The fourth tank has even larger capacity than the other three at 260,000 cubic metres and will offer LNG traders more options and flexibility. The facility currently has three storage tanks in service, each with a capacity of 188,000 cubic metres and 540,000 cubic metres in total. The terminal is owned by the Singapore Energy Authority and is located on a 40-hectare plot at the southern tip of Jurong Island. It has been in operation since 2013 and can handle the largest LNG carriers from Qatar. When it started up it became the first open-access, multi-user LNG regasification terminal in Asia.

Its current services include receiving shipments for Singapore's own energy needs and additionally offering storage and re-loading for exports. SLNG is also building a fuel bunkering business in cooperation with the Maritime and Port Authority of Singapore. The terminal works in close cooperation with Pavilion Energy, owned by the Singapore wealth fund Temasek. Pavilion has rights to access tank capacity on a segregated basis for LNG storage and reloading services. This supports higher volume of LNG trading activities, small-scale LNG opportunities, LNG breakbulk and vessel cool-down services. Pavilion is working with industry players to trade LNG indexed to the Sling, the Singapore Exchange's LNG Index Group, to support more trades based on the index.

STABILIS Energy, the US liquefied natural gas producer and supplier, said it had completed the acquisition of a majority interest in Prometheus Energy, a small-scale US LNG distributor. Stabilis, based in Beaumont, Texas, did not disclose the value of the transaction. Under the acquisition agreement, Prometheus will operate as the independent LNG distribution subsidiary of Stabilis. Stabilis provides LNG to heavy-horsepower users of diesels and crude-based fuel in the oil industry. The company opened its 120,000 gallons per day LNG production facility in George West, Texas, in January 2015 to service industrial and oilfield customers in Texas and the greater Gulf Coast region. “Prometheus provides mobile and stationary LNG solutions to industrial, utility, pipeline, high-horsepower and other remote customers,” said Stabilis. Stabilis said that Prometheus would continue to purchase LNG from multiple producers to optimize fuel cost for its customers.

“We are pleased to announce the acquisition of Prometheus Energy,” said Casey Crenshaw, Chief Executive of Stabilis. “Prometheus was a pioneer in the LNG industry and it remains the premier small-scale LNG distribution and service company in the world,” added Crenshaw. “We believe this transaction will allow each company to grow aggressively in LNG production and distribution, respectively,” he stated. Jim Aivalis, CEO of Prometheus, said his acquired company remains fully committed to its current customers and business model. “We are experiencing strong and growing demand for reliable and cost-effective natural gas solutions from our customers,” explained Aivalis. “The combination with Stabilis will provide Prometheus with added resources to better serve our customers as their need for LNG expands,” he added.

STEELHEAD LNG, the developer of an export project offshore Vancouver Island in the Canadian Pacific province of British Columbia, has named an experienced energy executive to head its pipeline division and to join its board of directors. The company said that R.L "Randy" Jespersen, a former Chief Executive of Canadian energy company Terasen Gas., would bring 35 years of experienced to ongoing discussions on securing feed-gas supply for the venture now named Kwispaa LNG to reflect native North American First Nation participation.

Jespersen’s career began with Dome Petroleum followed by Amoco in Calgary and Houston, Texas. In 1996, he joined Terasen Inc. (now FortisBC), where he held various senior roles including Vice President of Gas Supply. “During this period, the British Columbia-based gas distribution company achieved an unprecedented level of growth through corporate acquisitions and major project developments, including construction of the Southern Crossing pipeline, Whistler natural gas extension and the Mt. Hayes liquefied natural gas storage project on Vancouver Island,” said Steelhead. Jespersen assumed the role of President and CEO of Terasen Gas in 2002 until his retirement in 2010. “I am very impressed by the calibre of the Steelhead LNG team and by the company’s low-cost pathway to developing the Kwispaa LNG project and pipeline that is competitive in the current market,” said Jespersen.

“It creates an attractive pricing opportunity for British Columbia and Alberta producers, and benefits for all British Columbians, including our First Nations partners,” he added. In addition to his executive appointments, Jespersen also previously served as Chair of both the Canadian Gas Association and the Western Energy Institute. He was also on the Executive Committee of the Business Council of British Columbia.

“As a respected leader in the North American energy sector, who has contributed greatly to the economic and environmental framework of Western Canada, Randy Jespersen will play a significant role in the company as we continue our quest to connect clean, low-cost Canadian natural gas with energy hungry global markets,” said Steelhead LNG Chief Executive Nigel Kuzemko. Steelhead aims to source Canadian natural gas feedstock for the Kwispaa LNG facility from various producers in northeast British Columbia and northwest Alberta.

The company is currently assessing a proposed pipeline corridor that would extend from the Chetwynd area to Williams Lake area, southwest to Powell River, across the Strait of Georgia, terminating at the Kwispaa LNG site. Steelhead said it anticipated making a route decision in mid-2018, following early discussions with potentially affected Indigenous communities to integrate feedback into the design. Steelhead has additionally retained four groups of the world's largest project contractors, including KBR and CB&I of the US and TechnipFMC as it narrowed its field of bidders to complete front-end engineering and design work for initial production of 12 MTPA of LNG. The company also said in January 2018 it was considering ordering two floating liquefaction and storage hulls at a cost of US$500-million from South Korean shipbuilder Hyundai Heavy Industries. Steelhead is hoping to advance with its project down the regulatory path backed by First Nations relationships. Hyundai said it had been chosen by Steelhead to conduct front-end engineering design for the hulls and to eventually build them for the liquefaction and export facility. The South Koreans explained that its customer was scheduled to begin operations with the FLNG facilities in 2024 on the coast of Vancouver.

Steelhead’s plans to liquefy natural gas sent through underground pipelines to its floating facilities and to export around 6 million tonnes per annum of LNG. Steelhead is one of the few remaining Vancouver-based energy companies focused on LNG export projects and recently changed the name of the former Sarita Bay venture to Kwispaa LNG. The name change for the Sarita project was suggested by the Huu-ay-aht First Nation, an indigenous community located on the west coast of Vancouver Island and the development partner of Steelhead. The Kwispaa project has received unanimous support from the tribal council of the small First Nation of 750 people.

The planned liquefaction plant venture at Sarita Bay is still in the preliminary engineering and conceptual design stage. The Kwispaa FLNG plant would be located on First Nation land about 10 kilometres north of Bamfield in BC and about 70 kilometres southwest of Port Alberni, where Steelhead had previously planned another project.

Steelhead has already been awarded a Canadian National Energy Board export licence for up to 24 MTPA of exports from the Sarita Bay site.

TAMROTOR Marine Compressors (TMC), the Norway-based equipment supplier, has signed a contract with Samsung Heavy Industries to supply a marine compressed air system to four LNG-powered shuttle tankers the shipbuilder is constructing for Teekay Offshore. TMC said it would deliver a complete compressed air system to each of the four shuttle tankers, including compressors as well as adsorption air dryers. Samsung is building four Suezmax-size, shuttle tankers for Teekay Offshore. TMC said the newbuild tankers will be constructed based on Teekay Offshore’s new “Shuttle Spirit” design which incorporates proven technologies to increase fuel efficiency and reduce emissions, including LNG propulsion technology. “Once on the water, they will be the most environmentally-friendly shuttle tankers ever built. The vessels will be delivered in 2019 and 2020 and provide shuttle tanker services in the North Sea,” stated TMC.

TMC said it would make its first delivery in the third quarter of 2018. Contract values were not disclosed. “Samsung Heavy Industries has selected TMC’s compressors for a wide range of newbuild vessels in recent years, for a number of different end-clients,” said Hans Petter Tanum, TMC’s director of sales and business development. “It is fantastic to be asked to be involved with these environmentally ground-breaking shuttle tankers too,” added Tanum TMC, whose headquarters are in Oslo, is the world’s leading supplier of compressed air systems for marine and offshore use. It previously signed a contract with Samsung to supply a marine compressed air system to a newbuild floating storage and regasification unit ordered by Hoegh LNG. Under that contract, TMC will deliver a complete marine compressed air system consisting of two 44-kilowatt service compressors and two 44-kW control air compressors. The systems will be installed on a 170,000 cubic metres capacity FSRU scheduled for delivery in the second quarter of 2019. It will have a regasification capacity of a minimum 750 million cubic feet per day.

TEXAS LNG Brownsville, the liquefaction and export plant proposed for the Gulf Coast, said the US Coast Guard issued a recommendation to the US Federal Energy Regulatory Commission confirming the suitability of the Brownsville Ship Channel for the facility's marine traffic in terms of safety and security. Texas LNG is an independent, Houston-based export company founded by two international and US oil and gas industry veterans, Vivek Chandra who is Chief Executive, and Langtry Meyer who holds the post of Chief Operating Officer. Regulators, led by FERC, are considering the plans by the company to construct a liquefaction plant on a 625-acre site located at the South Texas Port of Brownsville's deepwater ship channel. The plant will enable the export of 4 million tonnes per annum of LNG to established and developing markets using abundant nearby pipeline feed-gas resources. Texas LNG said full FERC approval and a final investment decision for the development of the liquefaction project in Brownsville are expected in 2019. The first phase of production of 2 MTPA of LNG is expected to begin in 2023. Texas LNG said it had secured long-term offtake term sheets from LNG buyers in China, Southeast Asia and Europe, and is planning to begin pre-FID detailed engineering in 2018 upon closing of its current funding round. In its review of Texas LNG's suitability, the Coast Guard addressed public comments that raised a number of issues, including safety, security, potential environmental impacts, economics and the physical characteristics of the ship channel.

In addition, the Coast Guard considered not only Texas LNG's expected carrier traffic, but also recognized other traffic transiting through the Channel, including offshore rigs, aircraft carriers, fishing vessels, recreational vessels and traffic from other proposed LNG projects. "The Coast Guard concluded that the waterway is suitable to handle current and anticipated incremental traffic from the Texas LNG facility," said Texas LNG. The plant and export terminal will be designed to accommodate LNG carriers with capacities of up to 180,000 cubic metres. The Brownsville Ship Channel has a current depth of 42 feet (12.8 metres), with full US Congressional authorization to deepen the channel to 52 feet (15.8 metres).

The total inbound transit from the Gulf of Mexico sea buoy (pilot boarding area) to the future Texas LNG terminal berth is approximately seven miles (11km). "This is a notable advantage over most other proposed US LNG projects in Texas, as well those in Louisiana, where transit distances can be significantly longer," the company said. Texas LNG has already signed up other project participants, including leading technical, commercial, financial and legal experts. These include plant builders, South Korea's Samsung Engineering and KBR of the US and LNG equipment-maker and Air Products. Samsung Engineering is also a minority equity owner in Texas LNG and strategic partner (with KBR) responsible for all engineering, construction and procurement.

TRANSCANADA Corp., the Canadian and North American pipeline and infrastructure operator, has launched a new open season on its Nova Gas Transmission Ltd. (NGTL) system expansion for binding capacity commitments at the Empress-McNeill export delivery point onward to the US border for volumes formerly expected to be shipped as LNG from British Columbia to Asia. The open season is for an estimated 280 million cubic feet per day of firm service commencing in November 2021. This capacity offering follows a successful open season that was completed in January 2018 for 1.0 Bcf/d of expansion capacity at the same delivery point, with service commencing between November 2020 and April 2021, and underpinning a recently announced $2.4 billion NGTL System expansion. “This earlier open season was over-subscribed and industry has expressed strong interest for additional market access,” said TransCanada. The company said this new open season will close on March 15, 2018. TransCanada is facilitating economic access for their natural gas to key export markets, including access to Eastern Canada and the US Northeast through TransCanada’s Canadian Mainline and downstream systems. The NGTL has already executed contracts for incremental firm receipt service totaling 620 million cubic feet of natural gas per day beginning in April 2021. These contracts will connect new supply in the low-cost Montney shale-gas of northeast British Columbia that was formally expected to be transported to LNG projects on the Pacific Coast such as those previously planned by companies like Petronas of Malaysia. It will also service as a route for the Deep Basin and Duvernay plays to the NGTL system and provide shippers access to various local and pipeline export markets.

The pipeline expansion was previously mostly linked to a final investment decision on the Pacific NorthWest LNG project of Petronas and to other plans for liquefaction plants on the BC coast. The Petronas partners in its cancelled LNG venture were China’s Sinopec, Japan Petroleum Exploration Co., Indian Oil Corp. and Petroleum Brunei. TransCanada said the existing NGTL system was a strategic asset now committed to providing shippers with timely and competitive options to connect with growing basin supply to downstream markets throughout North America. The incremental receipt and export delivery contracts will drive the NGTL expansion programme that will include 375 kilometres (233 miles) of large diameter pipeline, compression facilities, meter stations and other associated facilities. This will include the Empress-McNeill export delivery point on to other Canadian points and to the US border. The existing NGTL system delivered more than 4 trillion cubic feet of natural gas in 2017. Around 40 percent of deliveries were in the Canadian provinces of BC and Alberta, a further 19 percent went to markets in the Pacific Northwest and the US state of California, 19 percent was transported to the US Midwest, and 22 percent to Eastern Canada and the US northeast through various interconnected pipelines. Key points on NGTL include: East Gate: In the southeast portion of the NGTL system, the East Gate interconnects with TransCanada's Canadian Mainline (near Empress, Alberta) and TransCanada's Foothills Pipeline (near McNeill, Alberta). West Gate: In the southwest portion of NGTL, the West Gate interconnects with TransCanada's Foothills Pipeline (British Columbia). Upstream of James River: These are throughputs in the northwest portion of the NGTL system. This system contains flows from the Horn River and the Groundbirch pipelines (part of NGTL).

US Coast Guard officers have approved the St Johns River in Florida as suitable for liquefied natural gas marine container traffic from the Jacksonville export terminal proposed by Eagle LNG Partners. The Coast Guard's opinion was sent to the US Federal Energy Regulatory Commission as part of the permit process for the Eagle LNG development. The proposed project consists of three small-scale liquefaction Trains capable of producing up to 1.65 million gallons of LNG per day, the equivalent of around 1 million tonnes per annum. "The LNG will be transported to markets in the Caribbean and Latin America for power generation, and to local and regional markets," according to the permit application. The LNG would be shipped in containers on board cargo

Diary of events

May
Flame Gas and LNG conference
14-17 May 2018
Hotel Okura, Amsterdam
The Netherlands
https://energy.knect365.com/flame

June
27th World Gas Conference
25-29 June 2018
Washington Convention Center
801 Mount Vernon Place Northwest
Washington, DC 20001, USA
http://wgc2018.com

September
Gastech
17-20 September, 2018
Fira Gran Via Conference Centre
Barcelona, Spain
www.gastechevent.com

ships rather than on large-scale carriers. Eagle LNG submitted a formal filing for the project to the FERC in the first quarter of 2017. The construction is preliminarily scheduled for the first half of 2018 and start-up and commissioning is likely by the end of 2019. A letter of recommendation was sent to the FERC as part of the advance of the Eagle project towards receiving full permits.

"It conveys the Coast Guard's recommendation on the suitability of the St. Johns River for LNG marine traffic as it relates to safety and security. The review focused on the navigation safety and maritime security aspects of LNG vessel transits along the affected waterway. Our analysis included an assessment of the risks posed by these transits and possible risk management measures," said the Coast Guard. "During the review, we consulted a variety of stakeholders, including members from the Jacksonville Port Authority, the Jacksonville Marine Transportation Exchange, the St. Johns Bar Pilot Association and the Florida Docking Masters Association," it added. The Coast Guard said it additionally sought the opinions of the owners of the neighboring facilities to the Eagle's export terminal and the Jacksonville Fire and Rescue Department. Eagle said it would receive natural gas by pipeline at its plant and liquefy it, temporarily store the produced LNG and periodically load LNG onto ocean-going vessels. The LNG would be exported to nations in the Caribbean who currently use heavy fuel oil or diesel for power generation and would also be sold to shipping companies for use as marine fuel. The project will occupy a 194-acre parcel of land that is zoned for industrial activity and in an area that currently hosts other bulk fuel terminals. The proposed facility will receive natural gas transported by a local utility through existing and expanded pipelines located adjacent to the Jacksonville project site. Eagle LNG will also procure electric power from the Jacksonville Electric Authority. ■

Argentina sets date for first Atlantic licensing round to complement shale gas efforts amid LNG doubts

South American nation pursues combination of offshore exploration and onshore shale-gas projects

LNG importer Argentina is planning to launch its first offshore licensing round in almost three decades in mid-2018 in the hope of developing fields off its Atlantic coast like those in neighbouring Brazil and to complement its growing efforts in producing energy from onshore shale plays.

Argentine Energy Minister Juan Jose Aranguren said the first round of licensing would be launched in June or July for 240,000 square kilometres in three zones of the continental shelf.

Surveys

Argentina hired several foreign survey and research data companies to pinpoint in 2017 the likely blocks to be set aside for auctions.

Norway's Spectrum was commissioned to conduct a seismic survey in cooperation with state-run oil and gas company Yacimientos Petroleiferos Fiscales (YPF) and the Ministry of Energy.

That survey provided Argentina with the first ever detailed seismic grid over the under-explored frontier area, allowing for basin-wide studies and prospect interpretations for the forthcoming licence rounds.

Spectrum said that the expansion of the Atlantic Margin seismic coverage would soon allow it to offer a modern 2D library from French Guiana in the north through Brazil to the edge of Argentine offshore waters in the south.

The Australian company Searcher Seismic has also surveyed the area.

"Argentina's continental shelf is one of the few offshore regions in the world that is practically unexplored," said Energy Minister Aranguren in Buenos Aires.

"There is a high probability that the subsalt basin that exists on the coast of Brazil continues south," he added.

"The exploration will be for 10 years due to the higher risks associated with offshore drilling," he stated.

Reforms

Argentine state-run energy company Integracion Energetica Argentina (IEASA), formerly known as Enarsa, also chose the main winners of its latest LNG cargo tender with four companies supplying the first batch of shipments.

Overall Argentina is importing 68 cargoes during the next 12 months and has found suppliers for 22 cargoes in its latest tender.

> *'Argentina believes it is still on track to cease LNG imports as substantial shale-gas supplies from its estimated 308 trillion cubic feet of technically recoverable gas resources begin to flow'*

The tender for deliveries from May through August saw three international commodities market players chosen among the main suppliers. They are Trafigura, Gunvor and Vitol.

A fourth main supplier will be UK energy major BP with shipments from Trinidad.

Shipments

Of the 22 LNG cargoes heading for Argentina in the May-August delivery window, nine of them will be unloaded at the floating storage and regasification unit (FSRU) in Bahia Blanca, a port in the south of Buenos Aires province.

