LNG journal

The World's Leading LNG publication

40 pages essential LNG news!

May 2020

In this issue:

India has LNG future already mapped out as cargo volumes are set to double

Current Indian LNG terminal and pipeline plans could support 500 cargoes per annum

India began importing liquefied natural gas in 2004 and since then a lack of connectivity for the LNG receiving terminal infrastructure has led to supply limitations.

There are now six LNG receiving terminals in operation in India with five on the West Coast, Dahej, Hazira, Dabhol, Kochi and Mundra and still just one on the East Coast.

That's at Kamarajar Port in Tamil Nadu, previously called Ennore and located about 25 kilometres north of Chennai.

Regas growth

India's monthly imports are running at volumes of around 2.55 million tonnes (3.45 billion cubic metres) per month.

The total of LNG imports has been rising towards 250 cargoes a year as more infrastructure is constructed, including pipelines to reach more industrial and city-gas customers.

Analysts believe that with its LNG terminal and pipeline proposals, India's needs could be for around 500 cargoes a year by 2030.

However, much more urgency is required to push the industry forward for reasons of economic development.

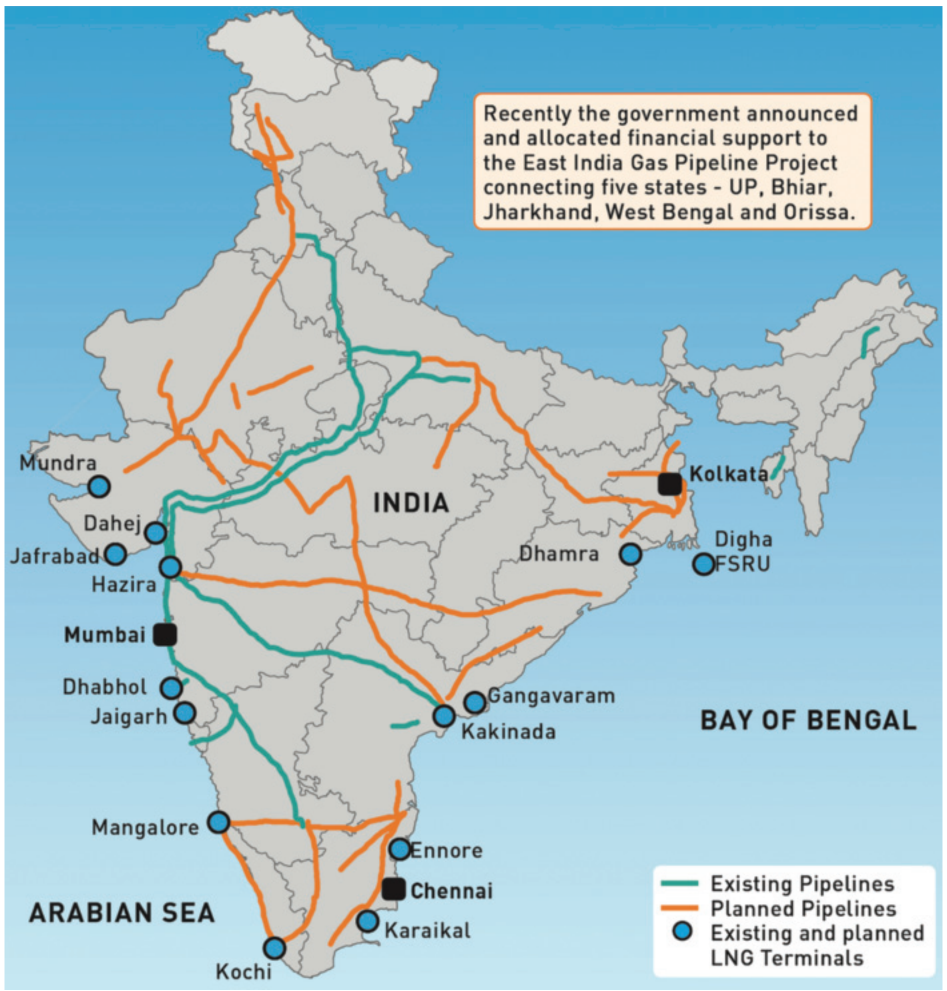
The LNG imports cost India around $900 million per month and come from countries such as Qatar, Australia, the US and the producing nations of West Africa.

Costs rise

The LNG bill for the current fiscal year is expected to be around $9.5 billion.

Monthly shipments of LNG are now higher than the level of domestic natural gas output, which amounts to around 2.60 Bcm per month.

The lack of inland pipeline connectivity to the downstream market especially limits the use of regasification terminals to their full capacity.



Indian pipeline and terminal build-out will gather pace by year-end

As a result, the country's total receiving capacity remains at only 20-30 billion cubic metres per annum despite a nameplate capacity of over 50 Bcm.

The government has long planned to build new terminals, though technical and financial issues have pushed back the development of new regasification terminals since 2013.

At least four more import terminals are planned to start operations in the next few years as well as an array of pipelines and other infrastructure to encourage city-gas use.

Jaigarh project

The Indian Hiranandani Group has a floating storage and regasification import project at Jaigarh port, south of the West Coast city of Mumbai, and this is the next terminal to come on line for commercial operations.

When fully operational, the Jaigarh terminal will supply customers through the pipeline connected to national gas grids at Dabhol.

However, there will still be only one LNG terminal for the whole East Coast of India by the end of 2020 even though about half-a-dozen others are planned.

Dhamra expectations

Indian Prime Minister Narendra Modi inaugurated the Kamarajar LNG terminal on the East Coast as he also pushes for more pipeline construction.

Another East Coast terminal is being advanced.

Gas Authority of India and the and the Adani Group, along with Indian Oil, are

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developing the Dhamra LNG terminal in the East Coast state of Odisha.

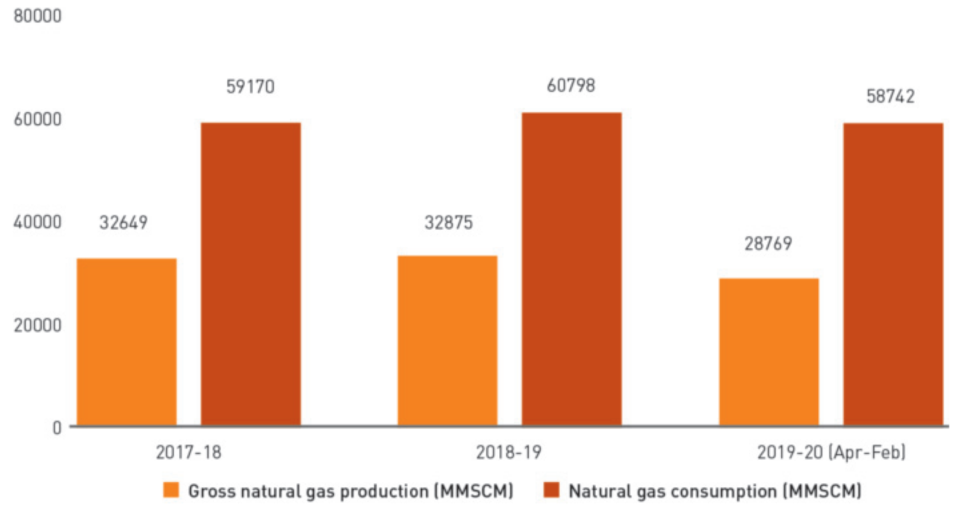
The Dhamra terminal when completed would serve city-gas and power projects as well as industrial customers.

Before it became on LNG nation, India had relied on its domestic production of associated gas from oilfields to meet the country's requirement for both power generation and industrial uses.

However, the country's strong economic and population growth led to further acceleration in natural gas demand, led by industrial uses.

The government's strategy of expanding the role of natural gas in India, together with the development of the domestic pipeline network and the market and pricing, are expected to enable further growth in natural gas consumption.

One of the main users of natural gas is the crucial Indian fertilisers industry that supports domestic agriculture's needs and food production.



Domestic natural gas output and the nation's gas consumption figures

Network

The first phase of the 2,655 kilometres-long Jagdishpur–Haldia and Bokaro–Dhamra gas pipeline project have been completed.

A 585 km-long section connecting to the eastern Indian states will also be further extended by 729 km in the next phase.

H-Energy's new terminal at Jaigarh port is India's first to use a floating storage and regasification unit and will serve the Ratnagiri district of the state of Maharashtra.

The pipeline connection has especially been a crucial step in reviving the fertiliser industry in the eastern region of India, where most of the natural gas-fired power and fertiliser plants have been mothballed since 2013 with the decline of domestic production, namely from the KG D6 offshore basin.

The pipeline is also expected to supply natural gas to refineries, steel plants and other industries in the region.

Maharashtra needs

GAIL, the country's main natural gas infrastructure operator, is currently developing several pipeline expansion projects, which total over 4,200km.

H-Energy's new terminal at Jaigarh port is India's first to use a floating storage and regasification unit and will serve the Ratnagiri district of the state of Maharashtra.

Phase-I of the project consists of a jetty-based FSRU with 4 MTPA of capacity.

The facility is connected to the market through two major natural gas pipeline networks, namely Dabhol-Bangalore Pipeline (DBPL) and Dahej-Uran-Panvel-Dabhol Pipeline (DUPL-DPPL) at Dabhol.

Adani Ports is constructing its onshore LNG terminal at Dhamra port in Odisha, on India's northeast coast.

The terminal will have an initial regasification capacity of 5 MTPA, expandable to 10 MTPA and two full containment tanks of 180,000 cubic metres capacity each.

Natural gas from the Dhamra facility will be an important supply source to the Urja Ganga Pipelines Project for national infrastructure being pushed forward by Prime Minister Modi to boost East Coast city-gas connections.

Pipelines

The pipeline expansion venture involves laying an additional 2,540 kilometres of pipelines in five eastern states to provide gas for 40 districts and 2,600 towns and villages.

Indian Oil and Gail have booked regasification capacity for 3 MTPA and 1.5 MTPA, respectively. The terminal is expected to be commissioned during the second half of 2021.

Another FSRU project is envisaged by Swan Energy Ltd. It is progressing with its 5 MTPA LNG terminal at Jafrabad port in Gujarat.

The FSRU was ordered from Korea's Hyundai Heavy Industries shipyard in August 2017. A jetty is planned to handle the largest LNG carriers from Qatar.

Swan is aiming to finish its construction activities for the onshore links during 2020.

Another project in the planning stage is from Atlantic Gulf & Pacific (AG&P) and is a small-scale facility with 1 MTPA of capacity and FSRU-based at Karaikal Port in South India.

Start-ups

Commercial operations are expected by the fourth quarter of 2021.

HPCL Shapoorji Energy has awarded an engineering, procurement and construction contract to Toyo Engineering for a new regasification plant at Chhara

in Gujarat State on the West Coast.

> *Adani and Total said they would set up a first Indian venture with the objective of building a retail network of 1,500 service stations over a period of 10 years*

The regasification terminal will have a send-out capacity of 5 MTPA and a storage capacity of 200,000 cubic metres. It is scheduled to be completed at the beginning of 2022.

Expansion projects for existing facilities are also moving ahead. Petronet LNG, owner of the Dahej and Kochi terminals, has completed the expansion of Dahej facility. The nameplate regasification capacity of the terminal is now 17.5 MTPA, after having added two vaporizers.

Fuel market

The company also commissioned India's first LNG fuel station and launched the first commercially approved and registered LNG bus to commute its employees. It has also commissioned its second LNG fuel station at the Kochi terminal.

The Dabhol terminal in Maharashtra is in the process of developing a breakwater to improve safety of access and this should increase capacity to 5 MTPA.

In addition, it is commissioning its third storage tank.

Just over a year ago Shell announced completion of the acquisition of 26 percent equity interest in the Hazira LNG terminal held by French major Total.

However, Total is firmly in the Indian LNG business and has expanded its partnership with the Adani Group to contribute to the development of the Indian natural gas market.