The balance of 13 cargoes will be shipped to the GNL Escobar facility, another FSRU docked on the Parana River, located about 30 miles north of Buenos Aires.

Argentina started importing LNG in 2008 as natural gas shortages were affecting industry and power needs.

Despite its estimated 802 trillion cubic feet of unproved, technically recoverable shale gas resources, Argentina's dry natural gas production declined each year from 2006 to 2015, and the country has shifted from a net exporter of natural gas to a net importer.

However, in 2015, natural gas production increased for the first time since 2006, as ongoing efforts to increase production from key shale gas areas in Argentina aimed to reduce its imports of pipeline natural gas and LNG.

Once one of the largest natural gas exporters in South America, Argentina was a net importer of natural gas by 2008.

Imports, which accounted for 23 percent of Argentina's natural gas consumption in 2015, came by pipeline from neighbouring countries and as LNG from sources such as Trinidad as well as from West Africa.

Direction

The country's President Mauricio Macri is currently leading an overhaul of the energy industry as part of his reforms to help meet the nation's oil and gas needs.

Since taking power in December 2015, Macri has backed faster development of the Vaca Muerta shale reserves and other unconventional plays in the southwestern Neuquen Basin.

The Vaca Muerta formation has similar geological properties to the US Eagle Ford shale play near the Gulf of Mexico in Texas in terms of its depth, thickness, pressure and mineral composition.

Argentina is banking on Vaca Muerta shale-gas success to offset LNG

Argentina believes it is still on track to cease LNG imports as substantial shale-gas supplies from its estimated 308 trillion cubic feet of technically recoverable gas resources begin to flow from the Vaca Muerta shale wells by 2022.

Output

While shale gas production, which began in 2013, has been growing at more than 20 percent per annum, it has not been enough to replace falling output of conventional gas.

More than 600 vertical and horizontal shale wells have been drilled and completed in the Vaca Muerta shale play since 2010.

According to the Argentine Ministry of Energy and Mines, shale gas production reached 64.6 billion cubic feet (Bcf) at the start of 2016.

Argentina's YPF, the most active operator in the Vaca Muerta shale play, has initiated joint venture pilot project agreements with partners such as Royal Dutch Shell, BP, Total, Chevron, ExxonMobil, and Norway's Statoil to develop the shale plays.

Statoil signed its deal in January 2018 with YPF. Under the agreement, the

Argentine LNG terminals are at Bahia Blanca, a port in the south of Buenos Aires province, and at GNL Escobar (above), an FSRU docked on the Parana River and located about 30 miles north of the capital

partners will each take a 50-percent interest in the 38,800-acre Bajo del Toro block, with YPF acting as the operator.

Under the accord, which is typical of the type being signed, Statoil will pay YPF US$30 million to cover the costs the Argentine company has already incurred with relation to the block, and also pledge US$270 million for future capital expenditure.

Chevron invested $1.5 billion when it struck a joint venture deal with YPF three years ago.

Joint ventures

YPF's joint ventures with Total, BP, Shell and several other firms are focused on ensuring long-term oil and gas production growth.

Argentina plans to spend $21.5 billion on new oil and gas production ventures with partners over the next five years.

YPF will sell some assets to raise the funds necessary for its efforts to increase production.

Although Vaca Muerta may have similar geologic properties to the Eagle Ford play in the US, the production history of the Eagle Ford may be difficult to replicate in Argentina.

From 2010 to 2013, more than 10,000 wells were drilled in the Eagle Ford, and average initial production per well nearly tripled over that period.

Prices

However, since 2014, the decline in world oil prices has resulted in lower upstream capital expenditures as operators prioritize their spending.

While drilling costs in Argentina have declined, they are still higher than YPF's target costs. The average drilling and completion cost of a horizontal well in Vaca Muerta was estimated to be $11.2 million as of the start of 2016 compared with $6.5 million to $7.8 million in the Eagle Ford.

The economic competitiveness of Argentina's shale-gas resources will depend on the costs of domestic drilling and completion.

Analysts said Argentina was also lagging because of relatively high labour and imported equipment costs, shortages of specialized shale rigs and limited proppant capacity.

Argentina is the third country in the world, after the US and Canada, to commercially develop shale gas and tight oil.

In addition to receiving LNG shipments, Argentina also imports pipeline gas supplies from Bolivia and Chile to meet a third of its estimated 180 million cubic metres per day of demand.

Power

Under the nation's recent reforms, the state energy company Energia Argentina Sociedad Anonima (Enarsa) had its name changed to Integracion Energetica Argentina (IEASA).

Officials explained that among the changes there would be a sale of the state's share in thermoelectric power plants and these would be transferred to IEASA.

The new company would also implement the construction of the Santa Cruz dams in Patagonia and the completion of the electric power plant at Rio Turbio.

The Santa Cruz project will take five years to construct at an estimated cost of $4.7 billion, financed by Chinese banks. The hydroelectric venture will help meet around 5 percent of the country's energy requirements.

Argentina produced about 136 billion kilowatt hours (BkWh) of electricity in 2016 and is now the second-largest consumer of electricity in South America after Brazil.

Natural gas accounted for about half of Argentina's electricity generation last year, followed by a 28 percent share of hydroelectricity.

Most of the remaining power generation is fueled by petroleum products or nuclear and very small amounts of coal and other renewables. ■

Outlook covering industry advances examines place for LNG and other fuels in transport and power

For the first time UK major BP shares the outcomes of its analysis with the wider world

Liquefied natural gas will play a crucial role in being a fuel for transport and power generation as new technologies are applied to more efficient hydrocarbon production and for vehicle and maritime transport.

UK energy major has just published its BP Technology Outlook, marking "the first time we have shared the outcomes of our analysis with the wider world," according to the company.

The analysis shows that the world is not running out of resources for its energy needs. Fossil fuels of oil, gas and coal, along with uranium, are plentiful while the alternatives of renewable energies do not deplete by definition.

"With existing and incremental technology advances, we have abundant and technically accessible resources to meet foreseeable global primary energy demand out to 2050 and beyond," said BP Group Chief Executive Bob Dudley.

Resources

"The extent to which each fuel is used depends on many factors. These include technology and policy but also capital," he added.

"An abundance of supply and a fall-off in demand growth have driven energy prices down and constrained the funds available for investment.

"Such price falls compel the industry to develop new technologies to reduce costs; however, the situation reminds us that energy is influenced by the interplay of many different factors.

"Technologies such as enhanced oil recovery, advanced seismic imaging, and digitization will have a huge impact on which of the available fossil resources we develop, how, where and when," stated the CEO.

BP explained in the report that innovation would not only help to sustain the supply of hydrocarbons, it would enable renewable resources - most notably solar and wind - to be more competitive, changing the merit order of investment and resource development.

> *'BP notes that transport is set to become cleaner with LNG-powered trucks - as well as LNG used for ship propulsion'.*

Biofuels

In terms of energy's end use for transport, liquid fuels, including biofuels, are likely to continue as the major source of transport fuel for at least the next 30 years.

"They will be used more efficiently as vehicles and engines become lighter and smarter. In power generation, as well as increasing contributions from renewables, new opportunities such as a global shift towards natural gas, improved energy efficiency and, ultimately, carbon capture and storage technology will help us to move towards a lower-carbon future," the company said.

Meanwhile, further falls in the costs of renewables and developments in areas such as battery storage and smart energy systems will widen options in an already competitive market.

"Society's challenge is how to balance mitigating climate change while at the same time providing the energy security and affordability that drives socio-economic development. The energy industry can assist in the transition to a more sustainable economy if policy frameworks are developed to promote investment in lower-carbon technology," added BP.

BP said the aim of its technology publication was similar to the BP Energy Outlook 2035, and the BP Statistical Review of World Energy, to "make a valuable contribution to the debate about how best to shape a secure, affordable and sustainable energy" in the future.

Natural gas

The UK energy major said that technology would first help to unlock future natural gas and oil resources.

"We calculate that around 45 trillion barrels of oil equivalent of oil and gas were 'originally in place' of which only 2 trillion boe have been produced to date.

"Ongoing development of these reservoirs can produce enough to meet anticipated global demand for the foreseeable future.

"The availability of resources therefore is less of a challenge than the impact of consumption on the sustainability of the environment," it added.

"While here we discuss our analysis of the potential scale of recoverable resources, we do so mindful that governments, supported by many businesses and citizens, are increasingly seeking to limit carbon emissions by using less energy and shifting towards lower carbon fuels," said the BP report.

Impact

"This is likely to have an impact on the proportion of these resources produced, relative to other forms of energy," it added.

A significant volume of fossil fuels will still be used as part of the transition to a more sustainable future energy mix, including the use of natural gas as a substitute for coal, and it is therefore relevant to understand the role of technology in finding, producing and consuming fossil fuels.

The most significant change to the oil and gas resource base in the past decade has been the development of production from shale and 'tight' (or low-permeability) rocks, particularly in the US.

"Estimates of shale resources, not only in the US but around the world, have more than doubled the total estimated volumes of oil and gas in place globally with development potential.

Conventional natural gas (excluding imported LNG) and coal remain the lowest-cost options for generating electricity in North America and most other regions through to 2050.

With a higher carbon price, natural gas is increasingly advantaged over coal.

"Without a carbon price and excluding CO2 transportation and storage costs, adding CCS to coal and CCGT plants would increase the cost of generation by \$25/MWh and \$16/MWh respectively by 2050.

LNG trucks

BP notes that transport is set to become more efficient with LNG-powered trucks and other vehicles fuelled by compressed natural gas and liquefied biogas - as well as LNG used for ship propulsion.

"Continued improvement in the efficiency of internal combustion engines (ICE) and vehicles will reduce emissions.

"The cost of supplying biofuels will fall, particularly second-generation biofuels made from grasses, wastes and other non-edible agricultural matter.

"Despite their high energy efficiency, electric vehicles or fuel-cell vehicles still need significant technological advances to compete with ICE vehicles on cost," stated BP.

"Vehicles powered by liquid fuels, including biofuels, are likely to dominate global sales through to 2035 and beyond.

"We expect the average efficiency of new light-duty vehicles offered to the market to improve by 2–3 percent per year as a result of increased hybridization and improved powertrains combined with advanced fuels and lubricants.

Displacing diesel

"LNG could displace diesel from some of the heavy-duty market, with CNG increasing its share of the light-duty vehicle market in regions with low-cost natural gas and policy support," said BP.

The long-term trends discussed in the technology publication depict an energy sector of increasing diversity and complexity.

New resources are becoming available, led by shale oil and gas. Energy prices have returned to their traditional pattern of volatility. Policies and regulations on environmental

issues vary from country to country and may develop in different ways.

"Within this complex and uncertain picture, two trends that will have a bearing on the entire framework are clear.

"Firstly, we will need to deliver more energy to more people at lower cost," said BP.

"Secondly, the growth in energy demand needs to be met while reducing GHG emissions and making a transition to a lower-carbon energy system," it added.

Metrics

"The key metrics that will show how these trends evolve are the amount of energy used and the level of GHG emissions.

"Both are influenced by a series of factors. Energy supply and demand are governed by factors such as economic and demographic growth and the capacity of technology to produce resources cost effectively. "Emission levels are influenced by policy and regulation, for example, by the pricing of carbon through taxation or emissions trading, by subsidies and quotas for renewable energy, and by regulations such as building standards and tailpipe emission limits for cars," it said.

"In transport, we expect vehicles to remain fuelled mainly by oil-based liquid fuels and, to a lesser extent, biofuels. We expect engines and vehicles to become lighter, more efficient and smarter, complemented by advanced, increasingly efficient lubricants and fuels.

"In the medium to long term, we can expect progressive decarbonization in the transport sector with a greater move toward hybrid and electric passenger cars.

"Liquid fuels will be much more difficult to displace from commercial transport such as shipping, trucks and aircraft, however, due to their high energy density," it stated.

"Our research covered eight geographic regions that resulted in 30,000 possible routes or 'value chains', extending from the harvesting of primary energy resources to their conversion into products and to their consumption.

"At each stage of the value chain, we considered various options for how each energy source or product might be transported.

"For instance, natural gas can be transported by pipeline, shipped as LNG or converted to electricity and transported as 'gas-by-wire'.

"Technology underpins each element of every chain and the way in which technology develops will shape how we think about energy and use it in the future.

"Consequently, each value chain has a unique set of technologies, costs, efficiencies and sustainability implications that influence the choices we make," it said.

Recoverable

BP said the technically recoverable oil and gas resource base could be increased by around 1.9 trillion boe to 4.8 trillion boe by applying today's best available technologies to conventional fields and including unconventional resources.

The latter require different production methods and extraction technologies and include oil and gas found in shale rock, "tight" formations and oil sands.

Although no technological breakthroughs are required to develop unconventional resources, there are likely to be significant above-ground challenges.

These will include government policy, infrastructure, supply chains, public opinion and consumer preferences.

Between now and 2050 technological developments will also drive improvements in field recovery factors. This is particularly the case for unconventional gas and for conventional oil.

These factors, when combined with the discovery of new oil and gas resources from exploration, could potentially add another 2.0 and 0.7 trillion boe respectively, over and above the potential from current best available technologies. ■

Exploitation of recondensing equipment on LNG carriers to minimize cargo losses during transport

Maksym Kulitsa and David A. Wood, FSRU and LNG consultants, report on key LNG transportation issue

LNG carriage at sea is struggling to minimize cargo consumed onboard during sea transport, compared with the decades when the LNG shipping fleet consisted only of steam-powered ships.

The past decade or so has seen the introduction of dual-fuel diesel electric (DFDE), and M-type electronically controlled gas injection (ME-GI) and other fuel-efficient marine engines on LNG carriers (LNGCs), as well as improved LNG cargo tank designs.

Tank designs

The latest cargo tank designs have lower normal boil off rates (NBOR), e.g., GTT Mark V system has 0.08 % vol/day, compared to older tank designs with NBOR of 0.125 to 0.150 % vol/day, common on much of the steam-powered LNG carrier fleet.

LNG carriers traditionally use boil-off gas (BOG) in the engine rooms as fuel on both DFDE and steam vessels.

Only a few LNGCs are fitted with a reliquefaction plant (e.g., Q-flex and Q-max LNGC of Qatar's Nakilat fleet).

Shipboard reliquefaction plants (Matyszczak & Kaszycki, 2011; Gomez, 2013; Vorkapić et al., 2016) are not a standard feature on LNGCs, while they are always present on LPG carriers.

The reason for such choice is dictated by the market as LNG reliquefaction plant is complex and expensive compared to LPG reliquefaction, as it requires heat exchangers involving cryogenic temperatures.

Traditionally, LNGCs handle excess BOG via Gas Combustion Unit (GCU) on DFDE or Steam Dump (SD) on steam vessels, which provides no commercial benefit from that BOG and leads to additional atmospheric emissions.

Relatively recently, compact recondensing equipment has become available to the LNG industry (Hayashi et al., 2016) See Figure 1.

As a consequence, it is now commercially viable to fit recondensers, not only on FSRU, but also on some LNG carriers (Lee, 2017) to handle surplus BOG produced in the LNG tanks.

Older design of recondensers are conventional packed-column BOG recondensers, developed and optimized for use in onshore LNG regasification plants, which are heavy and costly, with restricted commercial value for offshore applications.

More recent designs, such as Sulzer's static mixer BOG recondenser are much smaller and lighter, making them ideal for shipboard applications, and have been fitted in FSRU's since 2011.

Scalable

The availability of cheaper and more scalable recondensers means that they have become an integral part of FSRU design, in a rapidly expanding FSRU fleet.

Moreover, they can also be installed on LNGCs to reduce, and potentially minimize, BOG consumptions during sea transport (i.e., consumption of BOG other than for essential fuel to power the vessel).

Conventional Boil-off Gas to LNG Recondensers Versus Compact Static-Mixer Designs Suitable for Offshore Applications

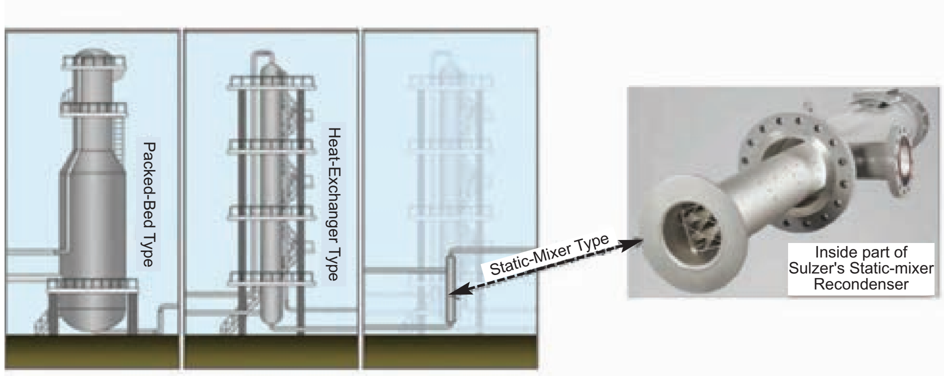


Figure 1 (Left): Conventional recondenser designs versus new recondenser designs for land-based regasification terminals, modified after (Hayashi et al., 2016); Right: Sultzer's compact BOG recondenser for onshore and offshore deployment

TYPICAL PRESSURE OPERATING RANGES AND LIMITS FOR LNGC MEMBRANE TANKS

Cargo Tank Side Alerts and Actions	% of MARVS DFDE	250 MARVS Pressure in mbarg	% of MARVS Steam	Vapor Header Side Alerts and Actions
Cargo Tank Pressure Relief Valve Open	100%	250	100%	
	92%	230	92%	Auto-Vent Valve Open for Vent Mast #1
If Tank Pressure Continues to Rise Above this Limit Relief Valves will Open				
High High (HH) Pressure Alarm				
Auto-action > Spray Pump Stop	88%	220	88%	High High (HH) Pressure Alarm (No action)
Auto-action > Spray Valve Close				
	84%	210	84%	*Auto-Vent Valve Closed for Vent Mast*
High (H) Pressure Alarm (No action)	80%	200	80%	High (H) Pressure Alarm (No action)
Highest Operating Pressure Limit				
	76%	190	76%	Cargo Tank Pressure Range for Ballast Voyage
	28%	70		
Normal permitted range of tank pressures at any operating conditions that are allowed by tank manufacturer and no any auto-actions, interlocks or trips are set up within this range	36%	90	36%	Cargo Tank Pressure range for Laden Voyage/ FSRU mode
	16%	40	16%	
	20%	50	20%	Design Normal Operating Pressure for Laden Voyage
	20%	50		*Fuel Oil Back Up Mode Stop*
Lowest Operating Pressure Limit				
If Tank Pressure Continues to Fall Below this Limit Tank-Related Systems will Start to Shutdown				
Low (L) Pressure Alarm (Action)	12%	30		Fuel Oil Back Up Mode Start (Auto Action)
>Cargo Pumps Start Interlock				
Low Low (L) Pressure Alarm on Steam Ship		25	10%	Fuel Oil Back Up Mode Start (Auto Action)
>Fuel Oil Back Up (Dual Burning Mode) Activated on Steam Ship				
Low Low (LL) Pressure Alarm and Tank Protection System (TPS) Activated				Low Low (LL) Pressure Alarm
				Auto-action > GCU stop on DFDE ship
Auto-action > All Pumps Stop	8%	21	8%	*Auto-action > Engine Room Gas Burning Stop*
Auto-action > High Duty Compressor Stop				*Auto-action > Low Duty Compressor Stop*
				> Forcing Vaporizer and Spray Pump Stop
	1%	3	1%	Very Low (VL) Pressure Alarm and ESDS Activated
Cargo Tank Vacuum Relief Valve Open	-4%	-10	-4%	

Table 1: Typical operating ranges of membrane tanks and various safety systems and alerts activating on DFDE and steam-powered LNGCs

Compared to FSRUs, usage of recondensers on LNGCs has significant limitations, due to their different operating patterns, LNG cargo temperature requirement and lower maximum allowable tank pressure settings (MARVS).

Consequently, recondensers may be efficiently used on LNGCs to handle excess BOG only periodically and not on permanent basis. Nevertheless, that limited use can be commercially and environmentally worthwhile.

In recent years, LNG use as a bunker fuel has expanded for small and large vessels. The LNG bunkering operations involve ship-to-ship transfers of LNG to vessels' fuel tanks, which also generate BOG-handling issues, and recondensers can be used to address these issues.

Bunkering operations are characterized by intermittent flow of high-pressure BOG with a significant peak BOG flow of short duration.

One LNG bunkering vessel's recondenser systems design (Ryu et al., 2016) uses a spray recondenser to temporarily store the transient BOG inflow (at about -100oC and 5.1 bar pressure) by condensing it with sub-cooled LNG and store the condensed liquid in a dedicated tank.

Here, we propose novel concepts and a design basis for potential development of recondenser usage on standard LNGCs, used for LNG cargo transportation while the vessel is at sea, to reduce and, ideally, avoid GCU /SD usage.

Also, optimum ways to incorporate recondensers in LNGC BOG-handling strategies are proposed for recondenser use that would enhance performance of LNGC for low associated capital requirement.

Recondensers can Improve BOG Handling on LNGCs: Recondensers are different from reliquefaction units (RU) due to the physical methods employed.

EXTRACTS FROM CARGO UNLOADING SURVEY REPORTS FOR TWO LNGC CARGOES INDENTIFYING BOG CONSUMED DURING VOYAGE		
Type of LNG Carrier	Steam-powered LNGC	Tri-Fuel Diesel Electric LNGC
Vessel design capacity (cubic metres)	138,000	150,000
Bill of lading cargo volume loaded (cubic metres)	137,002	148,421
Tank pressure during loading as reported by custody transfer management system (CTMS) (mbarA)	1010	1088
Volume of cargo unloaded (CTMS) (cubic metres)	132,114	148,809
Tank pressure during unloading as reported by custody transfer management system (CTMS) (mbarA)	1152	1181
Voyage duration (days)	20.58	7.82
Corrected loss of cargo during voyage (cubic metres)	1,866.7	4,876.8
Intransit loss of total cargo (%)	3.55%	1.24%
Estimated LNG boil-off during voyage (BOR) (%/day)	0.17%	0.14%
Vessel LNG boil-off design limits (NBOR) (%/day)	0.15%	0.15%
Conclusion	BOG exceeded design limits	BOG was within design limits

Table 2: Example cargo survey report at unloading destination conducted by an independent cargo surveyor made after an LNGC delivered its cargo to an FSRU (extracts only). CTMS refers to custody transfer management system. Such information makes it possible to compare actual average BOR achieved during a specific voyage with the declared NBOR design limits. Modified after Kulitsa & Wood (2017d)

Recondensers change the state of fluids without heat (energy) being removed from the fluid system. To do this they require a large flow of cooler liquid (i.e. LNG from the cargo tanks) to condense the boil-off vapor. In contrast, RU extract energy from the fluid systems via cryogenic heat exchangers, making them expensive in terms of capital and operating costs.

Cooling and condensing is achieved by bringing cold pressurised (4 to 5 bar) LNG liquid in direct contact with BOG that is injected under modest pressure (3 to 4 bar). The latent heat of condensation is removed from BOG and transferred to the cold LNG liquid (i.e. the cooler LNG liquid becomes warmer by absorbing latent heat from BOG) resulting in a warmer total LNG liquid outflow (which combines the heated cooler LNG and condensed BOG). The major positive effect of this process is achieved by the reduction in volume associated with the gas to liquid phase change; LNG liquid occupies about 250 times less space than BOG at 110-150 mbarg and at about -145oC temperature.

In addition to the phase transformation resulting in warmer LNG outflow from the recondenser, a little extra energy is added to the LNG by pumps, friction and heating in pipe system (i.e., process induced heat). Thus, the recondenser return flow always contains more energy compared to the cooler LNG and BOG from the cargo tanks fed into the recondenser.

On FSRU and land-based regasification plants this warm LNG is sent to the regasification plant, where it is transformed (rapidly warmed) into send-out gas. In addition to this main regasification outlet route, recondensers on FSRU can also be used in recirculation or partial recirculation mode, returning warm LNG back to the cargo tank, during regasification stoppages or interruptions (Kulitsa & Wood, 2017a).

On FSRU 700 mbarg MARVS this may continue from a few days up to a week, with the warm return LNG gradually heating the LNG cargo in the tanks but preventing or delaying the operation of the GCU/SD, and thereby saving a significant amount of the LNG cargo.

This process is time-limited because the rising saturated vapor pressure (SVP) of the LNG cargo, due to increasing LNG temperature in tank, ultimately reaches the specified safe limit for tank pressure (i.e., upper-operating-tank-pressure limit, which varies from vessel to vessel). At that limit safety equipment (GCU, SD or similar) must be engaged to control pressure, holding it at that limit, until regasification and gas send-out resumes.

Applications of recondensers on LNGC are significantly more limited compared to FSRU. The main reasons are:

1) low MARVS of their cargo tanks (typically 250 mbarg) (Table 1);
2) operating and contractual requirement to deliver cold LNG (low SVP) cargoes to their customers; and
3) no involvement of regasification and gas send out as part of their BOG shipboard handling configuration.

Moreover, some LNG receiving terminals may have requirements to deliver cargoes with maximum specified SVP, and many LNG receiving facilities have tanks rated at 250 mbarg MARVS. This limits their ability to take delivery of warmer (higher SVP) cargoes.

Prolonged use of a recondenser on an LNGC in recirculation mode (the only option) back to tank will inevitable heat up the LNG cargo and increasing its SVP and tank pressure.

Advantage

One advantage for recondensers, operating on an LNG carrier (in recirculation mode) during the laden voyage is the full cargo onboard, providing a huge mass of cold LNG in-tank that assures slow heating of the bulk LNG cargo.

Independently of recondenser use, the LNG cargo is being slowly heated by the constant heat ingress into the tanks through the tank insulation. The recondenser can only be used on an LNGC while tank pressure and the SVP of the LNG remain within the safe operating limits specified by the tank design.

Typically, that is 180 to190 mbarg (upper-operating-tank-pressure limit) for tanks with 250 mbarg MARVS. However, it may be less than that limit if cold-cargo delivery requirements apply (i.e., SVP /tank pressure according to receiving terminal / customer contract requirements). Once such SVP and pressure limits are reached, recondenser operations must cease and the GCU/SD engaged to control tank pressure from that point forwards.

The use of recondensers on LNGC has its greatest potential impact when the ship is travelling at low speed (i.e., low engine room demand for BOG as fuel), or is at anchor. In such conditions, excess BOG (defined as remaining BOG above that used as engine room fuel) reaches a maximum and leads to greater GCU/SD consumption.

Installed

With a recondenser installed, GCU /SD usage may be avoided or delayed (Kulitsa & Wood, 2017a) thus saving cargo from loss ("loss" means here any cargo saved for later utilization for power the LNGC or deliver to a customer).

Recondensers are likely to be more beneficial for DFDE LNGCs which inherently consume less BOG as fuel than steam-powered ships. GCU use is inevitable in normal DFDE sailing conditions, and sometimes at short notice, when the low duty compressor (LDC) protection systems activate and "pack" the cargo tank vapor space with a recycled hot vapor, e.g., when LDC overpressure protection engages due to low discharge flow requirement to engine room (Kulitsa & Wood, 2017b).

Once engine-room-fuel requirements fall below the NBOR specified for the tank system then tank pressure inevitably rises, potentially at a hazardous rate, when the ship is at anchor, if the GCU is not used. BOG to satisfy the vessel's NBOR must be removed from the cargo tanks in order to maintain tank pressure stable (Kulitsa & Wood, 2017c).

Yet, during every DFDE LNGC voyage there are certain operating conditions that cause engine demand for fuel to be much less than NBOR.

Occasionally, such low-demand periods are significantly extended due to delays, transits of canals or other shipping choke points at low speed, manoeuvring in port or waiting allocation of a jetty berth or anchorage position.

Potential

During such periods, the recondenser has its best potential to be used on an LNGC

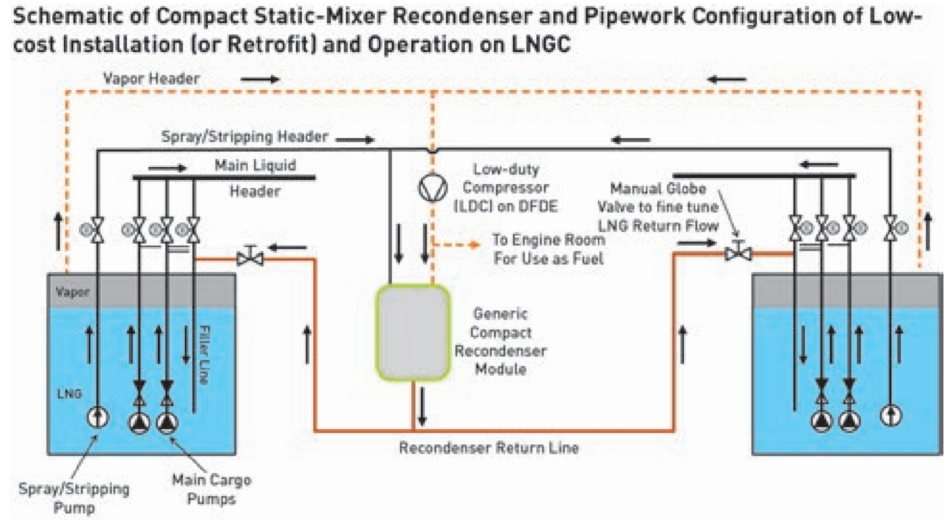


Figure 2: Schematic of recondenser and associated pipework configuration for effective operation and low-cost installation on LNGCs

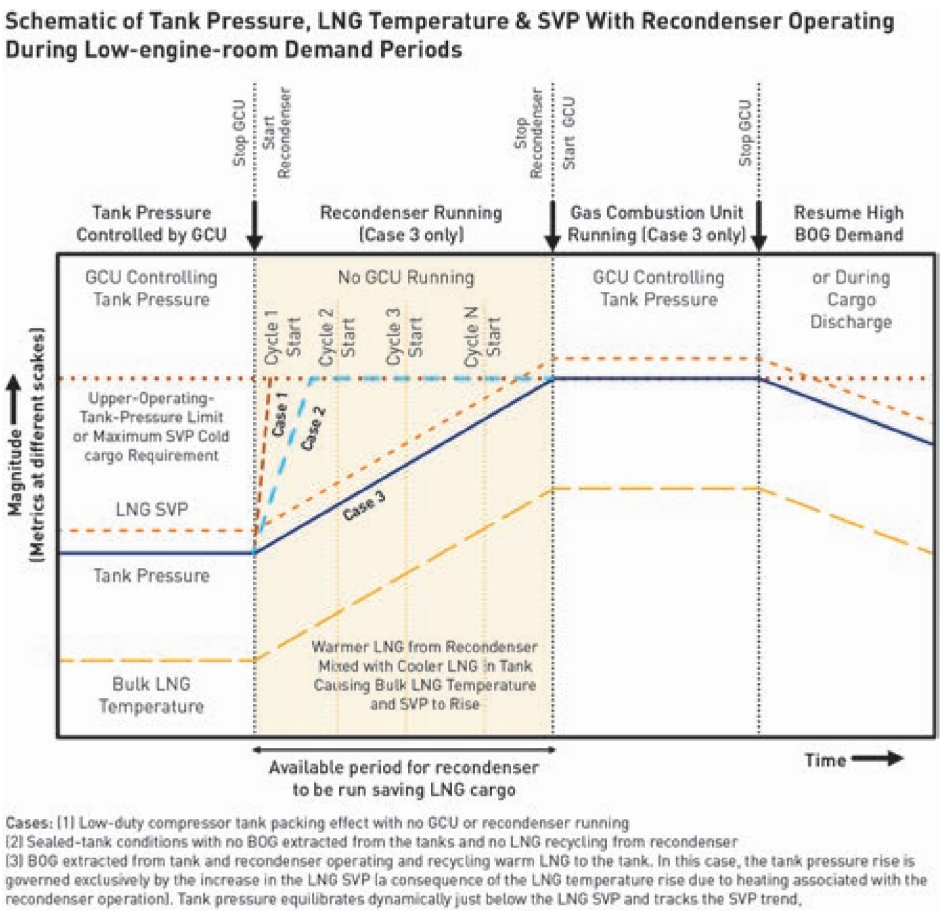


Figure 3: Schematic of LNGC tank pressure behaviour during three distinct situations on DFDE-powered LNGC experiencing low-fuel demand in the engine room

in order to minimize shipboard gas consumption in GCU.

Modern LNGC have cargo tanks rated with NBOR ranging from 0.08 to 0.15 % volume /day of full cargo (compared to about 0.05% for large, land-based, LNG storage tanks). An LNGC with 170,000 m3 cargo capacity including GTT membrane Mark V tanks (~0.08% NBOR) would experience natural heat ingress into those tanks equivalent to about 2.5 t/h of BOG.

A DFDE LNGC, at anchor, has engine room consumption of about 1 t/h, or less.

During port manoeuvring conducted at slow speeds, such vessels would also have low engine-room fuel demand (if any, as marine diesel fuel may be used instead of BOG for such operations). In such conditions, the tank pressure is likely to rise rapidly as the LDC recirculates the unrequired part of BOG back to the cargo tank.

This causes the tanks to be "packed" very rapidly with hot-BOG vapor returned to the fully loaded tanks, because the available vapor space in those tanks is small.

At tanks with NBOR of 0.15 % vol/day it becomes necessary for the vessel to handle BOG of 4.0 to 4.3 t/h, which would only be possible with the engines operating at full speed without operating the GCU/SD (Table 2 for results of low-engine room-fuel demand during transit).

A sub-optimized test on an FSRU (Kulitsa & Wood, 2017a) revealed that a recondenser running in full recirculation mode (with regasification/gas sendout interrupted) resulted in a tank-pressure rise of at about 4 mbar/hour (cargo tanks filled 70 to 80 % of full capacity).

Testing

Another test, with sealed tank conditions (i.e., no boil off extracted and 70% cargo in tank) resulted in a 15 mbar/hour tank pressure rise. In both tests the tanks were rated for NBOR of 0.15 % vol/day.

On a DFDE LNGC, some rare situations arise when essentially sealed tank conditions prevail, e.g., when the engines are only using marine diesel fuel and no BOG.

This may lead to tank pressure increases similar to those observed in the sealed tank test. However, sealed tank conditions occur infrequently for such reasons, because marine diesel fuel is at least 3 times more expensive than gas and using it extensively may cause commercial complications regarding a ship's contract of carriage or time charter.

Precautions necessary for operating recondensers in recirculation mode during laden voyages: The primary constraints in determining whether an LNGC recondenser could be used in prevailing circumstances, and for how long it could be used are:

1) the temperature of the LNG cargo and its related SVP (final at delivery port), which must be within limits determined by the receiving terminal on the cargoes day of arrival; and,

2) the LNGC's tank pressure must not exceed its upper-operating-tank-pressure limit (typically, 180-190 mbarg on tanks with 250 mbarg MARVS).

As either of these constraints is approached continued recondenser use ceases to be possible on an LNGC, which is likely to mean that the GCU/SD equipment has to be run to hold conditions close to their constraint limits.

Engine room BOG consumption plus GCU consumption of BOG need to approximate the NBOR of the LNGC in order for those constraint conditions to be maintained in a sustainable manner for significant periods of time.

Potential utilization of LNGC recondensers

For example, if there is a specific requirement to deliver the LNG cargo with an SVP not- higher-than 160 mbarg, then the recondenser may be used causing the tank pressure to increase to about 140 to 150 mbarg, and then replaced by the GCU/SD.

In some LNG receiving terminals there are no upper-limit requirements for LNG temperature or SVP and they are willing and able to accept cargoes with SVP of 180 to 200 mbarg.

Clearly, in the latter case the recondenser could be used for a longer period until it reached the tank-pressure-safety limits.

The period for which a recondenser could be used on an LNGC is conditional on operating conditions and the state (P, T and SVP) of the LNG cargo at the time.

When LNG is loaded in a cold state and marine conditions allow the ship to travel at high speeds (i.e., high BOG demand by the engine room) the cargo should achieve a stable state with SVP ranging between about 90 and110 mbarg, depending upon the composition of the LNG.

For lighter LNG grades (e.g. from Trinidad) stable SVP would be closer to 110mbarg, whereas for heavier LNG (e.g. from Nigeria) stable SVP would be closer to 90 mbarg.

With the cargo in such conditions, the LNGC could run its recondenser until tank pressures reached 170 to180 mbarg. Estimated duration of uninterrupted recondenser operation would then be up to about 20 to 24 hours, depending upon the LNG grade.

The short periods of recondenser operation would slightly improve the shipboard gas consumption performance of a DFDE LNGC.

STS transfers

A recondenser is also likely to improve BOG handling outcomes for LNGCs engaged in ship-to-ship (STS) transfer operations (LNGC to LNGC), complementing the most efficient STS transfer measures recommended for LNGCs without recondensers fitted.