Ambitions

Adani Group Chairman Gautam Adani and Total Chairman and Chief Executive Patrick Pouyanne signed an agreement for a 10-year investment plan in the Indian market

Adani and Total said they would set up a first Indian venture with the objective of building a retail network of 1,500 service stations over a period of 10 years

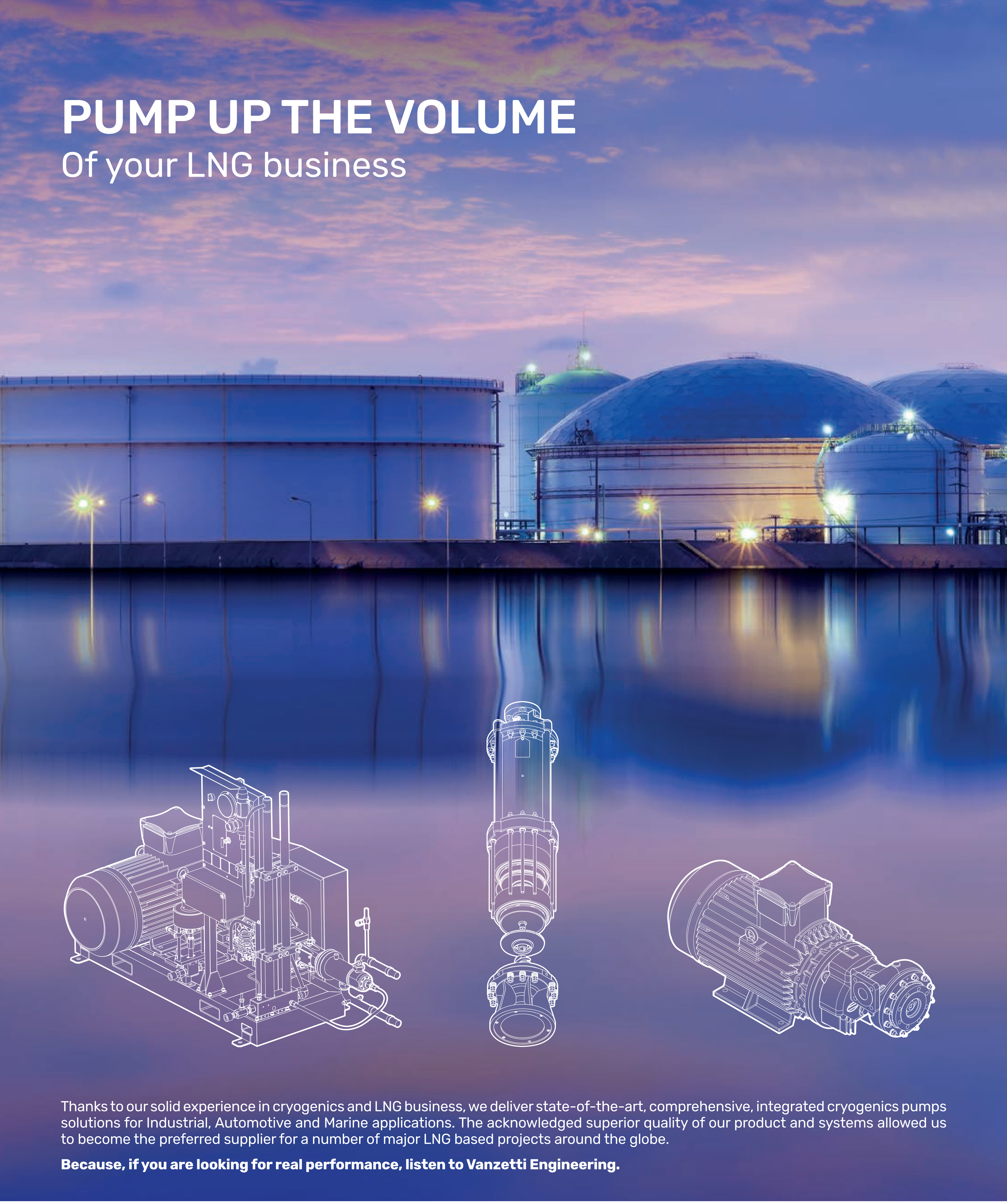
They would also set a target for developing various LNG regasification and import terminals.

Adani Gas, its subsidiary, is developing compressed natural gas (CNG) stations for the transport sector in India that is interesting for Total, which is already a gas fuel market leader in the US through its stake in California-based Clean Fuel Corp.

As part of the Hazira stake sale to Shell, Total signed an agreement to supply 500,000 tonnes per annum to the Indian market over five years from its global volumes of more than 40 MTPA.

Total has been keen to invest in the gas market in India and finds the Adani Group a suitable vehicle as it owns downstream and midstream infrastructure, including stakes in the West and East Coast LNG terminals.

The East Coast Dhamra terminal when completed will serve city-gas and power projects as well as industrial customers. ■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LNG pioneer Tokyo Gas advances with next phase of development for marketing and procurement

Japanese has the volumes and ships and now adapts strategy for solid future

Tokyo Gas has specified three goals for 2030 as part of the medium-term management strategy with liquefied natural gas at the core as it optimizes stakes in 14 projects in six countries.

The Tokyo Gas LNG portfolio currently amounts to 14 million tonnes per annum and the utility controls a fleet of 10 ships to deliver to its four import terminals in Japan.

Tokyo Gas executives and Vietnamese officials at a joint venture accord signing earlier in 2020

Leadership

The utility company said it would show leadership in the efforts to achieve the "transformation of the LNG value chain, net-zero carbon-dioxide emissions and the establishment of a value co-creation ecosystem.

"With regard to liquefied natural gas (LNG), one of the Group's strengths, we will shift from viewing LNG as a raw material of gas and electricity delivered to our clients to viewing it also as product," said the utility.

"Increasing the flexibility and competitiveness of our procurement portfolio, we will work to expand our LNG operations through asset-backed trading, and through terminal operations that are integrated with overseas LNG demand," said Tokyo Gas.

The company said it would reassess LNG as a product that provides value to customers and would establish a new company to concentrate on LNG trading to ensure agile transactions.

"We will formulate and promote a comprehensive strategy for accommodating LNG supply and demand, and upgrade operational functions for gas and power source procurement, LNG transactions and so on by establishing a new Asset Optimization & Trading division," it said.

Measures

Tokyo Gas believed all these measures would create a more flexible and competitive LNG procurement portfolio.

"As LNG demand continues to increase worldwide, we will optimize LNG supply and demand by utilizing the Tokyo Gas Group assets and deepening cooperation with other companies in order to expand both transaction volumes and profits," it explained. Tokyo Gas said it would deepen cooperation with two specific European energy companies and utilities, Centrica plc of the UK and RWE of Germany.

"Along with bother business partners, this cooperation would provide flexibility with respect to procurement and sales contracts and the expansion of LNG swap transactions that utilize ships, LNG terminals, thermal power plants and other assets," said the company.

Working with business partners, the company would use digital technologies to achieve an optimal combination of the strengths of existing assets in the LNG value chain such as LNG transactions, LNG ships, receiving terminals and so on to expand transaction volumes.

"In addition, we will expand demand by providing shipping and other operations that constitute our strengths as an added value for LNG transactions," it said.

"We will also reduce costs by increasing LNG transport efficiency through location swap, using the Tokyo Gas fleet and destination-free project LNG," added the company.

Objectives

Tokyo Gas said it would pursue its objectives both nationally and globally by being more competitive in offering gas, electricity and services through efficiency measures with costs set to fall by 30 billion yen ($277 million)

"In the electricity segment, we will balance sales promotion with measures to increase efficiency," it added.

Tokyo will aim to have a secure customer base of 12 million for natural gas and 2.4M for electricity and a pipeline gas network of 60,000 kilometres.

"In the services segment, we will expand them using skills and expertise in the areas of engineering, real estate and liquid gas,' explained the company.

Combination

"The combination of the three efforts will enable us to collaborate with business partners to respond to customer needs over a wider area that is not limited to the Tokyo metropolitan area," it stated.

Tokyo Gas explained that through these activities it would continue with the promotion and expansion of natural gas to help with current decarbonization efforts. "In addition, preparing for the net-zero CO2 emissions society in the future, we will acquire renewable power resources and commence a new energy services that combine natural gas and renewable energies," explained the company.

"We will also to innovate new technologies such as hydrogen production," it said.

Gas operations

Tokyo Gas said that the strategy would likely result in fiscal year 2022 profits amounting to around 140Bln yen ($1.30Bln).

The company also noted that the restructuring of the natural gas and energy business in Japan had not yet ended.

"There will be increased privatization of publicly-owned gas operations (Sendai City Gas, etc.), and with the likelihood of increased competition and LNG oversupply, legal unbundling may provide an opportunity for industry restructuring," said the utility.

Tokyo Gas said that its future energy and solutions would not be limited to the

> *Without causing any inconvenience to our customers, we will smoothly proceed with the legal unbundling of the Pipeline Network Division in April 2022*

Tokyo metropolitan area and it also planned to improve pipeline connections.

"Without causing any inconvenience to our customers, we will smoothly proceed with the legal unbundling of the Pipeline Network Division in April 2022, and will continue to strive to ensure stable supply and safety," it added.

Additionally, the shift to renewable energies and the introduction of distributed energy systems would progress further due to the revision of the Electricity Business Act in Japan and the establishment of new types of electric power markets.

Tokyo Gas will also proceed with the establishment a second brand called Hinatao Energy Co., which has just been launch in March 2020.

Hinatao Energy would especially cater for internet sales of electricity and gas in order to provide a menu of various services that can meet the wide-ranging needs of primarily digitally-oriented customers.

European links

In addition to its European links with Centrica and RWE it also works closely with two Japanese utilities, Kansai Electric Power and Kyushu Electric Power.

Tokyo Gas like another Japanese utility, Osaka Gas, plans to expand in the Asian region.

"Using our accumulated LNG strengths and achievements, we will focus on LNG infrastructure business development in Asia where the demand for natural gas is increasing," said Tokyo Gas.

"We will also work to expand the scale of renewable power generation and increase the value of natural resource development business," it added.

The company expects to find new LNG demand pockets and develop new LNG terminals in an integrated manner.

"We will participate in LNG infrastructure studies to discover and develop new projects in each country from the master plan stage," said Tokyo Gas.

"We will conduct the integrated development of LNG terminals and gas power generation business, utilizing the strengths and achievements of LNG user's know-how cultivated in the course of conducting domestic gas operations," it added.

It noted two particular projects, its cooperation with Petrovietnam Power Corp., the largest such operator in Vietnam, to promote the development of LNG-to-power projects.

Tokyo Gas is also working with First Gen, the largest natural gas user in the Philippines and a power generation company of the Lopez Group, to construct and operate LNG receiving terminals.

Subsidiary Tokyo Gas Engineering Solutions has also signed a deal to provide Project Management Contract services for the construction of an LNG receiving terminal at Nong Fab in Thailand. ■

For the Record

ABB, the Swiss-Swedish company, said it was chosen to provide the electric propulsion and power distribution package for Southeast Asia's first liquefied natural gas hybrid tug ordered to operate in the Port of Singapore. ABB said its equipment, including energy storage, control and automation technology will be at the heart of the first tug capable of switching between low-emission LNG engines and zero-emission battery power. The tug, which will operate in Singapore harbour, has been ordered by Sembcorp Marine subsidiary Jurong Marine Services for delivery from the Singapore shipyard by the end of 2020.

LNG as a fuel virtually eliminates sulphur-oxide emissions, while the Maritime Port Authority of Singapore (MPA) is also incentivizing its use to support the International Maritime Organization's aims to halve ship carbon-dioxide emissions in the years ahead. ABB said the project represents the first delivery of ABB's award-winning power and distribution system, the Onboard DC Grid, for a tug application. Leveraging the system, the vessel will be able to deploy 904 kilowatt hours of battery power for zero-emission operations, as well as for peak shaving, improving utilization of electricity use on board. "This is a breakthrough in the tug market for the ABB's energy storage technologies and a strong validation of Onboard DC Grid™ as the ultimate solution for power management efficiency for hybrid propulsion," said Juha Koskela, Managing Director of ABB Marine & Ports. "Future-proofing for a different energy mix makes particular sense for tugs and other port service vessels, as the most likely candidates to face imminent environmental restriction, added Koskela. "This is also a great example of a local team meeting a regional priority," he stated.

ABB noted that gas-fueled engines face a particular challenge when it comes to handling the fast-changing load capabilities demanded by tugs. "Leveraging the Onboard DC Grid system, the tug's engines will be able to run at variable speeds for optimized LNG fuel economy at each load level," said the company. "Additionally, through integration with an energy storage source, the batteries will be able to provide power to the tug's propulsion system almost instantaneously," added ABB.

ANNOVA LNG, the medium-scale US project planned for the south bank of the Brownsville Ship Channel in Texas, and whose owners include Chicago-based power company Exelon Corp., has received one of its final permits to begin construction. The permit granted by the Texas Commission on Environmental Quality (TCEQ) was a clean air permit. The Annova project is expected to ship around 6.95 million tonnes per annum from its proposed liquefaction and plant planed as part of the second wave build-out for exports.

The joint venture proposes the construction of six small-scale liquefaction Trains as well as an interconnected pipeline and marine export facilities. "Annova LNG is taking extensive steps to minimize air emissions as part of our commitment to achieve the lowest carbon footprint per pound of production among all US LNG providers," said Omar Khayum, Annova LNG Chief Executive. "In addition to contracting for the use of 100 percent carbon-free renewable energy to power our electric-driven compressors, we will minimize venting and flaring by recovering air emissions from the liquefaction process," added the CEO. Annova LNG is considered a "minor source" of air emissions, according to the TCEQ and Environmental Protection Agency review regulations. The project's investment-grade equity owners, including Exelon, are Black & Veatch Corp. of Kansas and Kiewit Corp. of Nebraska. Annova is one of three LNG plants planned for the Port of Brownsville and comprise multiple liquefaction Trains and around 37 MTPA output.

The other two projects include the Rio Grande venture of NextDecade Corp., with 27 MTPA of output, and the smaller scale Texas LNG venture. Annova's strategy is to offer volumes to mid-scale customers who are seeking to buy increments of 1.0 MTPA. The facility's air emissions are designed to be well below applicable air quality regulations, ambient air quality standards and health effects review criteria. "The issuance of this TCEQ permit keeps us on track to construct and operate the most sustainable and reliable LNG in the United States," stated CEO Khayum. Annova LNG currently plans to commence construction in 2021, to commission the plant in 2024, while commercial operations are set for early 2025. The facility has received key federal authorizations, including its FERC certificate authorization and Department of Energy approval to export its full capacity to both Free Trade Agreement and non-Free Trade Agreement nations. Annova also signed an accord in January 2020 to arrange feed-gas deliveries from the Agua Dulce hub in Texas. Its agreement with Enbridge Inc. affiliate, the Valley Crossing Pipeline (VCP), will provide transportation for its total feed-gas requirements. Annova investors Black & Veatch and Kiewit were also jointly awarded the engineering, procurement and construction contract.

ARROW ENERGY, the Australian joint venture between Royal Dutch Shell and PetroChina, has taken a final investment decision to develop the first phase of Arrow's Surat Gas project in the state of Queensland to line up more LNG exports for China. The decision will bring up to 90 billion cubic feet per year of new coal-seam gas to market at peak production, which will flow to the Shell-operated Queensland Curtis LNG export plant, one of three facilities on Curtis Island near the port of Gladstone. The Arrow resources are the largest uncontracted reserves of CSG on the East Coast and the initial developments costs are expected to be around US$6.5 billion.

Arrow was acquired by a 50-50 joint venture partnership of Shell and PetroChina in 2011 and de-listed from the Australian Securities Exchange. It was expected to develop a two-Train stand-alone LNG export plant until Shell acquired BG Group of the UK in 2015 and the ready-made QCLNG project. In addition to the QCLNG plant, the other two facilities on Curtis island are Australia-Pacific LNG and Gladstone LNG. The ConocoPhillips-operated APLNG plant has China's Sinopec as one of its shareholders and largest buyer, while QCLNG already supplies China National Offshore Oil Corp. and will now likely ship to PetroChina terminals as well. "The decisions by PetroChina, Shell and Arrow demonstrate commitment to and confidence in Queensland and the Australian market at a time of global economic turmoil from Covid-19 and against the backdrop of sustained low oil prices," said Arrow Chief Executive Cecile Wake. "This significant investment comes at a critical time and will cement Arrow's position as a major producer of natural gas on the East Coast," she added. "The Surat Gas Project is the first large-scale CSG project in Australia to be underpinned by a significant infrastructure collaboration and gas sales agreement, together with a suite of supporting agreements, which have been put in place between Arrow and the Shell-operated QGC joint venture," explained the Arrow CEO. Wake said Arrow would this year commence construction of more than 600 phase-one CSG wells. Over the full 27-year life of the Surat Gas Project, Arrow expects to develop around 5 trillion cubic feet of natural gas.

Maarten Wetselaar, Integrated Gas and New Energies Director at Shell, said the utilisation of QGC's existing upstream pipelines and treatment facilities enables Arrow to significantly reduce development costs. "The Arrow joint venture partners' decision not to build another two Trains on Curtis Island provided the opportunity to create this alternative pathway to market for the resource," explained Wetselaar. "The approach we have taken to this investment is aligned with Shell's focus on actively managing all operational and financial levers to deliver sustainable cash flow generation," he added. "It reflects our disciplined approach to capital spend, which takes a long-term view of the fundamentals of supply and demand," stated Wetselaar. Shell Australia Chairman Tony Nunan stated that QGC had reached strong and stable production since its start up in December 2015, and Arrow has the strong technical capability to develop the Surat Basin fields. "QGC supplied 16 percent of the demand in the Australian east coast domestic gas market in 2019 and celebrated its 500th LNG cargo," added Nunan. "Gas from Arrow will provide more supply to both Australian domestic customers and export markets," he said. Construction of the project will commence in 2020, with first gas sales expected in 2021.

BHP, the Anglo-Australian global commodities and energy company with long-standing stakes in Western Australian LNG, natural gas and mining and with LNG-powered shipping plans, said it planned to hire 1,500 additional people to support its workforce operating across Australia. BHP, a foundation investor in Australia's first export plant, the North West Shelf project that came on stream in 1989 and the latest project, the Woodside-operated Burrup Hub gas venture, said 1,500 jobs would be offered as six-month contracts with prospects of full-time work. The jobs in four Australian states cover a range of skills needed by BHP operations in the short term. "These jobs will support and bolster our existing workforce during this difficult time," said the company. BHP is offering positions for machinery and production operators, truck and ancillary equipment drivers, excavator operators, diesel mechanics boilermakers, trades assistants, electricians and cleaners. It is also offering warehousing roles across its coal, iron ore and copper operations in Western Australia, Queensland, New South Wales and South Australia. "Following the initial six-month contract, BHP will look to offer permanent roles for some of these jobs. BHP will continue to assess this program and may increase the number of jobs available," it stated.

In addition to its LNG and gas stakes in Western Australia, BHP is one of the main shippers of bulk commodities to Asian nations such as China. It issued a tender in late 2019 for the world's first LNG-powered bulk carriers, with the possibility of 12 such vessels being ordered for the transport of 27 million tonnes of its iron ore from Australia to North Asia. These ships will be able to transport the equivalent of about 10 percent of BHP's iron ore sales. BHP Acting Minerals Australia President Edgar Basto said the jobs offer was a way of "supporting our people, communities and partners." "As part of BHP's social-distancing measures we are introducing more small teams with critical skills to work dynamically across different shifts," he said in relation to moves to contain the coronavirus.

"The Government has said that resources industry is vital in Australia's response to the global pandemic," added Basto. "We are stepping up and providing jobs and contracts. Our suppliers, large and small, play a critical role in supporting our operations," he explained. "It is a tough time for our communities and the economy. We must look out for each other as we manage through this together," stated the BHP executive.

BP has issued a "force majeure" notice to a subsidiary of Golar LNG relating to the delivery of a floating LNG production hull, the "Gimi", for a start-up date in 2022 for the Greater Tortue Ahmeyim project offshore Mauritania and Senegal. Golar's FLNG company set up for the BP project, Gimi MS Corp., said it received written notification of the "force majeure" from BP Mauritania Investments Ltd. "The notice received from BP claims that due to the recent outbreak of the novel coronavirus (Covid-19) around the globe, BP is not able to be ready to receive the floating liquefied natural gas facility "Gimi" on the target connection date," said Golar. BP estimates at this stage that the consequential delay caused by the claimed "force majeure" event is in the order of one year and that it was not currently possible to mitigate or shorten this delay. A company can claim "force majeure" on a contract when it can prove "unforeseeable circumstances" had prevented it from fulfilling its side of a bargain, which in this case is keeping to the development timetable of the project. "Golar has asked BP to clarify how a 'force majeure' event discovered as recently as the end of March 2020 could immediately impact the schedule by an estimated one year," stated Golar. "Based on the information received the company is engaging in clarification and an active dialogue with BP to establish the duration of the delay and the extent to which this has been caused by the claimed 'force majeure' event.," explained Golar.

The vessel "Gimi" is a former conventional LNG carrier that is being converted into a floating production hull with an on board liquefaction plant. Bermuda-based Golar added that in anticipation of a potential delay, it had commenced discussions with its main ship-building contractor for the project, the Keppel Shipyard in Singapore, to re-schedule activities in order to reduce and reprofile its capital-spending commitments for 2020 and 2021. "The company is evaluating the notice and reserves all of its rights under the agreement," said Golar.

CENTRICA, the UK utility and energy company with a growing LNG market presence including booked volumes from the US and Mozambique, has confirmed Chris O'Shea in his post of Chief Executive. O'Shea, the former Chief Financial Officer, had initially been named as interim CEO on March 17 while a search got underway for a permanent successor to Iain Conn, who had stepped down as scheduled as CEO and from the Board. A new Chairman, Scott Wheway, had also been named in March when incumbent Chairman Charles Berry, who has been on medical leave since the 12th of February 2020, tendered his resignation for health reasons. Centrica, owner of the utility company British Gas, has established strong LNG capabilities over the past few years, including having a cooperation agreement with Japanese utility Tokyo Gas.

Centrica and Tokyo Gas have co-purchased offtake of delivered ex-ship (DES) supplies amounting to 2.6 million tonnes per annum for 20 years from the proposed Total-led Mozambique LNG export plant in southeast Africa. Centrica additionally has a 20-year contract for volumes from Train 5 at Sabine Pass on a free-on-board (FOB) basis, giving it destination rights for the cargoes and a purchase price indexed to the US benchmark Henry Hub price. The UK company holds regasification capacity at Europe's largest import terminal, the Isle of Grain facility on the River Medway-Thames estuary in Kent. In addition, LNG fleet owner GasLog recently received a newbuild carrier that will be chartered to Centrica for its growing LNG activities.

The 180,000 cubic metres capacity vessel, named "GasLog Windsor", was constructed at Samsung Heavy Industries on South Korea. "In the last few weeks since my appointment I have completed a review of both the internal and external candidates for this role and have come to the conclusion that Chris is comprehensively the best candidate for Centrica," said Chairman Wheyway in making the announcement. "I'm delighted to appoint him to the role on a permanent basis," he added. "The Board is confident that he is the right leader to navigate Centrica through and beyond the present Covid-19 crisis focusing on the welfare of our colleagues and customers, the financial resilience of the company and the agility to move quickly when we emerge from these unprecedented circumstances," said the Chairman.