This is because during STS transfers additional BOG is generated, a portion of which typically represents an additional contribution to gas consumed in the GCU /SD. Depending on cold-cargo delivery specifications, potentially the recondenser could be run for a significant portion of a STS transfer operation and thereby contribute to reducing total gas consumption in the GCU/SD. The recondenser (if located on the cargo-receiving vessel) would only be brought into operation when a significant amount of the LNG had been deposited on board (i.e., about one-third of the transferring cargo loaded).

Possible installation configurations for a compact recondenser on an LNG: Typical LNGC designs allow for an installation of a recondenser on the deck or in the cargo machinery room. The main equipment required for such an installation is the pipework connecting LNG feed (cooler LNG) to the recondenser from each cargo tank and facilitating the return of warm LNG to the bottom of each tank at the same or variable rates. The existing lines (pipework) on LNGC may be used to achieve this with minimum modifications (Figure 2) and cost but would require welding making dry-dock (alongside wharf) work likely.

The capacity of a LNGC recondenser for the use described can by small, i.e., large enough to decondense BOG quantities just in excess of the specified NBOG value for the particular ship, with some margin.

The recondenser would require about 10 to15 times more LNG feed forming its condensing fluid than the BOG supply. For a LNGC with 0.15 % vol NBOG the recondenser would need to be sized to handle about 4.3 t/h of BOG and 43 to 65 t/h (100 to150 m3/h) of LNG feed. Such small capacity is significantly below the minimum continuous flow of the main LNG cargo pumps on typical LNGC.

If the main cargo pumps are used to feed LNG to a small recondenser, that would lead to excessive in-tank

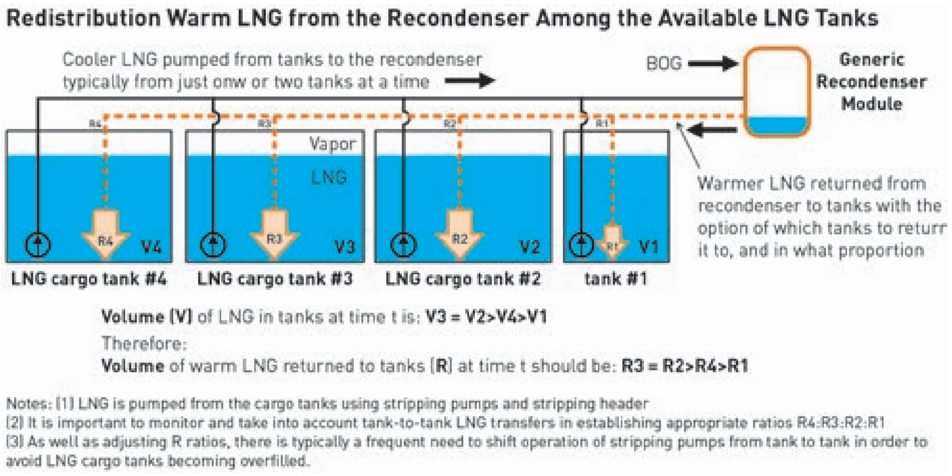


Figure 4: Optimal distribution of return LNG back to tank proportionally to LNG mass in tank

recirculation of the LNG causing more rapid heating of the LNG cargo, countering the positive benefits of running the recondenser. However, the LNG feed flows required by a small recondenser are within the capacity of the LNG stripping/spray pumps installed as standard in each LNGC cargo tank. Their typical capacity is 50 m3/h for an individual pump with a discharge pressure of about 5 to 6 barg at full flow (135 to145-meter liquid column at nominal discharge rate). That flow capacity size fits well with the LNG feed requirements of a small recondenser, with LNG being fed simultaneously from 2 to 4 tanks, thereby minimizing internally transferred LNG and reducing overfill risks due to recondenser operating.

Connecting LNG feed using the cargo tank stripping/spray pumps to the recondenser can be readily achieved using the existing spray/stripping header that connects all tanks. BOG supply can be readily configured (involving an add-on of branch piping to connect the recondenser with BOG feed) and controlled from the LDC to recondenser. The warm LNG return from the recondenser to all LNGC tanks would require the installation of a dedicated insulated line along all tanks with connections to the filling line (loading pipe) for each tank downstream of the tank filling valve, avoiding the need for new penetration entries into the tanks. Figure 2 illustrates this economical configuration for a recondenser on a LNGC. Simple manual globe valves could be used to control the LNG return flow to every tank.

Retrofitting recondensers on steam-powered LNGC is unlikely to be as beneficial as for DFDE LNGC for two main reasons: 1) an additional high-pressure compressor would need to be installed, in addition to the recondenser and pipework connections; and 2) they do not experience "packing" of the tank vapor space by an LDC that characterizes DFDE LNGC operations. At anchor, the consumption referred to as excess BOG on steam-powered LNGC is typically handled with use of the steam dump (i.e., the boiler burns more than necessary for the ships power requirements and excess of steam is dumped). Although SD consumption, like GCU consumption on DFDE vessels, is cargo burned with no positive benefit, it often conceals some of the excess BOG on steam-powered vessels. Detailed cost-benefit analyses are required to assess the commercial viability of retrofitting a recondenser on steam-powered LNGC to preserve some LNG cargo that would otherwise be lost via the steam dump.

Operational pattern for a recondenser on a LNGC: Figure 3 provides a schematic trends of tank pressure and cargo LNG temperature and SVP controlled by coordinated recondenser and GCU operations. In the case shown, an upper-operating-tank-pressure limit or maximum SVP limit applied by delivery terminal requirements determines the maximum pressures reached.

Achieving Maximum Operating Efficiency with a LNGC Recondenser: The period for which a recondenser can be run on a LNGC (which will always be in recirculation mode) is dependent on several factors, which influence the optimum recirculation period to minimize cargo loss. These are:

Cold Cargo Requirement or MARVS limits (Upper-operating-tank-pressure limit): A typical LNGC is rated at 250 mbarg MARVS (upper operating tank pressure limit 180 to 190 mbarg) which limits the possible use of the recondenser. That limit may be further constrained by the SVP requirements of the receiving terminal / customer contract (Figure 3).

Amount of LNG Liquid Onboard: Use of recondensers in cargo recirculation mode on LNGC are only viable on the laden voyage with a full or nearly full cargo onboard. Using a recondenser during the ballast voyage with a small LNG heel cargo would cause tank pressure to rise faster, countering any efficiency benefits.

Spreading Warm Return LNG Throughout the LNG Cargo Tanks: Spreading the return LNG to LNG tanks and dissipating it with the bulk LNG of those tanks occurs at a rate that is proportional to the LNG mass in the cargo tank. Consequently, tank #1 is the smallest one and it should receive, proportionally, the smallest LNG return. Fine turning of return flow to tanks can be adjusted by monitoring the LNG cargo temperatures in the tanks. Ideally, LNG temperatures should be approximately the same (0.1 to 0.2oC maximum difference for the typical LNGC with a single LNG grade onboard) in all cargo tanks. In order to prolong the duration of recondenser use, it is essential to spread and dissipate the warm return LNG effectively and simultaneously throughout all cargo tanks. Return flow operations should never exclude any tank from this process (without good reason) and return warm LNG should always be directed back to the bottom of the cargo tanks via the tank filling /loading lines and never sprayed into the tops of the tanks (Figure 4).

Amount of LNG Fed to Recondenser and its Impact: Cooler LNG fed to an LNGC recondenser needs to be tuned to the capacity capable of condensing the prevailing excess BOG, which will vary depending upon conditions. It is not appropriate to always use a constant or maximum LNG feed flow rate. As the total BOG flowing to the recondenser and engine room is required to be just above the NBOR rate, the recondenser flow can be tuned to balance engine room BOG consumption.

Excessive flow of total LNG to and from the recondenser will result in excessive recirculation and return more heat back to the tanks (despite the actual colder temperature of the return LNG).

By carefully tuning flow rates to and from the recondenser, an optimum flow rate can be identified at which tank pressure rises more slowly. This optimum flow rate will vary depending upon prevailing conditions, but generally it should be just enough to recondense the prevailing BOG.

A return LNG flow rate that is too slow will lead to incomplete recondensing of the vapor and/or liquid remaining in the pipe connections for a prolonged period of time, which would further increase its temperature due to greater heat ingress from the atmosphere through the pipe insulation. It is appropriate, in cases of low excess BOG, to trial higher LNG feed flow rates to establish whether that leads to tank pressure more slowly (i.e. real-time fine tuning of LNG flow rates through the condenser).

Internal (in-tank) recirculation of stripping pumps: Continuous running of all LNG stripping pumps to feed the recondenser is counterproductive and will result in some in-tank recirculation and should therefore be avoided. It is better to run fewer pumps rather than run pumps at rates that generate in-tank recirculation LNG without sending that LNG as feed to the recondenser.

Overfilling of LNG tanks due to internal transfer of cargo: When all tanks are feeding LNG to the recondenser with all stripping pumps operating flow of feed LNG will range from 80 m3/h to 200 m3/h of LNG.

However, LNG feed requirements of the recondenser will fluctuate from time to time. Consequently, during certain periods, fewer stripping pumps are required to operate to avoid excessive recirculation.

During those periods, internal transfer of LNG between tanks is inevitable as return LNG needs to spread out through all tanks at same time, irrespective of how many tanks are providing feed LNG to the recondenser.

Frequent shifting of tanks to provide feed LNG to a recondenser requires that the cargo operators are mindful of the risks of overfilling certain tanks (i.e., those receiving return flow, but not providing feed LNG to the recondenser), and avoid tanks filling beyond 97% to 98 % of their capacity.

Challenges posed by stratification and rollover in LNG tanks: Running a recondenser to recirculation LNG to LNGC cargo tanks does not, on its own, create stratification or rollover events in LNG tanks.

This is so, because LNG of a single grade (density / composition) is extracted from a tank, heated by pumps, pipework friction and the recondensation of BOG and then returned to a tank as warmer LNG of a lighter grade (density is significantly less than the density of the LNG originally extracted from the LNG cargo tank).

The BOG involved in the cycle is a methane-dominated gas (typically 95 to 98 % CH_4), and once that BOG is condensed against a feed LNG in the recondenser it transforms that LNG into a slightly lighter grade (i.e., with a slightly higher methane content and lower density than the LNG into which it is returned in the LNG cargo tank).

That sequence of actions is not what is required to create the stratification conditions in a LNG tank that would lead to rollover.

Returning warmer and lighter LNG to the bottom of a tank holding LNG of a uniform, denser composition will lead to rapid dissipation and mixing of those distinct LNG compositions to a uniform state. This is achieved naturally by in-tank convection and buoyancy force acting on lighter LNG fed into the bottom of the tank.

Running the GCU-Steam dump while a recondenser is recirculating LNG to the cargo tanks: Running a recondenser to recirculate LNG to the cargo tanks of an LNGC is conducted as an alternative to running the GCU/SD equipment, at least for a certain period. Thus, it is counterproductive to run both at same time (during laden voyage), as that poor practice would increase the GCU rate in order to prevent a tank pressure rise and would lead to even more gas consumption in the GCU.

If a recondenser is operated during a STS transfer, then it may be appropriate to run it in conjunction with the GCU/SD, to address the BOG impacts of typical STS-transfer-operating conditions (i.e., changing LNG volume and associated compression or "packing" and heating of the receiving tank's vapor space).

Combined running of the recondenser and GCU/SD should only involve intermittent running of the GCU/SD only when tank pressure approaches the upper-operating-tank-pressure limit. Operating in this way, the GCU/SD is applied only to limit the tank-pressure peak, which often occurs towards the end of an STS transfer when the tank pressure is located above the SVP of the LNG.

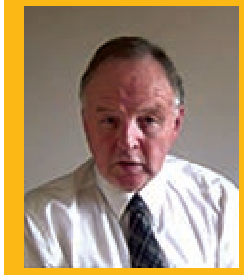
So, it remains counterproductive to run the GCU/SD concurrently with the recondenser for periods during a STS transfer when tank pressure is not at or near to its upper-operating-tank-pressure limit or its cold-cargo-requirement pressure.

Once LNG SVP has reached its cold-cargo-requirement pressure or its upper-operating-tank-pressure limit (due to prolonged operation of the recondenser) then the recondenser should be stopped and GCU engaged alone. ■

In next month's "LNG Journal" we will look at specific possible recondenser configuration for LNGC in Part II of "Exploitation of Recondensing Equipment on LNG Carriers to Minimize LNG Cargo Losses during Laden Sea Transport" by Maksym Kulitsa and David A. Wood.

About the Authors

Maksym Kulitsa is an independent FSRU consultant who has more than eight years of operating experience on different regasification systems and at various terminals. FSRUs are a relatively recent addition to the LNG industry and he has some expertise in optimizing or fine-tuning FSRU-related operations with regard to particular ship designs and operating conditions.



David A. Wood is the Principal Consultant of DWA Energy Limited (U.K.), specializing in the integration of technical, economic, fiscal, risk and strategic information to aid project planning and operating decisions. He has more than 35 years of international oil and gas experience, with companies including Phillips Petroleum and Amoco, spanning project operations, technical evaluations and senior management. .

World LNG Carrier Fleet

LNG carrier	Capacity m^3	Owned or Ordered by	Builder	Delivery Date	Flag	Power Plant	Cargo System	No. of tanks	Ship built for Export plant
Aamira	266,000	QGTC	Samsung	Dec-10	Liberia	DRL	TZ Mk. III	5	Qatargas IV
Abadi	135,000	Brunei Gas Carriers	Mitsubishi Nagasaki	Jun-02	Brunei	S	Moss	5	Brunei LNG
Abalamabie	174,900	Bonny Gas	Samsung	June-16	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
Adam LNG	162,000	Oman LNG	Hyundai	Dec-14	Marshall Is.	DFDE	TZ Mk. III	4	Oman LNG
Al Aamriya	210,100	J5 Consortium	Daewoo	Feb-08	Marshall Is.	DRL	GT NO 96	4	Qatargas
Al Areesh	151,700	Teekay LNG	Daewoo	Jan-07	Qatar	S	GT NO 96	4	Ras Gas II
Al Bahiya	266,000	QGTC	Samsung	Oct-09	Liberia	DRL	TZ Mk. III	5	Qatar-Atlantic
Al Biddah	135,275	J4 Consortium	Kawasaki Sakaide	Nov-99	Japan	S	Moss	5	Qatargas
Al Daayen	151,700	Teekay LNG	Daewoo	Apr-07	Qatar	S	GT NO 96	4	RasGas II
Al Dafna	266,000	QGTC	Samsung	Oct-09	Marshall Is.	LR DRL	GT NO 96	4	Qatar-Atlantic
Al Deebel	145,000	Peninsular LNG	Samsung	Dec-05	Bahamas	S	TZ Mk. III	4	Qatargas
Al Gattara	216,200	OSG/Nakilat	Hyundai	Oct-07	Marshall Is.	DRL	TZ Mk. III	4	Qatargas II
Al Ghariya	210,100	ProNav	Daewoo	Feb-08	Bahamas	DRL	GT No. 96	4	Qatargas
Al Gharaffa	216,200	OSG/Nakilat	Hyundai	Jan-08	Marshall Is.	DRL	TZ Mk. III	4	Various
Al Ghashamiya	216,000	QGTC	Samsung	Mar-09	Liberia	DRL	TZ Mk. III	4	Qatar-Atlantic Basin
Al Ghuwairiya	261,700	QGTC	Daewoo	Aug-08	Marshall Is.	DRL	GT NO. 96	5	Qatar-Atl'c Basin
Al Hamla	216,000	OSG	Samsung	Feb-08	Marshall Is.	DRL	TZ Mk. III	4	QatarGas
Al Hamra	137,000	National Gas Shipping	Kvaerner-Masa	Jan-97	Liberia	S	Moss	4	ADGAS
Al Huwaila	217,000	Teekay	Samsung	May-08	Bahamas	DRL	TZ Mk. III	4	RasGas III
Al Jasra	137,100	J4 Consortium	Mitsubishi Nagasaki	Jul-00	Japan	S	Moss	5	Qatargas
Al Jassasiya	145,700	Maran-Nakilat	Daewoo	May-07	Greece	S	GT No 96	4	RasGas
Al Kharaitiyat	216,200	QGTC	Hyundai	May-09	Liberia	DRL	TZ Mk. III	4	Qatargas III
Al Kharaana	210,000	QGTC	Daewoo	Oct-09	Marshall Is.	DRL	GT NO 96	4	Qatargas IV
Al Kharsaah	217,000	Teekay	Samsung	May-08	Bahamas	DRL	TZ Mk. III	4	RasGas III
Al Khattiya	210,000	QGTC	DSME	Oct-09	Marshall Is.	DRL	GT No. 96	4	Qatargas IV
Al Khaznah	135,500	National Gas Shipping	Mitsui Chiba	Jun-94	Liberia	S	Moss	5	ADGAS
Al Khor	137,350	J4 Consortium	Mitsubishi Nagasaki	Dec-96	Japan	S	Moss	5	Qatargas
Al Khuwair	217,000	Teekay LNG	Samsung	Jul-08	Korea	DRL	TZ Mk. III	4	RasGas
Al Mafyar	266,000	OSG/Nakilat	Hyundai	Oct-07	Marshall Is.	DRL	TZ Mk. III	4	Qatargas II
Al Marrouna	151,700	Teekay	Daewoo	Nov-07	Bahamas	S	GT NO 96		Ras Gas I
Al Mayeda	266,000	QGTC	Samsung	Jan-09	Liberia	DRL	TZ Mk. III	5	Qatar-US/Var.
Al Nuaman	210,000	QGTC	DSME	Dec-09	Marshall Is.	DRL	GT No. 96	4	Qatargas IV
Al Oraiq	210,000	J5 Consortium	Daewoo	Apr-08	Marshall Is.	DRL	GT No. 96	4	Various
Al Rayyan	135,360	J4 Consortium	Kawasaki Sakaide	Mar-97	Japan	S	Moss	5	Qatargas
Al Rekayyat	216,200	QGTC	Hyundai	Jun-09	Bahamas	DRL	TZ Mk.III	4	Qatar-Atlantic
Al Ruwais	210,100	ProNav	Daewoo	Nov-07	Germany	DRL	GT NO 96	4	Qatargas II
Al Sadd	210,100	QGTC	Daewoo	Mar-09	Liberia	DRL	GT NO 96	4	Qatar-Atlantic Basin
Al Safliya	210,100	ProNav	Daewoo	Dec-07	Bahamas	DRL	GT NO 96	4	Qatargas II
Al Sahla	216,200	J5	Hyundai	Jun-08	Japan	DRL	TZ Mk. III	4	Ras Gas III
Al Samriya	261,700	QGTC	Daewoo	Sep-08	Marshall Is.	DRL	GT NO. 96	5	Qatargas II
Al Sheehaniya	210,100	QGTC	Daewoo	Feb-09	Liberia	DRL	GT NO 96	4	Qatar-Atlantic Basin
Al Shamal	217,000	Teekay LNG	Samsung	Jun-08	Qatar	DRL	TZ Mk. III	4	RasGas
Al Thakhira	145,000	Peninsular LNG	Samsung	Sep-05	Bahamas	S	TZ Mk. III	4	Qatargas
Al Thumama	216,000	J5 Consortium	Hyundai	Apr-08	Japan	DRL	TZ Mk. III	4	Rasgas
Al Utouriya	215,000	J5	Hyundai	Sep-08	Panama	DRL	TZ Mk. III	4	RasGas
Al Utourma	215,000	J5	Hyundai	Sep-08	Panama	DRL	TZ Mk. III	4	Ras Gas III
Al Wajbah	137,350	J4 Consortium	Mitsubishi Nagasaki	Jun-97	Japan	S	Moss	5	Qatargas
Al Wakrah	135,360	J4 Consortium	Kawasaki Sakaide	Dec-98	Japan	S	Moss	5	Qatargas
Al Zhubarah	137,570	J4 Consortium	Mitsui Chiba	Dec-96	Japan	S	Moss	5	Qatargas
Alto Acrux	147,000	LNG Marine Transport	Mitsubishi	Mar-08	Bahamas	S	Moss	4	Various
Amali	148,000	Brunei-Shell	DSME	Jul-11	Brunei	DFDE	GT No. 96	4	Brunei LNG
Amanl	154,800	Brunei-Shell	Hyundai	Nov-14	Brunei	DFDE	TZ Mk. III	4	Brunei LNG
Aman Bintulu	18,928	Perbadanan / NYK Line	NKK Tsu	Oct-93	Malaysia	S	TZ Mk. III	3	Petronas
Aman Hakata	18,800	Perbadanan / NYK Line	NKK Tsu	Nov-98	Malaysia	S	TZ Mk. III	3	Petronas
Aman Sendai	18,928	Perbadanan / NYK Line	NKK Tsu	May-97	Malaysia	S	TZ Mk. III	3	Petronas
Arctic Aurora	160,000	Dynagas	Hyundai	Jul-13	Marshall Is.	DFDE	TZ Mk. III	4	Various
Arctic Discoverer	140,000	K Line	Mitsui Chiba	Jan-06	Bahamas	S	Moss	4	Various
Arctic Lady	147,200	MOL/Hoegh LNG	Mitsubishi Nagasaki	Apr-86	Norway	S	Moss	4	Various
Arctic Princess	147,200	MOL/Hoegh LNG	Mitsubishi Nagasaki	Jan-06	Norway	S	Moss	4	Various
Arctic Sun	89,880	Arctic LNG Shipping	IHI Chita	Dec-93	Liberia	S	IHI SPB	4	ConocoPhillips/Marathon
Arctic Voyager	140,000	K Line	Kawasaki	Jul-06	Bahamas	S	Moss	4	Statoil
Arkat	148,000	Brunei-Shell	DSME	Feb-11	Brunei	DFDE	GT. No. 96	4	Brunei LNG
Arwa Spirit	165,000	Teekay LNG	Samsung	Sep-08	Marshall Is.	DFDE	TZ Mk. III	4	Various
Aseem	154,850	K Line-Petronet	Samsung	Nov-09	Malta	S	GT No 96	4	Qatar-India
Asia Endeavour	160,000	Chevron	Samsung	Dec-14	Bahamas	DFDE	TZ Mk. III	4	Various
Asia Energy	160,000	Chevron	Samsung	Sept-14	Bahamas	DFDE	TZ Mk. III	4	Various
Asia Excellence	160,000	Chevron	Samsung	Sept-13	Bahamas	DFDE	TZ Mk. III	4	Various
Asia Venture	160,000	Chevron	Samsung	Sept-17	Bahamas	DFDE	TZ Mk. III	4	Various
Asia Vision	160,000	Chevron	Samsung	June-14	Bahamas	DFDE	TZ Mk. III	4	Various
Barcelona Knutsen	173,400	Knutsen	Daewoo	May-10	N.I.S.	DFDE	GT NO 96	4	Various
Bebatic	75,060	Brunei Shell Tankers	Atlantique	Oct-72	Brunei	S	TZ Mk. I	6	Brunei LNG
Beidou Star	172,000	MOL	Hudong	Oct-15	Hong Kong	DRL	GT NO. 96	4	Various
Berge Arzew	138,088	BW Gas	Daewoo	Jul-04	Norway	S	GT NO 96	4	Sonatrach
BW GDF-Suez Boston	138,059	BW Gas	Daewoo	Jan-03	Norway	S	GT NO 96	4	Suez LN
BW GDF Suez Everett	138,028	BW Gas	Daewoo	Jun-03	Norway	S	GT NO 96	4	Suez LNG
BW Integrity	170,000	BW Gas	Samsung	May-17	Singapore	DFDE	TZ Mk. III	4	FSRU
BW Pavilion Leeara	161,880	BW Gas	Hyundai	Feb-15	Singapore	DFDE	TZ Mk. III	4	Various
BW Pavilion Vanda	161,880	BW Gas	Hyundai	Feb-15	Singapore	DFDE	TZ Mk. III	4	Various
BW Singapore	170 000	BW Gas	Samsung	May-15	Singapore	DFDE	TZ Mk. III	4	FSRU
BW Suez Paris	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GT NO 96	4	Yemen-Atlantic
Bilbao Knutsen	138,000	Knutsen / Marpetrol	IZAR Sestao	Jan-04	Spain	S	GT NO 96	4	Atlantic LNG
Bilis	77,730	Brunei Shell Tankers	La Seyne	Mar-75	Brunei	S	GT NO 82	5	Brunei LNG
Bishu Maru	162,000	K Line-Transpacific	Kawasaki Sakaide	Dec-15	Panama	S	Moss	4	Australia-Japan
British Diamond	155,000	BP Shipping	Hyundai	Sep-08	IOM	DFDE	TZ Mk. II	4	Indonesia-Various
British Emerald	155,000	BP Shipping	Hyundai	Jun-07	UK	DFDE	TZ Mk. III	4	Tangguh LNG
British Innovator	138,200	BP Shipping	Samsung	Jul-03	Isle of Man	S	TZ Mk. III	4	Various
British Merchant	138,000	BP Shipping	Samsung	Apr-03	Isle of Man	S	TZ Mk. III	4	Various

British Ruby	155,000	BP Shipping	Hyundai	Jan-08	U.K.	DFDE	TZ Mk. III	4	Various
British Sapphire	155,000	BP Shipping	Hyundai	Sep-08	IOM	DFDE	TZ Mk. III	4	Tangguh
British Trader	138,000	BP Shipping	Samsung	Dec-02	Isle of Man	S	TZ Mk. III	4	Engas
Broog	135,466	J4 Consortium	Mitsui Chiba	May-98	Japan	S	Moss	5	Qatargas
Bu Samara	266,000	QGTC	Samsung	Dec-08	Qatar	DRL	TZ Mk. III	5	Qatargas
BW Suez Paris	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GT NO 96	4	Yemen-Atlantic
BW Suez Brussels	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GT NO 96	4	Yemen-Atlantic
Cadiz Knutsen	138,826	Knutsen / Marpetrol	IZAR Puerto Real	Jun-04	Spain	S	GT NO 96	4	Engas
Castillo de Santisteban	173,600	Elcano	STX	Aug-10	Malta	S	GT NO. 96		Various
Castillo de Villalba	138,000	Elcano	IZAR	Nov-03	Spain	S	GT NO 96	4	Sonatrach
Catalunya Spirit	138,000	Teekay LNG Partners	IZAR Sestao	Mar-03	Liberia	S	GT NO 96	4	Atlantic LNG
Celestine River	145,000	KLNG	Kawasaki	Dec-07	Bahamas	S	Moss		Various
Cesi Beihai	174,100	MOL-China LNG	Hudong	June-17	Hong Kong	S	GT No 96	4	Australia-China
Cesi Gladstone	174,100	MOL-China LNG	Hudong	Oct-16	Hong Kong	S	GT No 96	4	Australia-China
Cesi Qingdao	174,100	MOL-China LNG	Hudong	Nov-16	Hong Kong	S	GT No 96	4	Australia-China
Cesi Tianjin	174,100	MOL-China LNG	Hudong	Sept-17	Hong Kong	S	GT No 96	4	Australia-China
Cheikh Bouamama	75,500	Skikda LNG Transport	USC	Jul-08	Bahamas	S	TZ Mk. III	4	Sonatrach
Cheikh El Mokrani	75,500	Med LNG Corp	USC	Jun-07	Bahamas	S	TZ Mk. III	4	Sonatrach
Christophe de Margerie	172,600	SCF	Daewoo	Nov-16	Cyprus	DFDE	GT NO 96	4	Various
Clean Energy	150,000	Dynagas	Hyundai	Mar-07	Marshall Is.	S	TZ Mk. III	4	Various
Clean Force	150,000	Dynagas	Hyundai	Jan-08	Marshall Is.	S	TZ Mk. III	4	Various
Clean Ocean	155,900	Dynagas	Hyundai	Mar-14	Marshall Is.	DFDE	TZ Mk. III	4	Various
Clean Planet	155,900	Dynagas	Hyundai	Mar-14	Marshall Is.	DFDE	TZ Mk. III	4	Various
Clean Vision	160,000	Dynagas	Hyundai	Jun-15	Marshall Is.	DFDE	TZ Mk. III	4	Various
Cool Explorer	160,000	Thenamaris	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Cool Runner	160,000	Thenamaris	Samsung	May-14	Bermuda	DFDE	TZ Mk. III	4	Various
Cool Voyager	160,000	Thenamaris	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Corcovado LNG	160,106	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GT No 96	4	Various
Creole Spirit	174,000	Teekay	Daewoo	Jan-16	Bahamas	MEGI-DF	NO. 96 GW	4	Cheniere
Cubal	160,400	Mitsui/NYK/Teekay	Samsung	Jan-12	Bahamas	DFDE	TZ Mk. III	4	Various
Cygnus Passage	145,400	Cygnus LNG	Mitsubishi	Feb-09	Panama	S	Moss	4	Various
Dapeng Moon	147,000	China Ships	Hudong	Jul-09	China	S	GT NO 96	4	Various
Dapeng Star	147,000	China Ships	Hudong	Nov-09	China	S	GT NO 96	4	Various
Dapeng Sun	147,000	China Ships	Hudong	Jul-07	China	S	GT NO 96	4	Woodside Energy
Disha	136,000	Petronet LNG Ltd.	Daewoo	Jan-04	Malta	S	GT NO 96	4	Qatargas
Doha	137,350	J4 Consortium	Mitsubishi Nagasaki	Jun-99	Japan	S	Moss	5	Qatargas
Duhail	210,100	ProNav	Daewoo	Jan-08	Germany	DRL	GT NO 96	4	Various
Dukhan	135,000	J4 Consortium	Mitsui Chiba	Oct-04	Japan	S	Moss	4	Qatargas
Dwiputra	127,385	Humpuss Consortium	Mitsubishi Nagasaki	Mar-94	Bahamas	S	Moss	4	Pertamina
Ebisu	147,547	Golar LNG	Kawasaki	Sep-08	Bahamas	S	Moss	4	Various
Ejnan	145,000	4J	Samsung	Jan-07	Bahamas	S	TZ Mk. III		RasGas
Ekaputra	136,400	Humpuss Consortium	Mitsubishi Nagasaki	Jan-90	Liberia	S	Moss	5	Pertamina
Energy Advance	145,000	Tokyo LNG Tankers	Kawasaki Sakaide	Mar-05	Japan	S	Moss	4	Darwin
Energy Atlantic	159,924	Alpha	STX Jinhae	Sep-15	Malta	DFDE	No. 96	4	Various
Energy Confidence	155,000	Tokyo LNG Tankers	Kawasaki	Apr-09	Panama	S	Moss	4	Various
Energy Frontier	147,600	Tokyo LNG Tankers	Kawasaki Sakaide	Sep-03	Japan	S	Moss	4	Darwin
Energy Horizon	177,000	Tokyo LNG Tankers	Kawasaki	Jul-11	Japan	S	Moss	4	Pluto LNG
Energy Navigator	147,000	Tokyo LNG Tankers	Kawasaki Sakaide	May-08	Japan	S	Moss	4	Various
Energy Progress	145,000	MOL	Kawasaki	Nov-06	Japan	S	Moss	4	Bayu Undan LNG
Esshu Maru	162,000	K Line-Transpacific	Kawasaki Sakaide	Dec-14	Panama	S	Moss	4	Australia-Japan
Excalibur	138,200	Exmar/ Excelerate	Daewoo	Oct-02	Belgium	S	GT NO 96	4	Various
Excel	138,106	Exmar/ MOL	Daewoo	Sep-03	Belgium	S	GT NO 96	4	Various
Excelerate	138,000	Exmar/Excelerate	Daewoo	Oct-06	Belgium	S	GT NO 96	4	Various
Excellence	138,000	GKFF Ltd.	Daewoo	May-05	Belgium	S	GT NO 96	4	Excelerate Energy
Excelsior	138,000	Exmar	Daewoo	Jan-05	Belgium	S	GT NO 96	4	Various
Exemplar	150,900	Excelerate	Daewoo	Jun-10	Belgium	S	GT NO 96	4	Various
Expedient	151,000	Excelerate	Daewoo	Nov-09	Belgium	S	GT NO 96	4	Various
Experience RV	174,000	Exmar/Excelerate	Daewoo	Jul-14	Marshall Is.	DFDE	GT NO 96		Various
Explorer	150,900	Exmar/Excelerate	Daewoo	Mar-08	Belgium	S	GT NO 96	4	Excelerate
Express	151,000	Exmar/Excelerate	Daewoo	May-09	Belgium	S	GT NO 96	4	Various
Exquisite	150,900	Excelerate	Daewoo	Sep-09	Belgium	S	GT NO 96	4	Various
Flex Endeavour	173,400	Flex LNG	Daewoo	Jan-18	Marshall Is.	MEGI-DF	NO. 96 GW	4	Various
Flex Enterprise	173,400	Flex LNG	Daewoo	Jan-18	Marshall Is.	MEGI-DF	NO. 96 GW	4	Various
Fraiha	210,100	J5 Consortium	Daewoo	Sep-08	Marshall Is.	DRL	GT NO 96	4	Qatargas
FSRU Independence	170,000	Hoegh	Hyundai	Feb-14	NIS	DFDE	TZ Mk. III	4	Various
FSRU Lampung	170,000	Hoegh	Hyundai	May-14	Indonesia	DFDE	TZ Mk. III	4	Various
Fuji LNG	147,895	TMSC Gas	Kawasaki	Jun-04	Malta	S	Moss	4	Various
Fuwairit	138,000	Peninsular LNG	Samsung	Jan-04	Bahamas	S	TZ Mk. III	4	RasGas II
Galea	134,425	Shell Shipping	Mitsubishi Nagasaki	Oct-02	Singapore	S	Moss	5	Shell
Galicia Spirit	140,620	Teekay LNG Partners	Daewoo	Jul-04	Liberia	S	GT NO 96	4	Engas
Gaselys	153,500	GdF/NYK	Atlantique	Mar-07	France	DFDE	CS 1	4	Engas
Gallina	134,425	Shell Shipping	Mitsubishi Nagasaki	Oct-02	Singapore	S	Moss	5	Shell
GasLog Chelsea	153,000	GasLog	Hanjin Korea	Dec-09	Panama	TFDE	TZ Mk. III	4	Various
Gaslog Geneva	174,000	GasLog	Samsung	Sept-16	Bermuda	TFDE	TZ Mk. III	4	Shell charter
Gaslog Gibraltar	174,000	GasLog	Samsung	Oct-16	Bermuda	TFDE	TZ Mk. III	4	Shell charter
Gaslog Glasgow	174,000	GasLog	Samsung	Jun-16	Bermuda	TFDE	TZ Mk. III	4	Shell charter
Gaslog Greece	174,000	GasLog	Samsung	Mar-16	Bermuda	TFDE	TZ Mk. III	4	Shell charter
GasLog Salem	165,000	GasLog	Samsung	Apr-15	Liberia	TFDE	TZ Mk. III	4	various
GasLog Santiago	155,000	GasLog	Samsung	Mar-13	Liberia	TFDE	TZ Mk. III	4	Various
GasLog Saratoga	155,000	GasLog	Samsung	Dec-14	Bermuda	TFDE	TZ Mk. III	4	Various
Gaslog Savannah	155,000	GasLog	Samsung	May-10	Bermuda	DFDE	TZ Mk. III	4	Various
GasLog Seattle	155,000	GasLog	Samsung	Oct-13	Bermuda	TFDE	TZ Mk. III	4	Various
GasLog Shanghai	155,000	GasLog	Samsung	Jan-13	Liberia	TFDE	TZ Mk. III	4	Various
Gaslog Singapore	155,000	GasLog	Samsung	Jul-10	Bermuda	DFDE	TZ Mk. III	4	Various
Gaslog Skagen	155,000	GasLog	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Gaslog Sydney	155,000	GasLog	Samsung	May-13	Bermuda	DFDE	TZ Mk. III	4	Various
GDF-Suez Global Energy	74,000	Gaz de France	Chantiers	Dec-06	France	DFDE	CS1	4	Sonatrach
GDF-Suez Cape Ann	145,000	Hoegh LNG/MOL	Samsung	May-10	Liberia	DFDE	TZ Mk. III	4	Various
GDF-Suez Neptune	145,000	Hoegh LNG/MOL	Samsung	Dec-09	Liberia	DFDE	TZ Mk. III	4	Various
GDF-Suez Point Fortin	154,200	LNG Japan	Imabari/Koyo	Feb-10	Panama	DFDE	TZ Mk. III	4	Various
Gemmata	138,100	Shell Shipping	Mitsubishi Nagasaki	Mar-04	Singapore	S	Moss	5	Shell
Ghasha	137,510	National Gas Shipping	Mitsui	Jun-95	Liberia	S	Moss	5	ADGAS