O'Shea said it was a huge honour to be appointed to lead Centrica. "The company has a long history of serving customers and having strong market positions. Over recent years it has built the capabilities to help our customers transition to a low carbon future," he added. "Beyond this present emergency our focus will be on creating value for all of our stakeholders through delivering growth in our customer-facing businesses, the structural simplification of the group, and building on the undoubted strengths and capabilities we have in our people and our businesses today," stated the CEO. O'Shea's remuneration package will consist of a basic salary and variable incentive arrangements. The key changes to his current arrangements are a base salary of £775,000 ($974,200) and a reduction from a 15 percent to 10 percent pension contribution. The company has commenced a search for a new CFO since O'Shea won't be returning to the post.

CNOOC, or China National Offshore Oil Corp. the state-backed oil and gas producer and the nation's largest LNG import terminal owner, said annual net profits rose almost 16 percent as it achieved record production in 2019. "Total net oil and gas production of the company amounted to 506.5 million barrels of oil equivalent, exceeding 500 million Boe for the first time as multiple projects safely commenced production ahead of schedule," said CNOOC. CNOOC said net profits rose by 15.9 percent to 61.05 billion Chinese yuan ($8.6Bln) compared with 52.67Bln yuan ($7.42Bln) because of volume growth and effective cost control. In relation to the changed oil market and the plunge in prices, along with other challenges in 2020, CNOOC said it would keep a close watch on events.

"CNOOC will closely monitor the trend of the international crude oil markets and changes in the macroeconomic environment," said the company.

"It will conduct in-depth research, timely formulate and take counter-measures and strive to maximize shareholder value," it added.

Its marketing revenues, including LNG imports at its nine regasfication terminals, dropped 13.9 percent to 30.86Bln yuan ($4.34Bln) compared with 35.83Bln yuan ($5.05Bln) in 2018.

The company said its average realized oil price was US$63.34 per barrel, down 5.8 percent year-over-year. CNOOC's annual natural gas production rose 5.2 percent to 561.3 billion cubic feet. The average realized natural gas price was US$6.27 per thousand cubic feet, down 2.2 percent from the previous year. CNOOC's oil and gas sales revenue reached 197.2 billion yuan ($27.2Bln), an increase of 5.7 percent compared with 2018. The company said that last year it had continued to strengthen its exploration and development efforts, and the workload reached a record high.

Beijing-based CNOOC, which is listed on the Hong Kong Stock Exchange, said that during the year there were 23 commercial discoveries made and 30 oil and gas bearing structures were successfully appraised. "The appraisal of Bozhong 19-6 condensate gas fields in offshore China made a breakthrough again, with newly-added proved in-place volume of nearly 200 million cubic metres of oil equivalent," explained the company. CNOOC also made progress in its overseas exploration and production activities. "Five new discoveries were made in Stabroek block in Guyana, with aggregate recoverable resources of more than 8 billion Boe," said CNOOC. The company said its reserve replacement ratio for the year reached 144 percent and the reserve life remained stable at a level above 10 years, which further strengthened the resource foundation for the future development. "As at the end of 2019, the net proved reserves of the company exceeded 5 billion Boe in total," added CNOOC. "In the future, we will continue to focus on our own development, implement more stringent cost controls and more prudent investment decisions, strengthen cash flow management and maintain the company's long-term sustainable development," said Chairman Wang Dongjin. The company said annual capital expenditure came to 79.6Bln yuan ($11.2Bln), which fully supported the exploration and development activities. The CNOOC Board said it proposed a final dividend of HK$0.45 per share (US$0.06) on a tax inclusive basis.

COMMONWEALTH LNG project in the US, a liquefaction and export plant proposed for the west side of the Calcasieu Ship Channel near Johnson Bayou in Louisiana, has had its revue schedule suspended by regulators to let the company catch up with the process. The Louisiana project already has cooperation and supply agreements with global commodities firm Gunvor. The Federal Energy Regulatory Commission said it was suspending the environmental review schedule for Commonwealth LNG's proposed export plant in Cameron Parish.

"The notice of schedule, issued on October 15, 2019, identified a May 2020 draft Environmental Impact Statement (EIS) issuance date and an October 2, 2020 final EIS issuance date," explained the FERC. "This schedule was based upon Commonwealth providing complete and timely responses to any data requests," added the Commissioners. "In its February 4, 2020 partial response to staff's January 2, 2020 data request, Commonwealth stated it would provide the remainder of the outstanding responses in stages through July 2020, including an official interpretation from the United States Department of Transportation - Pipeline and Hazardous Material Safety Administration (PHMSA) in June 2020 pertaining to. Commonwealth's proposed LNG storage tank design," said the FERC statement. "Because the outstanding data responses to staff's data request and the issuance of the PHMSA interpretation are expected after the previously announced draft EIS date, the Commission will suspend the environmental review schedule for the project," stated the FERC.

The Commonwealth plant will have a total liquefaction capacity of 8.4 MTPA and LNG storage capacity volumes of 240,000 cubic metres and has chosen a modular construction format. Commonwealth and Swiss-based Gunvor have entered into a strategic LNG marketing and supply agreement whereby Gunvor will support Commonwealth in securing binding LNG offtake deals for the full capacity of the facility. In addition, Gunvor will commit to take up to 3 million tonnes per annum of LNG offtake from the US plant. Commonwealth had in June 2019 signed a preliminary supply deal with Gunvor. The FERC outlined the next steps for Commonwealth to continue proceeding in the regulatory process. "Once staff has reviewed both the responses and the PHMSA interpretation, the Commission will issue a revised schedule for the draft and final EIS," it said. "This is not a suspension of the Commission staff's review of Commonwealth's project. Staff will continue to process Commonwealth's proposal to the extent possible based upon the information Commonwealth has filed to date while awaiting the responses and the PHMSA interpretation," it added.

DOMINION Energy closed its acquisition of Pivotal LNG from the utility, Southern Company, to enter the small-scale market for deliveries by containers, trucks and to be a supplier to the maritime fuel market. With completion of the transaction, Dominion assumed 100 percent ownership of Pivotal's small LNG liquefaction plant in Trussville in Alabama and takes 50 percent ownership of the Jax LNG facility in Jacksonville, Florida. Houston-based NorthStar Midstream owns the remaining 50 percent of Jax. It is the first small-scale LNG plant in the US with the capability to provide fuel for LNG-powered ships and to enable truck deliveries.

With the Trussville plant and the Jax facility there is capacity to produce 180,000 gallons of LNG a day and to store 7 million gallons of the fuel. The Jax LNG facility has the space to expand production capacity by an additional 480,000 gallons per day to meet growing demand. "The acquisition of Pivotal LNG will play an important role in our broader strategy to help decarbonize the marine shipping industry," said Roger Williams, Dominion Energy's Vice President of Gas Development Services. "Pivotal and our existing Cove Point LNG facility in Maryland positions us well to lead the transformation of the marine industry and to serve other growing LNG markets along the East Coast," added Williams.

The maritime sector is increasingly moving to LNG as a fuel to reduce emissions and comply with the new regulations of the International Maritime Organization. The Jax plant is able to supply LNG-fueled container and cargo ships for US shipping lines engaged in Jones Act trade between Florida and the US territory of Puerto Rico. The facility has a specially built LNG bunkering barge called "Clean Jacksonville". Dominion Energy' Cove Point LNG facility on Chesapeake Bay in Maryland began exporting LNG in 2018 to Japan and India. The liquefaction facility has a nameplate capacity of 5.25 million tonnes per annum and 20-year tolling agreements with Japanese trading house Sumitomo Corp. and partner Tokyo Gas and Indian state-owned gas utility Gas Authority of India. Cove Point LNG also owns a 136-mile pipeline connecting the plant to the interstate pipeline system. Dominion itself is also developing its domestic power and gas businesses across America and has more than 7 million customers in 18 states.

ENN ENERGY Holdings, the Chinese city-gas company and owner of the Zhoushan LNG import terminal in eastern Zhejiang province, reported a jump in annual profits and increased retail gas sales. ENN posted annual revenues of 70.18 billion yuan (US$9.9Bln) a 15.6 percent increase on the 60.69Bln yuan US$8.58Bln) of income recorded in the previous year. "The increase was mainly driven by the robust growth of natural gas sales, the integrated energy business and value added activities," said ENN. The company said its profits from pipeline natural gas, city-gas supplies and a growing gas-fuel business for vehicles increased by 18 percent to 5.27Bln yuan (US$746 million) from 4.47Bln (US$632M) during the year. ENN, which is listed on the Hong Kong stock exchange, said profits attributable to owners of the company doubled to 5.6Bln yuan (US$802 million) from 2.81Bln yuan (US$398M) the previous year. "The surge in net profit was attributable to the strong growth of the group's core businesses mentioned above and the improvement of its operating efficiency," explained ENN. "In addition to that, oil price movements also led to a large fair value change of the derivative contracts which were used to hedge the group's long-term liquefied natural gas contracts," it added.

ENN's retail natural gas sales volumes rose 14.7 percent in the year to 19.92 Bcm cubic metres, the equivalent of almost 15 million tonnes of LNG, from 17.37 Bcm the previous year. At year-end ENN had a total of 217 city-gas franchises spanning 22 provinces and added 30 more during the year. "The Group upheld its customer-oriented philosophy, dug deep into the existing customer base and explored new customers with potential demand," said ENN. "Most of the ENN's franchises are located in key areas of air pollution prevention and control, including Beijing-Tianjin-Hebei, Henan, Shandong, Jiangsu, Zhejiang, Guangdong, where local governments strictly implement environmental protection policies," it explained.

ENN said it took advantage of strategic positioning of its Zhoushan LNG import terminal to expand its wholesale and retail gas businesses. "We distributed LNG to downstream customers such as small-scale gas distributors and retail gas users outside its city-gas concessions, to LNG refuelling stations and to power plants," added ENN. The company said that its final dividend per ordinary share would be 43.3 percent higher than the previous year at HK$1.67 (US$0.21) versus HK$1.19 (US$0.15) in 2018. "The Group's business continued to grow steadily in 2019 as the Chinese government's determination to push forward 'coal-to-gas' conversion for pollution control and to promote natural gas as one of the main energy sources remained firm," stated ENN. ENN said that to cope with the challenges of the upstream gas price hike and the slowdown in economic growth, the group had collected and analysed customer energy consumption data through the established of an intelligent operations platform. "The Group also provided discount to customers with stable and large gas consumption volumes, and those with peak-shaving or interruptible gas needs, in an attempt to continue expanding gas sales volume while supplying gas stability and safely," it explained. The "ENN Smart Energy" APP was also launched during the year and enabled city-gas customers to be provided with accessible and convenient online services.

EXMAR, the Belgian shipping and projects company with more than 40 vessels in its fleet and now mostly focused on the liquefied petroleum gas business and LNG shipment management, said the Bank of China had finally released financing for the "Tango FLNG" production barge deployed in Argentina while the vessel itself was earning income as it liquefied shale gas from the Vaca Meurta Basin. The outbreak of the coronavirus in China had previous delayed the release by the Bank of China of $40 million under the "Tango FLNG" loan facility. The "Tango FLNG" production barge project can liquefy around 500,000 tonnes per annum of LNG for domestic sale or export and has so far produced four cargoes and shipped them to buyers.

"The relaxation of the cash collateral follows the steady operational results of the 'Tango FLNG' since September 2019, under the 10-years charter with YPF S.A of Argentina," said Exmar. "The amount of $40 million has been partially allocated to the repayment of the bridge loans and to cover Exmar's capital commitments," it added. "Exmar has also obtained and drawn under a pre-delivery financing of $20 million with Maritime Asset Partners in December 2019, which partially covers the instalments paid during the construction of the two Very Large Gas Carriers (VLGCs) under construction," said the Antwerp-based company. Exmar, which has undergone financial troubles over the past couple of years, said in its earnings report just published that turnover increased and amounted to $136.7 million in 2019 compared with $87.7M in the previous year.