Gigira Laitebo	177,000	MOL-Itochu	Hyundai	Feb-09	Panama	DFDE	TZ Mk. III	4	Various
Golar Arctic	140,645	Golar LNG	Daewoo	Dec-03	Marshall Is.	S	GT NO 96	4	Shell Spot
Golar Bear	160,000	Golar	Samsung	Mar-14	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Celsius	160,000	Golar LNG	Samsung	Sep-13	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Crystal	160,000	Golar LNG	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Eskimo (FSRU)	160,000	Golar LNG	Samsung	Jan-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Freeze	125,850	Golar LNG	HDW	Feb-77	UK	S	Moss	5	Various
Golar Glacier	162,000	Golar LNG	Hyundai	Sep-14	Marshall Is.	DFDE	TZ Mk. III	4	Various
Golar Grand	145,880	Golar LNG	Daewoo	2006	IoM		GT NO 96	4	Various
Golar Ice	160,000	Golar LNG	Samsung	Feb-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Igloo (FSRU)	160,000	Golar LNG	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Kelvin	160,000	Golar LNG	Samsung	Jan-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Maria	145,950	Golar LNG	Daewoo	2006	Marshall Is.		GT NO 96	4	Various
Golar Mazo	135,225	Golar LNG/CPP	Mitsubishi	Jan-00	Liberia	S	Moss	5	Pertamina
Golar Penguin	160,000	Golar LNG	Samsung	Mar-14	Marshall Is.	DFDE	TZ Mk. III	4	Various
Golar Seal	160,000	Golar LNG	Samsung	Aug-13	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Singapore (FSRU)	160,000	Golar LNG	Samsung	June-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Snow	160,000	Golar LNG	Samsung	Jan-15	Bermuda	DFDE	TZ Mk. III	4	various
Golar Tundra (FSRU)	160,000	Golar LNG	Samsung	Dec-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Viking	140,000	Golar LNG	Hyundai	Jan-05	Marshall Is.	S	Moss	4	Various
Golar Winter	138,250	Golar LNG	Daewoo	Apr-04	Marshall Is.	S	GT NO 96	4	Petrobras
Grace Acacia	150,000	Algaet Shipping	Hyundai	Jan-07	Japan	S	TK MK III	4	Various
Grace Barleria	150,000	Swallowtail Ship	Hyundai	Oct-07	Japan	S	TZ Mk. III	4	Various
Grace Cosmos	150,000	AGH Shipping	Hyundai	Mar-08	Japan	S	TZ Mk. III	4	Various
Grace Dahlia	177,000	Tokyo Gas	Kawasaki	Oct-13	Japan	S	Moss	4	Various
Gracilis	138,830	Golar LNG	Hyundai	Jan-05	Marshall Is.	S	TZ Mk III	4	Shell BG
Granatina	140,645	Shell Shipping	Daewoo	Dec-03	Singapore	S	GT NO 96	4	Shell
Grand Aniva	147,200	Sovcomflot/NYK	Mitsubishi	Jan-08	Japan	S	Moss	4	Various
Grand Elena	147,200	Sovcomflot/NYK	Mitsubishi	Oct-07	Japan	S	Moss	4	Various
Grand Mereya	147,200	Primorsk/MOL/K Line	Chiba	May-08	Japan	S	Moss	4	Sakhalin II
Hanjin Muscat	138,200	Hanjin Shipping	Hanjin	Jul-99	Panama	S	GT NO 96	4	Oman Gas
Hanjin Pyeong Taek	130,600	Hanjin Shipping	Hanjin	Sep-95	Panama	S	GT NO 96	4	Pertamina
Hanjin Ras Laffan	138,214	Hanjin Shipping	Hanjin	Jul-00	Panama	S	GT NO 96	4	QatarGas
Hanjin Sur	138,333	Hanjin Shipping	Hanjin	Jan-00	Panama	S	GT NO 96	4	Oman Gas
Hispania Spirit	140,500	Teekay LNG Partners	Daewoo	Sep-02	Spain	S	GT NO 96	4	Atlantic LNG
Hoegh Gallant FSRU	170,050	Hoegh LNG	Hyundai	May-14	Marshall Is.	DFDE	TZ Mk. III	4	chartered
Hoegh Giant FSRU	170,050	Hoegh LNG	Hyundai	Jan-18	Marshall Is.	DFDE	TZ Mk. III	4	various
Hoegh Grace FSRU	170,050	Hoegh LNG	Hyundai	May-15	Marshall Is.	DFDE	TZ Mk. III	4	various
Hyundai Aquapia	135,000	Hyundai MM	Hyundai	Mar-00	Panama	S	Moss	4	Oman Gas
Hyundai	135,000	Hyundai MM	Hyundai	Jan-00	Panama	S	Moss	4	RasGas
Hyundai Ecopia	145,000	Hyundai	Hyundai	Nov-08	Panama	S	TZ Mk. III	4	Various
Hyundai Greenpia	125,000	Hyundai MM	Hyundai	Nov-96	Panama	S	Moss	4	Pertamina
Hyundai Oceanpia	135,000	Hyundai MM	Hyundai	Jul-00	Panama	S	Moss	4	Oman Gas
Hyundai Technopia	135,000	Hyundai MM	Hyundai	Jul-00	Panama	S	Moss	4	RasGas
Hyundai Utopia	125,182	Hyundai MM	Hyundai	Jun-94	Panama	S	Moss	4	Pertamina
Iberica Knutsen	138,000	Knutsen OAS	Daewoo	Aug-06	Norway	S	GT 96	4	Gas Natural
Ibra LNG	147,100	Oman Gas	Samsung	Jun-06	Panama	S	TK Mk. III	4	Oman LNG
Ibri LNG	145,000	Oman Gas	Mitsubishi	Jul-06	Panama	S	TK Mk. III	4	Oman LNG
Ish	137,540	National Gas Shipping	Mitsubishi Nagasaki	Nov-95	Liberia	S	Moss	5	ADGAS
K Acacia	138,017	Korea Line	Daewoo	Jan-00	Panama	S	GT NO 96	4	Oman Gas
K Freesia	135,256	Korea Line	Daewoo	Jun-00	Panama	S	GT NO 96	4	RasGas
K Jasmine	145,700	Korea Line	Daewoo	Mar-08	Panama	S	GT NO 96	4	Kogas offtake
K Mugungwha	152,000	K Line	Daewoo	Nov-08	Panama	S	GT NO 96	4	Various
Kita LNG	160,106	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GT No 96	4	Various
Kotawaka Maru	125,200	J3 Consortium	Kawasaki Sakaide	Jan-84	Japan	S	Moss	5	Darwin
Kumul	172,000	MOL	Hudong	May-16	Hong Kong	DRL	GT NO. 96	4	PNG-Asia
Lala Fatma N'Soumer	145,000	Algeria Nippon Gas	Kawasaki Sakaide	Dec-04	Japan	S	Moss	4	Sonatrach
Larbi Ben M'Hidi	129,750	SNTM-Hyproc	La Seyne	Jun-77	Algeria	S	GT NO 85	5	Sonatrach
Lijmilya	261,700	QGTC	Daewoo	Sep-08	Marshall Is.	DRL	GT NO. 96	5	Various
LNG Abalamabie	174 900	Bonny Gas	Samsung	Nov-16	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Abuja	126,530	Bonny Gas Transport	GD Quincy	Sep-80	Bahamas	S	Moss	5	Nigeria LNG
LNG Abuja II	174 900	Bonny Gas	Samsung	Oct 16	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Adamawa	141,000	Bonny Gas Transport	Hyundai	Jun-05	Bermuda	S	Moss	4	Various
LNG Akwa Ibom	141,000	Bonny Gas Transport	Hyundai	Nov-04	Bermuda	S	Moss	4	Various
LNG Aquarius	126,300	MOL/LNG Japan	GD Quincy	Jun-77	Marshall Is.	S	Moss	5	Various
LNG Barka	153,000	NYK	Kawasaki	Jan-09	Bahamas	S	Moss	4	Various
LNG Bayelsa	137,500	Bonny Gas Transport	Hyundai	Feb-03	Bermuda	S	Moss	4	Nigeria LNG
LNG Benue	145,700	BW Gas	Daewoo	Mar-06	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Bonny	177,000	Bonny Gas Transport	Hyundai	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Borno	149,600	NYK Line	Samsung	Aug-07	Japan	S	TZ Mk. III	4	Nigeria LNG
LNG Capricorn	126,300	MOL/LNG Japan	GD Quincy	Jun-78	Marshall Is.	S	Moss	5	Pertamina
LNG Cross River	141,000	Bonny Gas Transport	Hyundai	Sep-05	Bermuda	S	Moss	4	Various
LNG Dream	145,000	Osaka Gas	Kawasaki	Sep-06	Japan	S	Moss	4	Woodside Energy
LNG Ebisu	147,500	MOL	Kawasaki	Sep-08	Bahamas	S	Moss	4	Various
LNG Edo	126,530	Bonny Gas Transport	GD Quincy	May-80	Bahamas	S	Moss	5	Nigeria LNG
LNG Enugu	145,000	BW Gas	Daewoo	Oct-05	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Fimina	175,000	Bonny Gas Transport	Samsung	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Flora	127,700	J3 Consortium	Kawasaki Sakaide	Mar-93	Japan	S	Moss	4	Pertamina
LNG Fukurokuju	165,000	MOL	Kawasaki	June-15	Japan	S	Moss	4	Various
LNG Gemini	126,300	MOL/LNG Japan	GD Quincy	Sep-78	Marshall Is.	S	Moss	5	Pertamina
LNG Imo	148,300	BW Gas	Daewoo	Jun-08	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Jamal	135,330	Osaka Gas/J3 Consortium	Mitsubishi Nagasaki	Oct-00	Japan	S	Moss	5	Oman Gas
LNG Jupiter	145,000	NYK Line	Kawasaki	Jul-09	Bahamas	S	Moss	4	Various
LNG Jurojin	155,300	MOL	MHI Nagasaki	Nov-15	Japan	S	KM	4	Various
LNG Kano	148,471	BW Gas	Daewoo	Jan-07	Bermuda	S	GT No. 96	4	NLNG
LNG Lagos	177,000	Bonny Gas	Hyundai	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Leo	126,400	MOL/LNG Japan	GD Quincy	Dec-78	Marshall Is.	S	Moss	5	Pertamina
LNG Lerici	65,000	Exmar	Italcantieri Sestri	Mar-98	Italy	S	GT NO 96	4	Sonatrach
LNG Libra	126,400	Hoegh LNG	GD Quincy	Apr-79	Marshall Is.	S	Moss	5	Various
LNG Lokoja	148,300	BW Gas	Daewoo	Dec-06	Bermuda	S	GT No. 96	4	Nigeria LNG
LNG Mars	155,000	MOL/Osaka Gas	Mitsubishi	Oct-16	Marshall Is.	S	Moss	5	Various
LNG Ogun	148,300	NYK Line	Samsung	Aug-07	Japan	S	TZ Mk. III	4	Nigeria LNG
LNG Ondo	148,300	BW Gas	Daewoo	Sep-07	Bermuda	S	GT NO 96	4	Nigeria LNG

LNG Oyo	140,500	BW Gas	Daewoo	Dec-05	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Pioneer	138,000	MOL	Daewoo	Jul-05	Bahamas	S	GT No 96	4	Idku
LNG Port Harcourt	175,000	Bonny Gas	Samsung	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Portovenere	65,000	Exmar	Italcantieri Sestri	Jun-96	Italy	S	GT No 96	4	Sonatrach
LNG River Niger	141,000	Bonny Gas Transport	Hyundai	May-06	Bermuda	S	Moss	4	Various
LNG River Orashi	145,910	BW Gas	Daewoo	Nov-04	Bermuda	S	GT No 96	4	Nigeria LNG
LNG Rivers	137,231	Bonny Gas Transport	Hyundai	Jun-02	Bermuda	S	Moss	4	Nigeria LNG
LNG Saturn	153,000	MOL	MHI	Nov-15	Japan	S	Moss	4	Various
LNG Sokoto	137,231	Bonny Gas Transport	Hyundai	Aug-02	Bermuda	S	Moss	4	Nigeria LNG
LNG Taurus	126,300	MOL/LNG Japan	GD Quincy	Aug-79	Marshall Is.	S	Moss	5	Various
LNG Venus	155,000	Osaka/MOL	MHI	Oct-14	Japan	S	Moss	4	Various
LNG Vesta	127,547	Tokyo Gas Consortium	Mitsubishi Nagasaki	Jun-94	Japan	S	Moss	4	Pertamina
LNG Virgo	126,400	MOL/LNG Japan	GD Quincy	Dec-79	Marshall Is.	S	Moss	5	Pertamina
Lobito	160,400	Mitsui/NYK/Teekay	Samsung	Oct-11	Bahamas	DFDE	TZ Mk. III	4	Various
Lusail	138,000	Peninsular LNG	Samsung	May-05	Bahamas	S	TZ Mk. III	4	Qatar
Madrid Spirit	138,000	Teekay LNG Partners	IZAR Puerto Real	Jan-05	Spain	S	GT No 96	4	Engas
Magellan Spirit	165,500	Teekay LNG Partners	Samsung	Sep-08	Denmark	DFDE	TZ Mk. III	4	Various
Malanje	160,400	Mitsui/NYK/Teekay	Samsung	Jul-11	Bahamas	DFDE	TZ Mk. III	4	Various
Maran Gas Achilles	174,000	Maran	Hyundai Samho	Feb-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Agamemnon	174,000	Maran	Hyundai Samho	May-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Alexandria	161,870	Maran	Hyundai Samho	Sep-15	Greece	DFDE	TZ Mk. III	4	Various
Maran Gas Amphipolis	173,400	Maran	Daewoo	Aug-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Apollonia	161,870	Maran	Daewoo	Jan-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Asclepius	145,000	Kristen Navigation	Daewoo	Jul-05	Bermuda	S	GT No 96	4	Qatar
Maran Gas Coronis	145,700	Maran	Daewoo	Sep-07	Greece	S	GT No 96	4	Rasgas II
Maran Gas Delphi	159,800	Maran	Daewoo	Feb-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Efessos	159,800	Maran	Daewoo	Jun-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Hector	174,000	Maran	Hyundai Samho	Nov-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Lindos	159,800	Maran	Daewoo	Jun-15	Greece	DFDE	GT No. 96	4	Various
Maran Gas Mystras	155,900	Maran Gas	Daewoo	May-15	Greece	DFDE	GT No 96	4	various
Maran Gas Pericles	174,000	Maran	Hyundai Samho	June-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Posidonia	161,870	Maran	Daewoo	May-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Roxana	173,400	Maran	Daewoo	Jan-17	Greece	DFDE	GT No 96	4	Various
Maran Gas Sparta	161,870	Maran	Hyundai Samho	April-15	Greece	DFDE	G TZ Mk. III	4	Various
Maran Gas Troy	155,900	Maran Gas	Daewoo	May-15	Greece	DFDE	GT No 96	4	various
Maran Gas Ulysses	174,000	Maran	Hyundai Samho	Jan-17	Greece	DFDE	GT No 96	4	Various
Maria Energy	174,000	Tsakos	Hyundai	Mar-15	Marshall Is.	TFDE	GTT Mk II	4	Various
Marib Spirit	165,000	Teekay LNG	Samsung	May-08	Marshall Is.	DFDE	TZ Mk. III	4	Various
Matthew	126,540	Suez LNG Shiping	Newport News	Jun-79	Bahamas	S	TZ Mk. I	6	Atlantic LNG
Mekaines	266,000	Naklilat	Samsung	Mar-09	Liberia	DRL	GT No 96	4	Qatar-Atlantic Basin
Meridian Spirit	165,500	Teekay LNG	Samsung	Jan-10	Denmark	DFDE	TZ Mk. III	4	Various
Mesaimeer	210,100	Naklilat	Hyundai	Mar-09	Liberia	DRL	GT No 96	4	Qatar-Atlantic Basin
Methane Alison Victoria	145,000	GasLog	Samsung	Aug-07	Bermuda	S	TZ III	4	Eq.Guinea LNG
Methane Becki Anne	170,000	GasLog	Samsung	Sep-10	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Heather Sally	145,000	GasLog	Samsung	Jul-07	Bermuda	S	Tz Mk. III	4	Eq.Guinea LNG
Methane Jane Elizabeth	145,000	GasLog	Samsung	Jun-06	Bermuda	TFDE	TZ Mk. III	4	Engas
Methane Julia Louise	170,000	GasLog	Samsung	Dec-09	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Kari Elin	138,200	Shell	Samsung	Jun-04	Bermuda	S	TZ Mk. III	4	Various
Methane Lake Charles	145,000	Shell	Samsung	Feb-07	Bermuda	S	TZ Mk. III	4	Marathon Oil
Methane Lydon Volney	145,000	Shell	Samsung	Aug-06	Bermuda	S	TZ Mk. III	4	Engas
Methane Mickie Harper	170,000	Shell-GasLog	Samsung	Nov-10	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Nile Eagle	145,000	Shell-GasLog	Samsung	Dec-07	Bermuda	S	TZ Mk. III	4	Engas
Methane Patricia Camila	170,000	Shell-GasLog	Samsung	Oct-10	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Princess	138,159	Golar LNG	Daewoo	2003	UK	S	GT No 96	4	Spot BG
Methane Rita Andre	145,000	GasLog	Samsung	Mar-06	Bermuda	S	TZ Mk. III	4	Engas
Methane Shirley Elizabeth	145,000	GasLog	Samsung	Apr-07	Bermuda	S	TZ Mk. III	4	Marathon Oil
Methane Sprit	165,000	Teekay LNG	Samsung	Mar-08	Singapore	DFDE	TZ Mk. III	4	Various
Milaha Qatar	145,000	Milaha	Samsung	Apr-06	Denmark	S	TZ Mk. III	4	Qatar
Milaha Ras Laffan	138,270	Milaha	Samsung	Mar-04	Denmark	S	TZ Mk. III	4	RasGas II
Min Lu	147,000	China Ships	Hudong	Aug-09	China	S	GT No 96	4	Various
Min Rong	147,000	China LNG Ships	Hudong	Feb-09	Hong Kong	S	GT No 96	4	Australia-China
Mourad Didouche	126,130	SNTM-Hyproc	Atlantique	Jul-80	Algeria	S	GT No 85	5	Sonatrach
Mozah	266,000	QGTC	Samsung	Aug-08	Qatar	DRL	TZ Mk III	5	Qatargas II
Mraweh	137,000	National Gas Shipping	Kvaerner-Masa	Jun-96	Liberia	S	Moss	4	ADGAS
Mubaraz	137,000	National Gas Shipping	Kvaerner-Masa	Jan-96	Liberia	S	Moss	4	Various
Muraq	210,100	J5-K Line	Daewoo	May-08	Marshall Is.	DRL	GT No 96	4	Qatar-Atl'c Basin
Murwab	210,100	J5 Consortium	Daewoo	May-08	Marshall Is.	DRL	GT No. 96	4	Qatargas
Muscat LNG	149,170	Oman Gas/MOL	Kawasaki Sakaide	Mar-04	Japan	S	Moss	4	Oman Gas
Neo Energy	149,700	Tsakos	Hyundai	Feb-07	Liberia	S	GTT Mk II	4	Various
Nizwah LNG	145,000	Oryx LNG Carriers	Kawasaki Sakaide	Dec-05	Japan	S	Moss	4	Oman Gas
Northwest Sanderling	127,525	Australia LNG	Mitsubishi Nagasaki	Jun-89	Australia	S	Moss	4	NWS
Northwest Sandpiper	127,500	Australia LNG	Mitsui Chiba	Feb-93	Australia	S	Moss	4	NWS
Northwest Seaeagle	127,450	Australia LNG	Mitsubishi Nagasaki	Nov-92	Bermuda	S	Moss	4	NWS
Northwest Shearwater	127,500	Australia LNG	Kawasaki Sakaide	Sep-91	Bermuda	S	Moss	4	NWS
Northwest Snipe	127,747	Australia LNG	Mitsui Chiba	Sep-90	Australia	S	Moss	4	NWS
Northwest Stormpetrel	127,600	Australia LNG	Mitsubishi Nagasaki	Dec-94	Australia	S	Moss	4	NWS
Northwest Swallow	127,708	J3 Consortium	Mitsui Chiba	Nov-89	Japan	S	Moss	4	NWS
Northwest Swan	138,000	Australia LNG	Daewoo	Mar-04	Australia	S	GT NO 96	4	NWS
Northwest Swift	127,590	J3 Consortium	Mitsubishi Nagasaki	Sep-89	Japan	S	Moss	4	NWS
Oak Spirit	173,400	Teekay	Daewoo	Jan-16	Bahamas	MEGI-DF	NO. 96 GW	4	Cheniere
Ob River	150,000	Lance Shipping	Hyundai	Oct-07	Marshall Is.	S	TZ Mk. III	4	Various
Onaiza	210,100	Nakilat	Daewoo	Apr-09	Liberia	DRL	GT NO 96	4	Qatar-Atlantic Basin
Pacific Arcadia	147,200	NYK Line	MHI	Oct-14	Bahamas	S	KM	4	Various
Pacific Enlighten	145,000	LNG MT	Mitsubishi	Mar-09	Japan	S	Moss	4	Various
Pacific Eurus	137,000	LNG Marine Transport	Mitsubishi Nagasaki	Mar-06	Bahamas	S	Moss	4	Darwin
Pacific Mimosa	155,300	NYK Line	MHI	Nov-17	Bahamas	S	Moss	4	Australia-Japan
Pacific Notus	137,006	Pacific LNG Shipping	Mitsubishi Nagasaki	Sep-03	Bahamas	S	Moss	5	Darwin
Palu LNG	160,106	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GT No 96	4	Various
Pan Asia	174,000	Teekay	Hudong-Zhonghua	July-17	Bahamas	TFDE	NO. 96 GW	4	Cheniere
Papua	171,800	MOL-China	Hudong	Jan-15	Hong Kong	DFDE	SSD	4	PNG LNG
Polar Eagle	89,880	Polar LNG	IHI Chita	Jun-93	Liberia	S	IHI SPB	4	ConocoPhillips/Marathon
Prachi	173,000	NYK-SCI	Hyundai	Nov-16	Singapore	TFDE	GT No 96	4	Petronet