Gross earnings were $47.3M versus $27.5M the previous year, while annual net losses widened slightly to $26M from $22M in 2019. Exmar is led by Chief Executive Nicolas Saverys and also continues to manage 10 LNG floating storage and regasification units, though is not directly involved in regasification projects with former partner Excelerate Energy of the US. The "Tango FLNG" vessel is exporting from the port of Bahia Blanca where it produces LNG from pipeline feed-gas from the onshore Vaca Muerta Shale Basin. "Some 475,000 cubic metres of LNG have been delivered, already resulting in four shipments by YPF. 'Tango FLNG" is performing above expectations, clearly demonstrating Exmar's expertise in the field of liquefaction," said the company.

The vessel was built at the Chinese Wison shipyard in Nantong and delivered to Exmar in 2017. It had initially been destined for a project in Colombia in South America that was cancelled. The vessel formally started its operations in mid-2019 and a 10-year charter term began in September 2019. Exmar said in its latest financial update that it had "sufficient liquidity to meets its present obligations and cover its working capital needs for a period of at least 12 months" from the authorization date of the annual report.

EXXONMOBIL confirmed it was delaying a final investment decision for the Rovuma liquefied natural gas project in Mozambique, probably into 2021 at the earliest, but US Gulf Coast spending plans remain on track. The FID had been expected for later in 2020, though the US major said it was continuing to actively work with its partners and the government to optimize development plans. The Coral LNG development continues offshore Mozambique continues as planned. The Mozambique update came in a statement from ExxonMobil saying it was reducing its 2020 capital spending by 30 percent and lowering cash operating expenses by 15 percent in response to low commodity prices resulting from oversupply and demand weakness from the Covid-19 pandemic.

"Capital investments for 2020 are now expected to be about $23 billion, down from the previously announced $33Bln," said ExxonMobil. The 15 percent decrease in cash operating expenses is driven by deliberate actions to increase efficiencies and reduce costs, and includes expected lower energy costs. "Despite the reductions, ExxonMobil expects to meet its projected investment of $20Bln on US Gulf Coast manufacturing facilities made in its 2017 'Growing the Gulf' initiative," said the US major. This spending is mainly on refining and chemical-manufacturing projects. The company also expects to reach its proposed US investment of $50 billion over five years announced in 2018," it added.

ExxonMobil said in October 2019 that it planned to invest more than $500M in the initial construction phase of its Rovuma project in Mozambique as part of the Area 4 resources development with its partners, including Italian energy company Eni and China National Petroleum Corp. "After a thorough evaluation of the impacts of the pandemic and market conditions, we have worked closely with business partners to plan and execute capital adjustments that preserve long-term value, maximize cost efficiency, and put us in the strongest position when market conditions improve," said Darren Woods, Chairman and Chief Executive of ExxonMobil. "The long-term fundamentals that underpin the company's business plans have not changed - population and energy demand will grow, and the economy will rebound," Woods added. Exxon's Rovuma Basin stake, jointly held with Italian firm Eni, will produce LNG from three feed-gas reservoirs located in the Area 4 block offshore Mozambique's northern coast. ExxonMobil is the lead company for the Mamba gas fields and LNG project development and costs are estimated at around $30Bln. Area 4's consortium is formed by Mozambique Rovuma Ventures, comprising ExxonMobil with 25 percent, Eni with 25 percent and China's CNPC, also known as PetroChina, with 20 percent. The remaining 30 percent of shares in that licence are held in parcels of 10 percent by South Korean utility and energy company Korea Gas Corp., Galp Energia of Portugal and Mozambique's state energy company ENH.

HEEREMA Group, the Dutch marine offshore contractor and owner of the biggest and strongest semi-submersible crane ever built, the "Sleipnir", said the vessel has received the world's largest ever LNG bunkering load in the Port of Rotterdam. Four Dutch companies cooperated in the achievement, Heerema, Titan LNG, which used fuel from the 10,000 cubic metres capacity small-scale carrier "Coral Fraseri", owned by shipping line Anthony Veder, and the Port of Rotterdam company. "This was a collaboration of four Dutch innovative companies who have united to make history for sustainability in The Netherlands," said a statement. The total quantity of LNG delivered into the fuel tanks was almost 3,300 metric tonnes, making this the largest LNG bunkering to have ever taken place.

The delivery took less then 24 hours to complete for the dual-fuel "Sleipner" which can be powered with LNG or Marine Gasoil. The "Sleipnir" had arrived at the Port of Rotterdam on March 22 after operations in various parts of the world. The vessel, which was built in Singapore and received LNG in a ship-to-ship transfer in July 2019 about 12 miles off the coast of Indonesia from the same small-scale carrier "Coral Fraseri". Heerema Chief Executive Koos-Jan van Brouwershaven said his company was proud of the LNG bunkering record. "We are especially pleased that this achievement could take place in our home base of the Port of Rotterdam," added Van Brouwershaven. "The use of LNG on 'Sleipnir' is one of many sustainability measures we have introduced, and we will continue to investigate ways to reduce our impact on the planet," added the Heerema CEO.

Niels den Nijs, CEO of Titan LNG, said that LNG bunkering was becoming a routine operation for the Dutch companies involved because of the excellent cooperation between all parties. "'Building on our five previous deliveries around the globe, we formulated and safely executed our plan of operation," he explained. "As Titan LNG, we are proud of this operation in one of our home ports. It was extra special that we could also supply our bunker barge, the 'FlexFueler 001', with cargo from the LNG carrier," he added. Jan Valkier, CEO of Anthony Veder, commented: "By investing in dedicated LNG vessels since 2009, we have made an essential contribution to the availability of LNG for the power generation and LNG as a marine fuel." Allard Castelein, CEO of the Port of Rotterdam Authority, said it was the port's ambition to become the greenest in the world. "I am proud that the vessel bunkered in the Port of Rotterdam because that pays tribute to Rotterdam being the ideal LNG hub for imports, exports, storage and bunkering," stated Castelein. The four companies noted that they followed all coronavirus health and safety guidelines for all involved in the bunkering operation.

JAPANESE liquefied natural gas imports dropped last month and the nation's cargo costs fell along with lower LNG prices while thermal coal deliveries were preferred for power generation. Japan imported 6.64 million tonnes of LNG in February 2020, down 9.6 percent from the 7.35MT received in February 2019. The Japanese had imported 7.51MT in January 2020, down 0.5 percent from the 7.54MT received in January 2019. The shipments cost the nation 351.42 billion yen ($3.26Bln), 24 percent lower in yen terms than the import bill for February 2019 when it was $462.22Bln yen ($4.13Bln), according to the preliminary figures from the Japanese Finance Ministry.

Thermal coal imports, a major replacement for LNG in the power sector, came to 9.14MT in February 2020, down just 1.6 percent on the 2019 figure and in line with the January 2020 shipments. The country's imports of LNG fell for the whole of last year to 77.32MT, which was 6.7 percent lower than the 82.85MT of shipments that arrived in 2018. The costs of cargoes sent to Japan amounted to 4,354 billion yen ($39.72Bln) in 2019, down 8.1 percent from the previous year. Annual thermal coal shipments came to 111.05MT in 2019, down just 2.2 percent on the 2018 total. Asian LNG cargo deliveries from nations such as Malaysia and Indonesia, Papua New Guinea and Brunei amounted to 1.66MT in February 2020, down 18.7 percent on the same month a year ago.

Middle East deliveries from countries like Qatar, the United Arab Emirates and Oman came to 1.31MT, a drop of 15.1 percent. Shipments from Russia, mostly from the Sakhalin Island plant in the Far East, amounted 597,000 tonnes, a decline of 1.1 percent on the same month last year. US cargo deliveries to Japan continue to rise as more capacity comes on stream and came to 473,000 tonnes versus 403,000 tonnes in January 2020, and 41.2 percent higher than the 335,000 tonnes received in February 2019. Japan will be importing a bigger proportion of low-priced US cargoes in the years ahead from booked volumes and the spot market with six US export plants now in operation. Last year the US shipped 3.69MT to Japan, a rise of 48.2 percent on 2018. The balance of Japan's January imports came from Australia, African nations and the spot market and amounted to 2.60MT versus 2.83MT in February 2019 and 3.22MT in January 2020.

MAGNOLIA LNG project owner LNG Ltd of Australia said a takeover bid by a Singapore-based private company had been withdrawn. LNG Ltd, which is also developing the Bear Head LNG project in the Canadian province of Nova Scotia, said the Singapore firm, LNG-9 PTE Ltd, believes that recent events, including funding problems at LNGL, had affected its plans. LNGL's proposed Magnolia plant near Lake Charles has an accord to supply a $4-billion power project on the Mekong Delta in Vietnam. "The failure of First Wall Street Capital Corp. to provide funding under the legally binding Secured Convertible Note Subscription Deed (announced by LNGL on 27 March) are reasonably likely to have a material adverse effect on LNGL and that certain conditions under its proposed takeover bid have been triggered or are incapable of being satisfied.," said a statement. "In light of the above circumstances, LNG-9 PTE Ltd has notified LNGL that it does not intend to despatch its Bidder's Statement to LNGL shareholders and is therefore withdrawing its takeover bid," it added.

LNGL, which is a small-cap company on the Australian Securities Exchange, said it understood that the Singapore firm remained interested in acquiring all or a material part of LNGL or its assets, and LNGL would continue to work to find a "mutually acceptable transaction" structure. However, LNG-9 PTE Ltd's exclusivity period has lapsed with the retraction of its bid. The Singapore-based bidder had previously told LNGL that it intended to work with the company to provide or arrange new sources of funding to sustain its operations through to at least the end of the offer period. LNGL's Magnolia project has signed a supply agreement with the Vietnamese Bac Lieu import terminal located in the Mekong Delta and scheduled to come on line in 2023. The Magnolia plant would supply 2 million tonnes per annum to the Vietnam terminal.

The Louisiana shipments would be on a free-on-board (FOB) basis for a 20-year term with options to extend the term. LNGL added in the statement on the suspended takeover bid that the company was now working with other parties on strategic alternatives that supplement existing cash on hand to improve LNGL's working capital position and sustain its operations. The company also stated that its wholly owned US subsidiary, LNG Management Services LLC, has received a Paycheck Protection Program (PPP) loan from the United States Small Business Administration (SBA) amounting to US$388,552. "LNGL's existing cash reserves are sufficient to meet all of the company's commitments until May 2020, and LNGL must secure additional meaningful funding urgently to continue operating beyond then," the statement added.

OHGISHIMA City Gas Supply Co., a joint venture between Japan's main LNG importers, has begun commercial operations of a city-gas production and supply facility with a calorific value adjustment system in the Ohgishima district of Kawasaki City. The venture involves JERA Co. Inc., the largest LNG importer, and Osaka Gas and energy firm JXTG Nippon Oil & Energy Corp. The Ohgishima facility with its CVAS equipment will produce about 1.1 million tons of city-gas per annum by mixing natural gas and liquified petroleum gas. The venture is the latest result of the deregulation of Japan's natural gas and electricity markets over the past few years. JERA said it would use the city-gas mainly as fuel for the Shinagawa Thermal Power Station, while JXTG and Osaka Gas would use their shares mainly for city-gas retailing. "JXTG and JERA will also use it as a raw material for hydrogen production at the hydrogen station business in Tokyo's Oi area in which both companies participate," explained JERA in a statement. The city-gas production and processing plant is located between two of the nation's main LNG import terminals, JERAs Higashi-Ohgishima facility and the Ohgishima import terminal owned by Tokyo Gas. JERA will operate the facility and supply its natural gas, JXTG will supply the liquefied petroleum Gas (LPG) used to adjust calorific value, and Osaka Gas will support facility operations based on its expertise in operating similar facilities. "Through OCGS, the partners will manage and operate the facility with safety as their highest priority," they added.

OSAKA GAS, the Japanese utility is advancing its strategy of US shale investments and with world-class LNG supplies backed by a gas-fired power generation model for Japan and Asia. Osaka Gas, whose brand is under the Daigas Group banner, said in its latest strategy update that its proposed Himuka small-scale LNG import terminal planned for the far south of Japan's third-largest island Kyushu was on schedule for start-up in 2022. The Himuka facility will supplying imported LNG to a new gas-fired power plant to replace coal power for chemicals company Asahi Kasei Corp. The Osaka Gas onshore terminals is small-scale and could be replicated elsewhere in Asia.

The simple facilities will comprise the terminal jetty, one LNG tank and LNG vaporizers to enable supplies to the 35-megawatts power plant. "We will leverage our value chain know-how to expand our energy business in Asia," explained Osaka Gas. "The company will continue working toward winning orders for LNG terminal construction and consulting services outside our territory and overseas, by effectively applying the know-how acquired through our extensive experience," it said. The utility and energy company aims to contribute to group profit growth by steady execution and expansion of East Texas shale-gas project through the Sabine Oil & Gas Corp. The company said it was additionally pleased to be the recipient of volumes from the Freeport LNG export plant on Quintana Island in Texas. US power ventures are being targeting and it has a joint venture with General Electric in the 1,050 MW Fairview Energy Center project in Jackson Township in Pennsylvania.

Osaka Gas is also an LNG volume holder from projects in the Asia-Pacific region as well as the US. Its contracts are with plants such as the Chevron Corp.-operated Gorgon plant on Barrow Island in Western Australia and the Ichthys LNG plant in Australia's Northern Territory, operated by Japanese energy company Inpex Corp. The Japanese utility has other long-standing LNG contracts with Qatar, Indonesia, Malaysia, Brunei, Papua New Guinea and Russia. In Japan, Osaka Gas is involved in value chain operations in the Greater Tokyo area, including natural gas supply in Ogishima and thermal power generation in Fukushima. The Fukushima gas power plant of 1,180 MW is scheduled to start up in several week in April, 2020. The company said it was also working on upgrading and replacing ageing pipelines among its more than 20 high-pressure trunk lines and in Japan. "We aim to enhance the resilience of gas distribution facilities for gas supply security and stability, speedy recovery from disasters, and efficient business operations," said the company. "We will solve ageing pipeline issues for the execution of the advanced gas safety plan and will enhance capabilities of early recovery from disasters such as earthquakes, typhoons and heavy rains," it added.

PEMBINA Pipeline Corp. of Canada said US regulators had approved its Jordan Cove LNG liquefaction and export plant at Coos Bay in the northwest state of Oregon as well its Pacific Connector Gas Pipeline project. "Jordan Cove is the first ever US West Coast natural gas export facility to be approved by US Federal Energy Regulatory Commission," said Pembina. "This federal approval is a significant milestone for the project and for Pembina," added the Calgary, Alberta-based company. Pembina acquired Jordan Cove in late 2017 in its takeover of another Canadian company, Veresen Inc., and has since been working towards obtaining extensive local, state and federal regulatory approvals. The project includes a 230-mile pipeline which would traverse four counties in Southern Oregon on the route to the liquefaction plant.

The liquefaction plant and other facilities are planned for a 200-acre site and comprise five small-scale Trains each with 1.5 million tonnes per annum of output for a total of 7.8 MTPA. The Jordan Cove venture's other facilities would include two full-containment LNG storage tanks with total capacity of 320,000 cubic metres, gas treating facilities, an export jetty and access to more than 25 billion cubic feet per day of gas supply from Western Canada and the US Rockies. The US Coast Guard had already issued a Letter of Recommendation indicating that the Coos Bay Federal Navigation Channel would be considered suitable for the LNG marine traffic associated with the project. The plant would be visited by about 120 LNG carriers per year and Pembina has confirmed that it had signed preliminary accords with Jera Co. Inc. and Itochu Corp. of Japan for the supply of LNG.

The project's affiliated Pacific Connector pipeline will have a 36-inch diameter with capacity to transport up to 1.2 billion cubic feet of natural gas per day. The pipeline will originate at interconnections with existing pipeline systems in Klamath County, Oregon, and would span parts of Klamath, Jackson, Douglas, and Coos Counties before connecting with the export plant. "Natural gas for Jordan Cove would be sourced at the Malin Hub, creating a new outlet for natural gas from areas such as the Rockies Basin," said Pembina. "The project represents a significant opportunity to bring tremendous economic benefits to the State of Oregon and Western Colorado and make a substantial contribution to addressing global climate change by replacing coal in Asia," stated the Canadian company. Pembina noted that the FERC's approval of the project is the result of comprehensive environmental, safety and security reviews involving input from both federal and state agencies, Tribes, landowners and many other stakeholders. "We appreciate FERC's science-based approach to their review," said Harry Andersen, Pembina's Senior Vice President and chief Legal officer. "The approval emphasizes yet again that Jordan Cove is environmentally responsible and is a project that should be permitted given a prudent regulatory and legal process was undertaken," stated Andersen. "The FERC's decision is due in no small part to our many supporters who have turned out time and time again to voice their support for Jordan Cove and to show that the project is in the public interest, including in Southern Oregon and the Rockies Basin," added Anderson. In addition to this federal approval, Pembina said Jordan Cove recently received approval on all 14 local jurisdiction county and city applications and permits. "The company has also signed voluntary easement agreements that constitute 77 percent of the privately-owned portion of the proposed pipeline route, which will allow the pipeline to cross beneath these properties," added Pembina.

PETROCHINA, the Hong Kong-listed arm of state-owned China National Petroleum Corp., recorded a 6 percent increase in annual revenues to 2,520 billion Chinese yuan ($350.8Bln) but net profits fell 14 percent and it disclosed plans to renegotiate some natural gas supply contracts to improve profitability. The company said net profit attributable to shareholders dropped to 45.68Bln yuan ($6.45Bln) compared with 52.59Bln yuan ($7.43Bln) in 2018, while basic earnings per share came to 0.25 yuan ($0.03). "Marketable natural gas output reached 3,910 billion cubic feet, representing an increase of 8.3 percent compared with last year," said the company. "The oil and natural gas equivalent output amounted to 1,561 million barrels, representing an increase of 4.6 percent," it added. PetroChina added in a briefing that it planned to engage in price renegotiations with global natural gas suppliers to control costs and curb losses at its gas import business, without giving other details.

PetroChina imports pipeline natural gas from Central Asian countries and Russia as well as imports from projects such as Yamal LNG and from PetroChina LNG agreements. The Chinese major is additionally part of Royal Dutch Shell's LNG Canada project under its own name PetroChina and has a stake in the Area 4 reserves in the Rovuma Basin offshore Mozambique with Italian company Eni and ExxonMobil of the US that will underpin their Rovuma LNG project. The China-Central Asia natural gas pipeline built by the Chinese company, and which runs through Turkmenistan, Kazakhstan and Uzbekistan to China, has transported around 300 billion cubic metres of natural gas to China since it come on line 10 years ago. PetroChina added that it had not yet reached agreement with China's newly established national pipeline group regarding the transfer of its key pipeline assets. The National Development and Reform Commission in May 2019 released new oil and gas liberalization measures to require facility operators to open up access to their oil and gas infrastructure to free up the flow of natural gas.

The new measures follow the government's announcement earlier in 2019 that it plans to establish a national pipeline company as part of China's move to accelerate the opening up of its markets and to extend the gas network to provide a nationwide alternative to coal. PetroChina added in its earnings report that Natural Gas and Pipeline marketing division optimized domestic and international resources, including LNG imports, and implemented state pricing policy, expanded the development of end-user marketing and raised efficiency. "The company carried out the construction of key projects in an orderly manner, including the completion and operation of the northern section of China–Russia East-Route Natural Gas Pipeline," said PetroChina. "In 2019, sales of natural gas amounted to 259.09 billion cubic metres, up 19.5 percent year-on-year, including domestic sales of natural gas of 171.381 billion cubic metres, and increase of 7.4 percent," it added. The Natural Gas and Pipeline division had operating profits of 26.11Bln yuan ($3.68Bln), an increase of 2.3 percent from 2018. PetroChina's Exploration and Production Division realized an operating profit of 96.09Bln ($13.56Bln) an increase of 30.7 percent. "The oil and gas lifting cost was US$12.11 per barrel, representing a decrease of 1.6 percent year on year," it said in the earnings report. "The E&P division worked on complex geological structures, and discovered the Qingcheng oilfield in Changqing, and two gas fields including the shale gas blocks in Sichuan and Bozi-Dabei gas area in Tarim, which consolidated the company's resources base," said PetroChina.

PetroChina said its Refining and Chemicals increased the production of chemicals and propelled the transition and upgrade of the business assets. The company said its refineries processed 1,228 million barrels of crude oil during 2019. In its outlook for the rest of 2020, PetroChina expected geopolitical tensions, uncertainties about the global oil price, climate change issues and the coronavirus pandemic mean more "downward risks' for the global economy. "Yet, China's economic momentum will ensure the growth trend remains stable and favorable in the mid to long term," stated the company. "PetroChina will adhere to executing the strategies of resource, marketing, internationalization and innovation, while focusing on efficiency and fostering high-quality developments," said the company. "It intends to deepen reform and innovation, attaching great importance to research and development of new energy and renewable energy to fuel growth," stated PetroChina. "These measures will help the company transform its status as a top-class international energy company and taking it to a new level," it concluded.

PETROFAC, the London-based oil and gas services company, said it received a notice of termination from LNG exporter Abu Dhabi National Oil Company (ADNOC) in the United Arab Emirates for two natural gas contracts worth $1.65 million. ADNOC only awarded the contracts to Petrofac in February 2020 for the Dalma Gas Development project. The Dalma project is a key part of the Ghasha ultra-sour gas concession which is central to ADNOC's strategic objective of enabling gas self-sufficiency for the UAE. The UAE is the oldest LNG producer in the Middle East from its Das Island plant offshore Abu Dhabi consisting of three Trains with nominal capacity of 5.5 million tonnes of LNG per annum.

"Petrofac is committed to working with ADNOC over the coming weeks to explore alternative options to deliver this project in a way that supports their strategic objectives within the current challenging environment," said a Petrofac statement. "Petrofac continues to progress execution of its remaining Group backlog of around US$7Bln as planned and is still progressing with tendering for major contracts in Abu Dhabi," added Petrofac. "However, it anticipates this development may have an impact on the timing of their awards," it added. The work scope of Dalma Gas Development encompassed offshore packages at Arzanah Island and surrounding offshore fields, located around 140 kilometres off the north-west coast of the Emirate of Abu Dhabi. The first package, valued at $1.065Bln was for gas processing facilities at Arzanah Island.

Under the terms of the 33-month lump-sum contract awarded to Petrofac, the scope of work included inlet facilities with gas processing and compression units, power generation units, utilities and other associated infrastructure. For the second package, valued at $591 million, Petrofac headed a joint venture with SapuraKencana HL of Malaysia. Under the terms of the 30-month lump-sum contract, the scope of work included three new well-head platforms, removal and replacement of an existing topside, new pipelines, subsea umbilicals, composite and fibre optic cables. Petrofac was established in the UAE in 1991 and has operational centres in Abu Dhabi and Sharjah. It has previously executed 11 major EPC projects in-country to date. Recent projects include the Upper Zakum UZ750 project, Qusahwira Field Development Phase II, the Satah Al Razboot (SARB) Package 3, the contract for expansion of compression facilities at the Bab field and development of the Bab Habshan-1 project.