Provalys	153,500	Gaz de France	Chantiers	Nov-06	France	DFDE	CS1	4	ELNG
Puteri Delima	130,400	MISC	Atlantique	Jan-95	Malaysia	S	GT NO 96	4	Petronas
Puteri Delima Satu	137,100	MISC	Mitsui Chiba	Apr-02	Malaysia	S	GT NO 96	4	Petronas
Puteri Firuz	130,400	MISC	Atlantique	May-97	Malaysia	S	GT NO 96	4	Petronas
Puteri Firuz Satu	137,100	MISC	Mitsubishi Nagasaki	Sep-04	Malaysia	S	GT NO 96	4	Petronas
Puteri Intan	130,400	MISC	Atlantique	Aug-94	Malaysia	S	GT NO 96	4	Petronas
Puteri Intan Satu	137,100	MISC	Mitsubishi Nagasaki	Dec-01	Malaysia	S	GT NO 96	4	Petronas
Puteri Mutiera Satu	137,100	MISC	Mitsui Chiba	Apr-05	Malaysia	S	GT NO 96	4	Petronas
Puteri Nilam	130,400	MISC	Atlantique	Jun-95	Malaysia	S	GT NO 96	4	Petronas
Puteri Nilam Satu	137,100	MISC	Mitsubishi Nagasaki	Sep-03	Malaysia	S	GT NO 96	4	Petronas
Puteri Zamrud	130,400	MISC	Atlantique	May-96	Malaysia	S	GT NO 96	4	Petronas
Puteri Zamrud Satu	137,100	MISC	Mitsui Chiba	Apr-87	Malaysia	S	GT NO 96	4	Atlantic LNG
Raahi	136,000	Petronet LNG Ltd	Daewoo	Dec-04	Malta	S	GT NO 96	4	Qatargas
Ramdane Abane	126,130	SNTM-Hyproc	Atlantique	Jul-81	Algeria	S	GT NO 85	5	Sonatrach
Rasheeda	266,000	QGTC	Samsung	Jun-10	Liberia	DRL	TZ Mk. III		Various
Ribera del Duero Knutsen	173,400	Knutsen	Daewoo	Nov-10	Nor-NIS	DFDE	GT NO. 96	4	Various
Rioja Knutsen	176,300	Knutsen	Daewoo	Dec-16	Nor-NIS	DFDE	TZ Mk III	4	Various
Salalah LNG	147,000	Oman Gas/MOL	Samsung	Dec-05	Japan	S	TZ Mk. III	4	Oman
SCF Polar	71,500	Sovcomflot	Kockums	Aug-69	Liberia	S	GT NO 82	6	Sonatrach
Seishu Maru	162,000	K Line-Transpacific	Kawasaki Sakaide	Jan-15	Panama	S	Moss	4	Australia-Japan
Seri Alam	138,000	MISC	Samsung	Oct-05	Malaysia	S	TZ Mk. III	4	Yemen LNG
Seri Amanah	145,000	MISC	Samsung	Mar-06	Malaysia	S	TZ Mk. III	4	Yemen LNG
Seri Anggun	145,000	MISC	Samsung	Nov-06	Malaysia	S	TZ Mk. III	4	Yemen LNG
Seri Angkasa	145,000	MISC	Samsung	Feb-07	Malaysia	S	TZ Mk. III	4	Petronas
Seri Ayu	145,000	MISC	Samsung	Oct-07	Malaysia	S	TZ Mk. III	4	Various
Seri Bakti	152,300	MISC	Mitsubishi	Mar-07	Malaysia	S	GT NO 96	4	Petronas
Seri Balhaf	152,000	MISC	Mitsubishi	Sep-08	Malaysia	S	GT NO 96	4	Various
Seri Balquis	152,000	MISC	Mitsubishi	Dec-08	Malaysia	S	GT NO 96	4	Various
Seri Begawan	152,300	MISC	Mitsubishi	Dec-07	Malaysia	S	GT NO 96	4	Various
Seri Bijaksana	152,300	MISC	Mitsubishi	Feb-08	Malaysia	S	GT NO 96	4	Petronas
Seri Camar	150,200	MISC	Hyundai	Feb-18	Malaysia	S	Moss	4	Petronas
Seri Camellia	150,000	MISC	Hyundai	Nov-16	Malaysia	S	Moss	4	Petronas
Seri Cenderawasih	150,000	MISC	Hyundai	Jan-17	Malaysia	S	Moss	4	Petronas
Sestao Knutsen	138,000	Knutsen	IZAR Sestao	Jan-07	Spain	S	GT NO 96	4	Atlantic LNG
Sevilla Knutsen	173,400	Knutsen	Daewoo	Jun-10	N.I.S.	DFDE	GT NO 96	4	Various
Shahamah	135,500	National Gas Shipping	Kawasaki Sakaide	Oct-94	Liberia	S	Moss	5	ADGAS
Shangra	266,000	QGTC	Samsung	Nov-09	Liberia	DRL	TZ Mk. III	5	Qatargas IV
Shen Hai	147,100	China LNG	Hudong Zhonghua	Sep-12	China	AB/CC Steam	GT NO 96	4	Various
Simaisma	147,700	Maran Gas Maritime	Daewoo	Jul-06	Greece	S	GT No 96	4	Qatar
SK Splendor	138,375	SK Shipping	Samsung	Mar-00	Panama	S	TZ Mk. III	4	Oman Gas
SK Stellar	138,375	SK Shipping	Samsung	Dec-00	Panama	S	TZ Mk. III	4	RasGas
SK Summit	138,000	SK Shipping	Daewoo	Aug-99	Panama	S	GT NO 96	4	RasGas
SK Sunrise	138,306	I. S. Carriers	Samsung	Sep-03	Panama	S	TZ Mk. III	4	RasGas
SK Supreme	138,200	SK Shipping	Samsung	Jan-00	Panama	S	TZ Mk. III	4	RasGas
Sohar LNG	137,250	Oman Gas/ MOL	Mitsubishi Nagasaki	Oct-01	Malta	S	Moss	5	Oman Gas
Solaris	155,000	GasLog	Samsung	Jul-14	Bermuda	TFDE	TZ Mk. III	4	Various
Sonangol Benguela	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GT No. 96	4	Angola LNG
Sonangol Etosha	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GT No. 96	4	Angola LNG
Sonangol Sambizanga	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GT No. 96	4	Angola LNG
Southern Cross	172,000	MOL	Hudong	May-15	Hong Kong	DRL	GT NO. 96	4	Various
Soyo	160,400	Mitsui/NYK/Teekay	Samsung	May-11	Bahamas	DFDE	TZ Mk. III	4	Various
Spirit of Hela	177,000	MOL	Hyundai	Oct-09	Panama	DFDE	TZ Mk. III	4	Various
Stena Blue Sky	145,700	Stena	Daewoo	Jan-06	Panama	S	GT No 96	4	Various
Stena Clear Sky	171,800	Stena	Daewoo	Sep-10	Panama	DFDE	GT NO 96	4	Various
Stena Crystal Sky	171,800	Stena	Daewoo	Jul-10	Panama	DFDE	GT NO 96	4	Various
STX Kolt	145,700	STX Panocean	Korea Hanjin	Nov-08	Panama	DFDE	TZ Mk. III	4	Various
Suez Point Fortin	154,200	Trinity LNG	Koyo Japan	Nov-09	Panama	S	TZ Mk. III	4	Yemen LNG
Taitar No. 1	145,000	NYK Line	Mitsubishi	Oct-09	Liberia	S	Moss	4	Various
Taitar No. 3	145,000	NYK Line	Mitsubishi	Jan-10	Liberia	S	Moss	4	Various
Taitar No. 4	145,000	NYK	Mitsubishi	Jan-10	Liberia	S	Moss	4	Various
Tangguh Batur	145,700	Sovcomflot/NYK	Daewoo	Dec-08	Cyprus	S	GT NO 96		Tangguh
Tangguh Foja	155,000	K Line	Samsung	Jul-08	Panama	DFDE	TZ Mk. III	4	Tangguh LNG
Tangguh Hiri	155,000	Teekay LNG	Hyundai	Nov-08	IOM	DFDE	TZ Mk. III	4	Tangguh
Tangguh Jaya	145,700	K Line	Samsung	Nov-08	Panama	DFDE	TZ Mk. III	4	Tangguh
Tangguh Palung	155,000	K Line	Samsung	Mar-09	Panama	DFDE	TZ Mk. III	4	Tangguh
Tangguh Sago	155,000	Teekay LNG	Hyundai	Mar-09	IOM	DFDE	TZ Mk. III	4	Tangguh LNG
Tangguh Towuti	145,700	Sovcomflot/NYK	Daewoo	Oct-08	Cyprus	S	GT NO 96	4	Tangguh
Tembek	216,200	OSG/Nakilat	Samsung	Sep-07	Marshall Is.	DRL	TZ Mk. III	4	Qatargas II
Tenaga Satu	130,000	MISC	Dunkerque	Sep-82	Malaysia	S	GT NO 88	5	Petronas
Torben Spirit	173,000	Teekay	Daewoo	Feb-17	Bahama	MEGI-DF	No 96 GW	4	Various
Trinity Arrow	154,900	K Line	Imabari Shipbuilding	Mar-08	Panama	S	TZ Mk. III	4	Various
Umm Al Amad	210,100	J5	Daewoo	Aug-08	Marshall Is.	DRL	GT NO 96	4	Ras Gas III
Umm Al Ashtan	137,000	National Gas Shipping	Kvaerner- Masa	May-97	Liberia	S	Moss	4	ADGAS
Umm Bab	145,000	Kristen Navigation	Daewoo	Nov-05	Bermuda	S	GT NO 96	4	Qatargas
Umm Slaal	266,000	QGTC	Samsung	Nov-08	Qatar	DRL	TZ Mk. III	5	Qatargas
Valencia Knutsen	173,400	Knutsen	Daewoo	Sep-10	Nor-NIS	DFDE	GT NO. 96	4	Various
Velikiy Novgorod	170,200	SovComFlot	STX	Feb-14	Liberia	DFDE	GT No. 96	4	Various
Wakaba Maru	125,000	J3 Consortium	Mitsui Chiba	Apr-85	Japan	S	Moss	5	Pertamina
WilEnergy	125,500	Awilco LNG	Mitsubishi	Oct-83	NIS	S	Moss	5	Various
WilForce	156,000	Teekay LNG	Daewoo	Aug-13	NIS	DFDE	GT NO 96	4	Various
WilGas	125,500	Awilco LNG	Mitsubishi	Jul-84	NIS	S	Moss	5	Various
WilPower	125,500	Awilco LNG	Mitsubishi	Jul-84	NIS	S	Moss	5	Various
Woodside Cheney	174,000	Maran	Hyundai Samho	March-16	Greece	DFDE	GT No 96	4	Various
Woodside Donaldson	165,500	Teekay LNG	Samsung	Dec-09	Singapore	DFDE	TZ Mk. III	4	Various
Woodside Goode	159,800	Maran	Daewoo	Jul-14	Greece	DFDE	GT No. 96	4	Various
Woodside Reeswithers	173,400	Maran	Daewoo	Nov-16	Greece	DFDE	GT No 96	4	Various
Woodside Rogers	155,900	Maran Gas	DSME	Jul-13	Greece	DFDE	GT NO 96	4	Various
Yari LNG	159,983	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GT No 96	4	Various
Yenisei River	155,000	Dynagas	Hyundai	Jul-13	Marshall Is.	DFDE	TZ Mk. III	4	Various
YK Sovereign	127,125	SK Shipping	Hyundai	Dec-94	Panama	S	Moss	4	Pertamina
Zarga	266,000	QGTC	Samsung	Dec-09	Liberia	DRL	TZ Mk. III	5	Qatar-Atlantic
Zekreet	135,420	J4 Consortium	Mitsui Chiba	Dec-98	Japan	S	Moss	5	Qatargas

Any observations, additions or suggested revisions to the LNG journal World LNG Carrier Fleet list should be sent to editor@lngjournal.com

LNG Import Terminals

Explanatory Notes

- The tables do not include the following types of LNG facilities :
  - Small marine satellite terminals receiving LNG from liquefaction plants in their own country (such as exist in Norway) or which receive LNG transhipped from nearby reception terminals in their own country (such as in Japan)
  - Satellite LNG storage facilities that receive LNG transported only by road or rail
- Expansions of LNG reception terminals are only shown if they involve new storage tanks
- Where there is a blank in the table the information is uncertain or unknown.