PREEM, the Swedish refining company and fuel exporter, signed an agreement with Gasum of Finland to purchase a new liquefied natural gas blend containing 10 percent biogas to fuel two LNG-powered oil-chemical tankers. Gasum is the largest LNG distributor in the Nordic region for LNG and biogas truck fuel and a leading LNG bunkering

Diary of events

July
FLAME natural gas and LNG conference
6 - 7 July 2020
Hotel Okura, Ferdinand Bolstraat 333, Amsterdam, The Netherlands
https://informaconnect.com/flame-conference/

September
Gastech Exhibition & Conference 2020
8 -10 September 2020
Singapore EXPO, 1 Expo Drive, Singapore
https://www.gastechevent.com/

December
23rd World Petroleum Congress
6 - 10 December 2020
George R. Brown Convention Center
1001 Avenida De Las Americas, Houston, Texas, USA
https://www.wpc2020.com/

provider for Baltic and North Sea shipping. Preem has two refineries and supplies gasoline, diesel, heating oil and renewable fuels to companies and consumers in Sweden, though exports two-thirds of its production. State-owned Gasum said its deal with Preem is the first involving a blend biogas made from waste, and which some refer to as renewable fuel, to a maritime customer on a regular basis.

Preem's vessels to be supplied with Gasum's blend of blended LNG maritime fuel are the LNG-powered and time-chartered tankers "Tern Ocean" and "Thun Evolve". The "Tern Ocean" is 14,827 deadweight tons and carries oil and chemicals and is Danish-flagged. The second vessel, the Dutch-flagged "Thun Evolve", is also an oil-chemical tanker but is smaller at 7,999 Dwt. "Maritime transport is an important part of Preem's operations," said Anna Karin Klinthäll, Manager of Trading Operations at Preem. "We are very pleased to be able to introduce renewable liquefied biogas into our fuel mix," she added. "This opportunity supports our high-end sustainability requirements," stated Klinthäll.

Using LNG as maritime fuel reduces emissions of greenhouse gas (GHG) by up to 20 percent when compared to conventional fuel.

LNG is the most environmentally friendly fossil shipping fuel, meeting both current and long-term environmental requirements set by the International Maritime Organization. "Gasum is committed to working for a carbon-neutral future and helping our customers to reduce their own carbon footprint by providing cleaner energy," said Jacob Granqvist, a Maritime business executive for Gasum. "We are happy to support Preem towards greener shipping and particularly their vision of leading the transition towards a sustainable society," added Granqvist. Preem supplies more than half of Sweden's industrial companies and one third of the small companies with heating and energy products. It also has a nationwide service network with some 570 fuel stations for cars and commercial vehicles. Preem's two refineries employ 950 workers at Gothenburg and Lysekil.

QATAR Petroleum said it had started a development drilling campaign for the North Field project that will underpin the feed-gas needs for the LNG expansion at Ras Laffan from 77 million tonnes per annum to 110 MTPA. Qatar Petroleum had earlier awarded a number of contracts for jack-up drilling rigs to be utilized for the drilling of 80 development wells. The installation of the first four Offshore Jackets in Qatari waters is underway and was expected to be completed by the end of April. The first development wells were spudded on 29th March by the jack-up rig "GulfDrill Lovanda", which is managed and operated by GulfDrill, a joint venture between the Qatar-based drilling champion, Gulf Drilling International, and Seadrill Limited.

A second phase of the North Field LNG expansion, called the North Field South Project (NFS), will further increase Qatar's LNG production capacity from 110 MTPA to 126 MTPA. "The start of the development drilling campaign represents an important milestone to deliver on our strategy to grow our LNG production capacity," said Qatar's Minister of State for Energy Affairs and President and Chief Executive of Qatar Petroleum, Saad Sherida Al-Kaabi. "The continued achievement of milestones, dedication of significant resources and making of substantial investments demonstrates our commitment to executing this mega-project," added Al-Kaabi.

"I would like to thank Qatar Petroleum and Qatargas management and teams for this important achievement and for making sure that every component of the project is delivered safely," he stated. The scope of the first phase of the expansion at the Ras Laffan production complex involves an additional four Trains, each with 8.0 MTPA of output. Qatar has also short-listed several international energy majors for stakes in its expanded North Field projects. Qatar has the southern portion of the North Field in Gulf waters and the other part is under the jurisdiction of neighbouring Iran.

RUSSIAN authorities have brought in tax breaks for Arctic region liquefied natural gas and oil projects proposed for Northern Siberia where increased output will help take the Russian LNG export total to 75 million tonnes per annum. The tax relief will primarily benefit independent natural gas producer Novatek, operator of the three-Train Yamal LNG plant at Sabetta, with nameplate capacity of 16.5 MTPA, and developer of the Arctic LNG II project on the Gydan Peninsula, which will have 20 MTPA of output. The new Russian law also includes taxation support for the Vankor oil and gas fields being developed by state-backed oil company Rosneft. Under the new law, taxes on all new Arctic Shelf oil recovery projects will be reduced to 5 percent for the next 15 years and the tax percentage falls to 1 percent or lower for all new natural gas projects.

The law also stipulates that oil drilling in the eastern Arctic will be even more advantageous for investors and will incur a zero-level production tax. Onshore natural gas developers in northern Siberia, such as Novatek's, will also have a zero-percent mineral extraction tax for the next 12 years. The cost of the Arctic LNG II project, matching Novatek's Yamal plant, is estimated at more than $20 billion and the venture includes Russian, French, Japanese and Chinese investors. A final investment decision on Arctic LNG II was taken in September 2019. The joint venture participants in addition to Novatek include French energy major Total, a shareholder in Novatek.

The Asian investors are two Chinese majors, China's National Petroleum Corp. and China National Offshore Oil Corp., Japanese state body, Japan Oil, Gas and Metals National Corp. (Jogmec) and Japanese trading house Mitsui & Co. Novatek's Arctic joint venture proposes constructing three liquefaction Trains, each with output of 6.6 million tonnes per annum using gravity-based structure platforms made of concrete and attached to the sea floor. The shareholdings of the various participants are: Novatek 60 percent and the four other partners, Total, CNPC, CNOOC and the Mitsui-Jogmec each with 10 percent. Total and CNPC are shareholders in the existing Yamal plant. Total additionally owns a 19.4 percent stake in the Novatek company so its 10 percent direct stake in Novatek's second plant gives it 21.6 percent of the Arctic project. The business of building ports and other infrastructure to support LNG and oil projects in the region will also be made more economic with companies given a break from any income tax for 10 years.

SANTOS, based in Adelaide, said it signed an accord to sell a 12.5 percent interest in the Barossa natural gas project planned as a feed-gas source for Darwin LNG to the largest Japanese LNG importer, JERA Co. Inc. JERA already has a 6.1 percent interest in Darwin LNG, which Santos bought control of when it took overt the Northern Australian assets of US major ConocoPhillips. "The letter of Intent with JERA advances partner alignment between the Darwin LNG and Barossa joint ventures for the development of Barossa as backfill for Darwin LNG," said a statement.

JERA formally took over the existing thermal power generation businesses from Chubu and Tokyo Electric Power in April 2019. In addition to running the joint Tepco-Chubu power plant assets, Jera is also responsible for fuel procurement. The company now has contract volumes of LNG amounting to 35 million tonnes per annum, upstream investments in five projects and is increasing its LNG fleet from 18 vessels to 25 to ship its cargoes.

For its power generation units of Chubu and TEPCO, JERA controls domestic power capacity of around 70 gigawatts. Santos Chief Executive Kevin Gallagher said signing the accord with JERA follows the recent agreement to by Santos sell a 25 percent interest in Darwin LNG to South Korean utility and energy company, SK E&S. "Following completion of the ConocoPhillips acquisition and the sell-downs to JERA and SK E&S, Santos will hold a 43.4 percent interest in Darwin LNG and a 50 percent interest in Barossa," Gallagher explained.

"We are continuing to advance discussions with other parties for the sale of further equity in the Barossa project in line with our previously stated target ownership level of around 40 percent," stated the Santos CEO. Gallagher, whose company operates the Gladstone LNG export plant in Queensland and has a stake in Papua New Guinea LNG, said he was in discussions with buyers for Barossa volumes. "However as we announced on 23 March, given the uncertain economic impact of Covid-19 combined with lower oil prices, we expect to defer FID on Barossa until business conditions improve," explained the CEO. "Barossa remains an important project for Santos due to its brownfield nature and low cost of supply, and we will continue to use this time to further strengthen the economics of the project," stated Gallagher. Santos made the acquisition deal with ConocoPhillips for its Australian assets in northern Australia in 14 October 2019. These included its interests in Darwin LNG and the Bayu-Undan and Barossa gas fields.

SHELL has pulled out of the Lake Charles LNG export venture in Louisiana being developed with US pipeline and midstream partner Energy Transfer, citing difficult market conditions. Shell said it would continue to support Energy Transfer with the ongoing bidding process for the engineering, procurement and construction contract and then planned to make a phased handover of the project's remaining activities. The Lake Charles liquefaction and export project was being developed on a 50-50 basis and was aimed at transforming the existing import facility at Lake Charles by adding liquefaction capacity of 16.45 million tonnes per annum. The Lake Charles facility was the longest-serving US import terminal before the shale-gas boom and previously imported cargoes from nations such as Trinidad & Tobago and Equatorial Guinea.

Under the transformation proposal, Lake Charles will become an export facility and is in the midst of choosing an EPC contractor after the second quarter of 2020 and a final investment decision was scheduled by year-end. "This decision is consistent with the initiatives we announced last week to preserve cash and reinforce the resilience of our business," said Maarten Wetselaar, Director, Integrated Gas and New Energies at Shell in a statement of explanation. "Whilst we continue to believe in the long-term viability and advantages of the project, the time is not right for Shell to invest," added Wetselaar. "Through the transition, we will work closely with Energy Transfer," he stated.

Energy Transfer said in a statement that it was pressing ahead with the venture on its own for now. "Energy Transfer will evaluate various alternatives to advance the project, including the possibility of bringing in one or more equity partners," said the Dallas, Texas-based company. It would also consider a possible reduction in the Lake Charles output capacity from three Trains to two Trains with a total of 11.0 MTPA of output. Shell's only other sizeable US LNG presence is as the main customer for cargoes from the Elba Island export facility near Savannah in the state of Georgia. Elba Island come on stream and produced its first cargo in late 2019. The Anglo-Dutch company's main North American sector investment is now the LNG Canada project in British Columbia. Energy Transfer and Shell had signed a framework agreement designating Shell as the project leader and as construction manager and operator of Lake Charles LNG.

Under the Shell exit accord, the project leader role has been formally handed to Energy Transfer. The Federal Energy Regulatory Commission has authorized a deadline for the Lake Charles plant to be completed by mid-December 2025. Shell gained its stake in Lake Charles from its takeover in 2015 of BG Group of the UK. Energy Transfer began in 1995 as a small intra-state natural gas pipeline operator and is now one of the largest energy infrastructure firms in the US. Lake Charles would have be Shell's largest North American liquefaction export foothold, rivalling its LNG Canada joint venture. LNG Canada is currently under construction at Kitimat on the Pacific Coast of BC. However, the Canadian project on March 17 said it was cutting back the workforce onsite because of the coronavirus.

SHELL and the privately-owned Chinese company, GCL Oil & Natural Gas Co., have signed an agreement to explore the establishment of a joint venture based in eastern China to market and trade liquefied natural gas. GCL, whose parent company, the GCL Group was previously involved in the development of a pipeline in Ethiopia, said the proposed venture would secure LNG supplies from Shell and market the fuel to a receiving terminal GCL is planning in eastern Jiangsu province. A Shell statement confirmed the existence of the agreement. GCL is one of several Chinese natural gas and LNG developers outside state-backed majors. Other independents include ENN Group and China Gas Holdings Ltd.