Any comments on the tables, and corrections / additional information from terminal shareholders and project developers would be most welcome, and should be sent to John McKay e-mail editor@lngjournal.com

Country	Location (Project)	Owners	Start up	Storage Tanks	Storage Capacity
Belgium	Zeebrugge	Fluxys	1987	4	380,000
Canada	Canaport Saint John	Irving Oil, Repsol	2009	3	480,000
Chile	Quintero	ENAP, Metrogas, Enagas	2009	3	334,000
	Mejillones	Engie, Codelco	2010	1	175,000
China	Beihai LNG, Guangxi	Sinopec	2015	4	640,000
	Dalian	PetroChina	2011	3	480,000
	Dongguan, Guangdong	Jovo Group	2013	2	160 000
	Fujian LNG (Xiuyu)	CNOOC, Fujian I&D Corp.	2008	2	640,000
	Guangdong	CNOOC,BP	2006	3	480,000
	Haikou, Hainan LNG	CNOOC	2014	3	480,000
	Ningbo, Zheijang	CNOOC, Zhejiang Energy	2012	3	480,000
	Qingdao, Shandong	Sinopec	2014	3	480,000
	Rudong	PetroChina	2011	3	530,000
	Shanghai	CNOOC, Shenergy Group	2009	3	495,000
	Shanghai, Mengtougou	Shanghai Gas	2008	3	120 000
	Shenzen, Diefu	CNOOC	2016	2	320,000
	Tangshan, Hebei	PetroChina	2013	3	480,000
	Tianjin North	Sinopec	2017	2	320,000
	Yuedong, Guangdong	CNOOC	2016	2	320,000
	Zhuhai, Gaolan	CNOOC	2013	3	480,000
Dominican Republic	Punta Caucedo	AES Andres	2003	1	160 000
Finland	Pori	Gasum Skangas	2016	1	30,000
France	Fos Tonkin	Elengy	1972	3	150,000
	Montoir-de-Bretagne	Elengy	1980	3	360,000
	Fos Cavaou	Engie, Total	2010	3	330,000
	Dunkirk LNG	EDF, Fluxys, Total	2016	3	570,000
Greece	Revithoussa	DEPA	2000	3	225,000
India	Dabhol	GAIL, NTPC (Ratnagiri Gas & Power)	2009	3	480,000
	Dahej	Petronet LNG	2004	4	592,000
	Hazira	Shell India, Total	2005	2	320,000
	Kochi, Kerala	Petronet LNG	2013	2	320,000
Indonesia	Arun	Pertamina	2015	5	507,000
Italy	Panigaglia	Snam	1969	2	100,000
	Porto Levante (offshore GBS)	ExxonMobil, Qatar Petroleum, Edison Gas	2009	2	250,000
Japan	Negishi	Tokyo Gas	1969	14	1,180,000
	Sodegaura	Tokyo Gas	1973	35	2,660,000
	Ohgishima	Tokyo Gas	1998	4	850,000
	Higashi-Ohgishima	Tokyo Electric	1984	9	540,000
	Futtsu	Tokyo Electric	1985	10	1,110,000
	Yokkaichi LNG	Chubu Electric	1988	4	320,000
	Kawagoe	Chubu Electric	1997	6	840,000
	Yokkaichi Works	Toho Gas	1991	2	160,000
	Chita LNG Joint	Toho Gas, Chubu Electric	1978	4	300,000
	Chita LNG	Toho Gas, Chubu Electric	1983	7	640,000
	Chita - Midorihama	Toho Gas	2001	3	600,000
	Senboku I	Osaka Gas	1972	4	180,000
	Senboku II	Osaka Gas	1977	18	1,585,000
	Himeji	Osaka Gas	1984	8	740,000
	Himeji LNG	Kansai Electric	1979	7	520,000
	Yanai	Chugoku Electric	1990	6	480,000
	Niigata	Nihonkai LNG, Tohoku Electric	1984	8	720,000
	Oita	Oita Gas, Kyushu Electric	1990	5	460,000
	Tobata	Kitakyushu LNG	1977	8	480,000
	Fukuoka	Saibu Gas	1993	2	70,000
	Sodeshi	Shizuoka Gas	1996	3	337,200
	Hatsukaichi	Hiroshima Gas	1996	2	170,000
	Kagoshima	Nippon Gas	1996	2	136,000
	Shin-Minato	Sendai City Gas	1997	1	80,000
	Nagasaki	Saibu Gas	2003	1	36,000
	Sakai	Kansai Electric, Cosmo OIl	2006	3	420,000
	Mizushima	Nippon Oil, Chugoku Electric	2006	2	320,000
	Sakaide	Shikoku Electric, Cosmo Oil	2011	1	180,000
	Ishikari LNG	Hokkaido Gas, Hokkaido Electric	2012	2	380,000
	Okinawa	Okinawa Electric Power	2012	2	280,000
	Naoetsu	Inpex	2013	2	360,000
	Joetsu	Chubu	2011	3	540,000
	Hachinohe LNG	Nippon Oil	2015	2	280,000
	Hitachi LNG	Tokyo Gas	2015	1	230,000
	Soma Fukushima	Japan Petroleum Exploration	2017	1	225,000
Korea	Boryyeong	GS Energy, SK E&S	2017	3	200,000
	Incheon	Kogas	1996	20	2,880,000
	Kwangyang	POSCO	2005	4	530,000
	Pyeong-Taek	Kogas	1986	23	3,360,000
	Samcheok	Kogas	2014	3	600,000
	Tong-Yeong	Kogas	2002	17	2,620,000
Malaysia	Pengerang Johor	Petronas Gas	2017	2	400,000
Mexico	Altamira	Vopak, Enagas	2006	2	300,000
	Energia Costa Azul	Sempra LNG	2008	2	320,000
	Manzanillo	Samsung, Kogas, Mitsui	2012	2	300,000

LNG Import Terminals (continued)

Country	Location (Project)	Owners	Start up	Storage Tanks	Storage Capacity
Netherlands	Gate LNG	Gasunie, Royal Vopak	2011	3	540,000
Phillipines	Pagbilao LNG	Energy World Corp.	2017	1	130,000
Poland	Swinoujscie	Baltic Gaz System	2015	2	320,000
Portugal	Sines	REN Atlantico	2004	3	390,000
Puerto Rico	Penuelas	EcoElectrica	2000	1	160,000
Singapore	Singapore	Singapore Energy Authority	2013	3	540,000
Spain	Barcelona	Enagas	1969	8	840,000
	Huelva	Enagas	1988	5	610,000
	Cartagena	Enagas	1989	5	587,000
	Bilbao	Enagas, EVE	2003	3	450,000
	Sagunto	GNF, Osaka Gas, Oman Oil	2006	4	600,000
	Reganosa, Ferrol	Galicia, Sonatrach, Tojeiro	2006	2	300,000
	El Musel, Gijón,	Enagas	2013	2	300,000
Taiwan	Yung-An	CPC	1990	6	690,000
	Tai-Chung	CPC	2009	3	480,000
Thailand	Map Ta Phut	PTT LNG	2011	2	320,000
Turkey	Marmara Ereglisi	Botas	1994	3	255,000
	Izmir	EgeGaz	2006	2	280,000
USA	Everett	Suez LNG NA	1971	2	155,000
	Lake Charles	Shell, ETE	1982	4	425,000
	Elba Island	Kinder	2001	5	535,000
	Cove Point	Dominion	2003	5	530,000
	Freeport	Freeport LNG Development	2008	2	320,000
	Cameron	Sempra LNG	2009	3	480,000
	Golden Pass, TX	Qatar Petroleum, ExxonMobil	2010	5	775,000
	Pascagoula, MS	Gulf LNG, Kinder	2012	2	320,000
UK	Isle of Grain	National Grid	2005	8	1,000,000
	South Hook	ExxonMobil, Qatar Petroleum,Total	2009	5	775,000
	Dragon LNG, Milford Haven	Shell, Petronas	2009	2	310,000

LNG Import Terminal Projects

Country	Location/Project	Owners/Project Developers	Start up	Storage Tanks	Storage Capacity
China	Zhoushan Zhejiang	Enn Group	2018	2	320,000
Finland	Tornio	Gasum Skangas	2018	1	30,000
Gibraltar	Gasnor	Shell	2018	1	5,000
India	Ennore	Indian Oil Corp	2018	2	320,000
	Mundra	Gujarat State Petroleum, Adani Group	2018	2	320,000
	FSRU Andhra Pradesh	Engie, Andhra Pradesh Gas	2018	1	135,000
	Pipovav LNG (FSRU), Gujarat	Swan Energy	2018	2	320,000
	Andhra Pradesh	Hindustan LNG, Andhra Pradesh	studies	1	135,000
Indonesia	Labuhan Maringgai	Perusahaan Gas Negara	2018	1	135,000
Malaysia	Lahad Datu LNG, Sabah	Petronas	2018	studies	
Panama	Costa Norte	AES	2018	1	130,000
UK	Port Meridian, Barrow-in-Furness	Port Meridian Energy Ltd.	2020	1	150,000
Uruguay FSRU	Montevideo	Gas Sayago, Mitsui Osk Lines	2019	1	230,000

LNG FSRU Import Facilities

Country	Location (Project)	Owners	Start up
Argentina	Bahia Blanca GasPort	Excelerate/YPF Repsol	2008
	Escobar GasPort	Excelerate/Enarsa	2011
Brazil	Pecem, FSRU	Petrobras	2009
	Guanabara Bay FSRU	Petrobras	2009
	Salvador, Bahia FSRU	Petrobras	2013
Colombia	Cartagena FSRU	Promigas, Sociedad Portuaria El Cayao	2016
Egypt	Ain Sokhna, Suez	EGAS, Hoegh	2015
	Ain Sokhna, Suez	EGAS, BW Gas	2015
Indonesia	Lampung	Hoegh LNG, PGN LNG	2014
	Nusantara (Jakarta Bay)	Golar LNG, Pertimana	2012
Italy	Livorno	OLT Offshore LNG Toscana	2013
Jordan	Aqaba, Jordan	Golar LNG	2015
Kuwait	Mina Al-Ahmadi	KPC	2009
Lithuania	Klaipeda	Klaipedos Nafta Hoegh LNG	2014
Malaysia	Malacca FSRU	Petronas	2012
Malta	FSU Armada Mediterrana	ElectroGas	2016
Pakistan	Port Qasim	Excelerate, Engro Corp	2015
	Port Qasim	BW-Mitsui, PGP Consortium	2017
Turkey	Aliaga FSRU, Neptune	Etki LNG	2016
	Dortyol FSRU Challenger	Botas	2018
UAE	Ruwais, Abu Dhabi	Gasco (UAE)	2016
	Jebel Ali Port, Dubai	DSA (UAE)	2010
UK	Teesside GasPort	Excelerate	2007

LNG Export Projects

Country	Location/Project	Project Developers	Planned Start Up	Number of Trains	Capacity In MTPA
AUSTRALIA	Browse LNG	Woodside, BHP, BP Chevron, Shell, Mitsubishi, Mitsui	2021+	2	10.0
	Ichthys LNG	INPEX, Total	2018	2	8.4
	Prelude FLNG	Shell, Inpex, Kogas CPC	2018	1	3.5
CANADA	Bear Head LNG, Nova Scotia	LNG Ltd.	2024	4	8.0
	GNL Quebec, Saquenay	Freestone Capital and Breyer Capital	2024	4	10.0
	Goldboro LNG, Nova Scotia	Pieridae Energy	2024	2	10.0
	Kitimat LNG, BC	Woodside, Chevron	2024	2	10.0
	LNG Canada, BC	Shell, Mitsubishi, Kogas, PetroChina	2024	2	12.0
	Melford LNG project, Nova Scotia	H-Energy Hiranandani Group	Studies		
	Kwispaa FLNG, Vancouver	Steelhead LNG	2024	4	12.0
	Vancouver Tilbury	WesPac Midstream	2021	1	3.25
	Woodfibre LNG, Squamish	Pacific Oil & Gas Co	2020	2	2.1
EQ.GUINEA	Equatorial Guinea Fortuna FLNG	Ophir, Golar LNG, Schlumberger, GEPetrol	2019	1	2.0
INDONESIA	Sengkang LNG	Energy World Corp.	2018	4	2.0
MALAYSIA	Rotan FLNG (Sabah)	Petronas, Murphy Oil	2019	1	1.5
MOZAMBIQUE	Area 1 Onshore	Anadarko Petroleum and partners	2021	2	10
	Area 4 Onshore	Eni and partners	2021	2	10
	Area 4 FLNG	Eni and partners	2019	1	2.5
NIGERIA	NLNG Train 7	NNPC, Shell, BP, Total	2020+	1	8.4
PAPUA NEW GUINEA	Elk-Antelope LNG	Total, ExxonMobil Oil Search, Petromin	Studies		
RUSSIA	Sakhalin II expansion	Gazprom, Shell, Mitsui, Mitsubishi	2021	studies	
	Vladisvostok LNG	Gazprom, Itochu, various	2021	2	10.0
USA	Alaska LNG Nikiski	Alaska Gasline Development Corp.	2022	3	20.0
	Annova LNG, Brownsville	Exelon Corp.	2021	6	6.0
	Cameron LNG, Louisiana	Sempra	2018	5	24.92
	Commonwealth LNG, Louisiana	Commonwealth LNG LLP	2022	8	9.0
	Corpus Christi Liquefaction, Texas	Cheniere	2019	5	22.5
	Delfin LNG, Louisiana	Delfin, Hoegh	2021	3	9.0
	Driftwood LNG, Louisiana	Tellurian Investments	2022	6	26.0
	Elba Island, Georgia	Kinder Morgan, EIG Energy	2018	10	2.5
	Freeport LNG, Texas	Freeport LNG	2018	4	20.4
	Golden Pass, Texas	Qatar Petroleum, ExxonMobil	2021	3	15.6
	Jordan Cove, Coos Bay	Pembina Corp.	2024	2	7.8
	Lake Charles, Louisiana	Shell, ETE	2024	3	15.0
	Magnolia LNG	Louisiana LNG Ltd.	2021	4	8.0
	Port Arthur LNG	Sempra	2021	2	10.0
	Rio Grande LNG	NextDecade	2021	6	27.0
	Sabine Pass LNG, Louisiana	Cheniere	2018-19	2	9.0
	Texas LNG Brownsville	Chandra, Meyer, Samsung, others	2021	2	4.0
	VG LNG (Cameron Parish)	Venture Global	2021	5	10.0
	VG LNG (Plaquemines)	Venture Global	2021	10	20.0

LNG Exporters

Country	Location/Project	Shareholders	Start up	Liquefaction		Storage	
				Trains	capacity (nominal) mtpa	No. of tanks	Total capacity m^3
ABU DHABI (UAE)	Das Island (Adgas)	ADNOC, Mitsui, BP, Total	1977	2	3.2	3	240,000
			1994	1	2.5		
ALGERIA	Arzew	Sonatrach GL4Z	1964	3	1.1	3	35,000
	Arzew	Sonatrach GL1Z	1978	6	7.8	3	300,000
	Arzew	Sonatrach GL2Z	1980	6	8.0	3	300,000
	Arzew	Sonatrach	2014	1	4.7		
	Skikda	Sonatrach GL1K II	1980	3	3.0	5	308,000
	Skikda	Sonatrach (rebuild)	2013	1	4.5		
ANGOLA	Soyo	Sonangol, Chevron, BP, ENI, Total	2012	1	5.2	2	370,000
AUSTRALIA	Karratha	NWS Woodside, Shell, BHP	1989	2	5.0	4	260,000
		(BP, Chevron	1992	1	2.5	1	130,000
		(Mistubishi/Mitsui)	2004	1	4.4	1	130,000
		NWS partners	2008	1	4.4	1	130,000
	Darwin	Darwin (Bayu Undan) ConocoPhillips, Santos, Eni, Inpex, TEPCO, Tokyo Gas	2006	1	3.5	1	188,000
	Australia Pacific LNG	ConocoPhillips, Origin Energy, Sinopec	2016	2	7.5	2	320,000
	Gladstone LNG	Santos, Petronas, Total, Kogas	2015	2	7.8	2	280,000
	Gorgon LNG	Chevron, Shell, ExxonMobil	2016	3	15.6	2	360,000
	Pluto LNG	Woodside, Tokyo Gas, Kansei	2012	1	4.8	2	240,000
	QCLNG	Shell, CNOOC	2014	2	8.0	2	280,000
	Wheatstone LNG	Chevron, Woodside, Kuwait (KUFPEC), Jera, Kyushu	2017	2	8.9	2	300,000
BRUNEI	Lumut	Brunei/Shell/Mitsubishi/Total	1972-74	5	7.2	3	176,000
EGYPT	Damietta	Union Fenosa, EGPC, EGAS	2004	1	5.0	2	300,000
	Idku	EGPC, EGAS, Shell, Total, Petronas	2005	2	7.2	2	280,000
EQ.GUINEA	Bioko Island	Marathon, Sonagas, Mitsui, Marubeni	2007	1	3.4	2	272,000
INDONESIA	Bontang I	Pertamina, VICO, JILCO, Total	1977	2	5.2	5	635,000
	Bontang II		1983	2	5.2		
	Bontang III		1989	1	2.8		
	Bontang IV		1993	1	2.8		
	Bontang V		1997	1	2.8		
	Bontang VI		1999	1	3.0		
	Sulawesi LNG	Medco Energi, Pertamina, Mitsubishi	2015	1	2.0	1	170,000
	Tangguh	BP, MI Berau, CNOOC, Nippon, LNG Japan	2008	2	7.6	2	340,000
MALAYSIA	Bintulu (MLNG Satu)	Petronas, Sarawak, Mitsubishi	1983	3	8.1	4	260,000
	Bintulu (MLNG Dua)	Petronas, Shell, Sarawak, Mitsubishi	1995	3	7.8	1	65,000
	Bintulu (MLNG Tiga)	Petronas, Shell, Sarawak, Mitsubishi, Nippon Oil	2003	2	6.8	1	120,000
	Bintulu Train 9	Petronas	2016	1	3.6		
	Kanowit FLNG	Petronas	2016	1	1.2		
NIGERIA	Bonny Island	NNPC, Shell, Total, Eni	1999	2	6.4	2	168,400
		Nigeria LNG (formed by above)	2002	1	3.2	1	84,200
		Nigeria LNG	2006	2	8.2		
		Nigeria LNG	2008	1	4.1	1	84,200
NORWAY	Snøhvit/Melkoya Island	Statoil, Total, GDF-Suez, Petoro	2007	1	4.2	2	280,000
OMAN	Oman LNG	Oman Govt., Shell, Total, Korea LNG Mitsubishi, Mitsui, Partex and Itochu	2000	2	7.1	2	240,000
		Oman Govt.,Oman LNG Union Fenosa, Osaka Gas, & Itochu	2006	1	3.7	2	240,000
PAPUA NEW GUINEA	PNG LNG	ExxonMobil, Oil Search, Santos, JX Nippon Oil	2014	2	6.9	2	320,000
PERU	Peru LNG	Hunt Oil, Shell, Marubeni, SK Group	2010	1	4.4	2	260,000
QATAR	Qatargas 1-T1&2	QP, ExxonMobil, Total, Marubeni, Mitsui	1997	2	6.4	4	340,000
	Qatargas 1-T3	QP, ExxonMobil, Total, Marubeni, Mitsui	1999	1	3.1		
	Qatargas II-T1	QP, ExxonMobil	2009	1	7.8		
	Qatargas II-T2	QP, ExxonMobil, Total	2009	1	7.8	8	1,160,000
	Qatargas III-T1	QP, ConocoPhillips, Mitsui	2010	1	7.8		
	Qatargas IV-TI	QP, Shell	2010	1	7.8		
	RasGas I- T1&2	QP, ExxonMobil, Kogas, Itochu, LNG Japan	1999	2	6.6		
	RasGas II- T3	QP, ExxonMobil	2004	1	4.7		
	RasGas II- T4	QP, ExxonMobil	2005	1	4.7	6	840,000
	RasGas II- T5	QP, ExxonMobil	2007	1	4.7		
	Rasgas III – T6	QP, ExxonMobil	2009	1	7.8		
	Rasgas III – T7	QP, ExxonMobil	2010	1	7.8		
RUSSIA	Sakhalin Island	(Sakhalin Energy) Gazprom, Shell, Mitsui, Mitsubishi	2009	2	9.6	2	200,000
	Yamal LNG Siberia	Novatek, Total, CNPC, Silk Fund	2017	3	16.5		
TRINIDAD & TOBAGO	Point Fortin Train 1	BP, Shell, CIC, NGC	1999	1	3.0	2	204,000
	Train 2	BP, Shell	2002	1	3.3	1	160,000
	Train 3	BP, Shell	2003	1	3.3	1	160,000
	Train 4	BP, Shell, NGC	2005	1	5.2	1	160,000
USA	Cheniere Sabine Pass	Cheniere Energy	2016	4	18.0	5	800,000
	Cove Point LNG	Dominion Energy	2017	1	5.3	7	695,000
YEMEN	Bal-Haf	Yemen LNG, Total, Yemen Gas, Hunt Oil, SK Group, Hyundai	2009	2	6.7	2	320,000