The Chinese majors, China National Offshore Oil Corp., China National Petroleum Corp. (PetroChina) and China Petroleum & Chemical Corp. (Sinopec) own most of the network of 20 LNG terminals in China. ENN Group is currently the only exception in owning and operating the Zhoushan LNG import terminal in Zhejiang province, south of Shanghai. GCL said it was planning three onshore receiving terminals along China's East Coast at Yantai in Shandong province, at Rudong in Jiangsu and at Maoming in southern Guangdong province. The three terminals would have total initial capacity of just under 15 million tonnes per annum with scope for expansion. Among them, the 5 MTPA Yantai project was the first of the three to have won state regulatory approval in October 2019. The Yantai terminal would be built at an estimated cost of $1.1 billion and with start-up scheduled for 2023.

SHELL has been given more time by the Australian regulatory authorities to meet additional safety requirements on its Prelude floating LNG export hull deployed offshore northwest Australia. Shell was told that due to "mitigating circumstances" of the coronavirus, it had been given until May 31 to satisfy the list of requirements that followed a previous inspection visit. The Australian regulator that has issued new directives to Shell is the National Offshore Petroleum Safety and Environmental Management Authority (Nopsema). The Prelude FLNG hull, located 475 kilometres north-northeast of the town of Broome in Western Australia, started commercial operations in June 2019 and has capacity to produce 3.6 million tonnes per annum of LNG. It is anchored in the Browse Basin and is the world's fourth FLNG venture to start operations.

According to Nopsema, Shell had made significant progress during the previous audit to ultimately comply with the regulations. At the end of January 2020, Shell was asked to act on two particular issues on the Prelude hull. It was firstly told, to conduct a detailed review of those aspects of the safety management system (SMS) that related to the safe isolation of plant and equipment and to identify the gaps with industry good practice. Another directive told Shell "not to conduct intrusive activities into plant and equipment where the loss of containment as a result of that intrusive activity could result in risk to the health and safety of persons." Nopsema had conducted an inspection that included the topic "Safe Isolation of Plant and Equipment". It said at the time that Shell's written aspects of the SMS were broadly consistent with good industry practice. However, the report made 10 recommendations to improve minor gaps. "Since September 2019 there have been three notifications of dangerous occurrences at the Prelude FLNG Facility that Nopsema inspectors attributed to deficiencies in the aspects of the SMS that relate to the safe isolation of plant and equipment," it added.

There are currently four FLNG production vessels in commercial operation worldwide. The first FLNG hull to enter production was one developed by Petronas of Malaysia and which has already been moved to a new stranded gas field location. A second hull is in production offshore Cameroon in West Africa in a venture run by European energy company Perenco and partners and a third is the "Tango FLNG" barge at the port of Bahia Blanca in Argentina. The Prelude production hull is the first deployment of Shell's own FLNG technology and comprises a 488-metre long facility. For the Shell project, the Concerto gas field and the nearby Prelude field, with combined resources of around 3 trillion cubic feet, are being used to produce the LNG. The Prelude joint venture is owned 67.5 percent by Shell and 17.5 percent by Inpex Corp. of Japan, operator of the Australian Ichthys project and a partner of Shell in the Abadi joint venture to be constructed on a small island in Indonesia. A further 10 percent of Prelude is held by LNG buyer Korea Gas Corp. and 5 percent by CPC Corp. of Taiwan.

SUBSEA 7 SA has been awarded a contract by Chevron Corp. on the $5.7-billion first phase of the Anchor field project in the Gulf of Mexico. Phase one of the Anchor development consists of a seven-well subsea development and semi-submersible floating production unit. First oil and gas are anticipated in 2024. The planned facility has a design capacity of 75,000 barrels of crude oil and 28 million cubic feet of natural gas per day. Subsea 7 said its contract was for subsea installation services at the field, located in the Green Canyon area of the Gulf and about 140 miles (225km) off the coast of Louisiana in water depths of up to 5,000 feet (1,524 metres). Luxembourg-headquartered Subsea 7 said the scope of its work included project management, engineering, procurement, construction and installation of components including the production flowlines, risers, umbilicals and other equipment.

The company said project management and engineering would commence immediately at Subsea 7's offices in Houston. Fabrication of the flowlines and risers will take place at Subsea 7's spool-base at Ingleside in Texas, with offshore operations anticipated to occur in 2022 and 2023. Craig Broussard, Vice President for Subsea 7 US, said his company was honored to be selected by Chevron for the Subsea, Umbilicals, Risers and Flowline (SURF) systems installation on the Anchor project. "We look forward to building on the collaborative relationship with Chevron to deliver a best-in-class project," added Broussard. "The combination of the SURF scope for Subsea 7 and the ongoing subsea equipment delivery by OneSubsea, will allow the Subsea Integration Alliance to work in partnership with Chevron to unlock the value of an integrated approach," he stated. According to Chevron, the total potentially recoverable oil-equivalent resources for Anchor are estimated to exceed 440 million barrels. Chevron holds a 62.86 percent working interest in the Anchor project and co-owner, French major Total, holds a 37.14 percent working interest.

TOTAL said it signed a pioneering agreement to charter its first two Very Large Crude Carrier-type oil tankers equipped with liquefied natural gas propulsion. These two ships, each with a capacity for 300,000 tonnes of crude, will be delivered in 2022 and will join the French major's charter fleet. The crude carriers are being chartered from the Malaysian shipowner AET, a subsidiary of the shipping line and LNG carrier owner, MISC Group. The vessels have been designed with LNG propulsion to reduce their greenhouse-gas emissions, and with the most recent technological innovations to minimize their own fuel consumption. "LNG is the best solution immediately available to reduce the footprint of maritime transport on its environment," said Luc Gillet, Senior Vice President for Shipping at Total. "The use of LNG as a marine fuel for our chartered vessels is an illustration of our determination to reduce the carbon footprint of our operations," added Gillet.

Used as a marine fuel, LNG sharply reduces emissions from ships, resulting in a significant improvement in air quality, particularly for communities in coastal areas and port cities. International Maritime Organization regulations came into force in 2020 to cut the sulfur content in fuel to 0.5 percent or lower as part of an overall move for cleaner fuel for ships. LNG will be supplied to these two LNG-powered VLCCs by Total Marine Fuels Global Solutions, Total's subsidiary dedicated to bunkering activities worldwide. Total is also cooperating with Japanese shipping company Mitsui Osk Lines in assembling small-scale LNG bunkering ships. The company signed a long-term charter contract for a second LNG bunkering vessel to be delivered from China in 2021 and deployed in the Mediterranean. Total has said the new bunkering ship would conduct its operations in the South of France, around the Marseille-Fos LNG delivery and port area.

This bunker vessel is being built by Hudong-Zhonghua Shipbuilding in Shanghai, China. The newbuild will be operated under the French flag by MOL, jointly with Gazocean, the French company based in Marseille and one of the most experienced in LNG carrier transportation. The first Total-MOL LNG bunkering vessel was launched in Shanghai in November 2019 and is operating from Rotterdam in the Netherlands and other Northern European ports. It is a key supplier of LNG fuel to commercial vessels, including 300,000 tonnes per annum to the French container line CMA CGM and its nine ultra-large newbuild containerships which will be sailing on the Europe-Asia trade route.

WOOD MACKENZIE, the UK-based energy consultants, said the while the collapse of LNG prices towards US production break-evens was foreseeable, the narrative for the rest of 2020 could not be more unpredictable. In their latest short-term natural gas and LNG outlook, the consultants weigh the risks that coronavirus, sustained low oil prices and LNG oversupply pose to the sector this year. "An already oversupplied LNG market comes out of a mild winter with high inventories across Europe and Asia, only to face a global pandemic which has already destroyed gas demand across China and looks increasingly set to do the same across the Asia Pacific and Europe," explained Wood Mackenzie research director Robert Sims. "We expect global LNG demand to grow by 6 percent year-on-year to 371 million tonnes in 2020; the numbers will need constant revision as economies around the world feel the force of the growing pandemic," said the report. Wood Mackenzie said the impact to gas consumption in China had been severe, as robust containment measures were quickly put in place through January and February 2020. With a resumption in economic activity, the report estimates a full-year gas demand reduction of between 6 billion cubic metres and 14 Bcm in 2020, translating to a 4 percent to 6 percent growth in gas demand this year. "With the daily number of new cases continuing to fall in China, policy focus has turned to gearing up economic recovery," said Wood Mackenzie. "Daily tariff indicators suggest transport and logistic constraints are being lifted quickly," it added. "Also, the government is reducing gas prices to non-residential users, which provides support to coronavirus-affected businesses to resume operations," stated the report.

However, in Wood Mackenzie's view these measures were insufficient to stir lost-demand recovery and new coal-to-gas switching programmes. China's LNG demand is expected to reach 65MT this year, representing a 6.6 percent growth year-on-year. The report noted that in Europe, low gas prices continue to support gas-fired generation, though future coronavirus containment measures and threats of an economic downturn pose a risk to market growth. "Worst-case scenarios could see lockdowns deployed in more countries, risking severe disruptions to global supply chains by restricting movements of people and goods," said Wood Mackenzie. One outcome of the oil slump appears to be that sustained low prices supports coal-to-gas switching in the power sector but hurt US producers

Wood Mackenzie forecasts that should low oil prices be sustained, oil-indexed LNG contracts in Japan and South Korea will become cheaper and this could disrupt coal generation in favour of gas in both markets. This could happen as early as August 2020 and the effects would be similar to sustained low Dutch Title Transfer Facility prices in 2019 removed coal from power grids across Northwest Europe. The consultants expect Japan's LNG demand to grow 5.1 percent to 81MT in 2020, compared to last year. At the same time, the forecast South Korea's LNG demand could rise 7.7 percent to 42MT as more LNG displaces coal in the power sector of both countries.

WOODSIDE Petroleum, the operator of two LNG export plants in Western Australia, posted a 12 percent first-quarter increase in oil and gas production, though prices were down 20 percent along with revenues from the same three months a year ago. Woodside, one of the biggest regional suppliers of LNG cargoes to North Asia, reported sales revenue of US$1.08 billion for the quarter ended March 31, down from US$1.36Bln a year earlier. Production came to 24.2 million barrels of oil equivalent, up from 2.17M boe as the company mitigated the impacts of Tropical Cyclone Damien during the quarter. Total LNG output for Woodside rose 4.5 percent to 18.31M boe from 17.53 boe in the prior-year quarter. At the same time, Woodside like all other companies in the industry implemented responses to the combined effects of the Covid-19 outbreak and lower commodity prices.

Woodside's first-quarter one-sixth share of LNG sales at the North West Shelf plant in Western Australia came to 606,577 tonnes, down from 652,246 tonnes in the same quarter of 2019. The Perth-based company's sales from its stake in the Chevron-operated the Wheatstone plant in the Pilbara region of Western Australia rose to 236,185 tonnes from 175,932 tonnes in the 2019 quarter. At Woodside's single-Train Pluto LNG plant sales amounted to 1.163 million tonnes in the quarter, up on last year's 1.107MT. "Tropical Cyclone Damien, which crossed the Western Australian coast in February, was the most significant weather event ever to pass over Woodside's production facilities on the Burrup Peninsula," stated Woodside Chief Executive Peter Coleman in the company's first-quarter report. "Despite the severity of the storm, the team put in an outstanding effort to ensure the safety of our people and our assets and restore normal operations in a matter of days," added the CEO. "Nevertheless, revenue for the quarter was impacted by reduced trading activity and lower realised prices due to Covid-19 and an unprecedented combination of oversupply and short-term demand destruction," stated Coleman. "Of course, most of the quarter was overshadowed by the growing threat of the Covid-19 pandemic, which has required us to take swift and decisive action to protect our workforce, communities and operations," he said.

Coleman noted that the company had already made "tough but prudent decisions" to ensure the financial integrity of the business with spending cuts in 2020 of 50 percent. "A targeted final investment decision on our Scarborough and Pluto Train 2 developments has been deferred from this year to next," said Coleman. "We made solid progress on our near-term growth projects during the quarter, taking FID on Sangomar Field Development Phase 1 in Senegal and the North West Shelf's Greater Western Flank Phase 3, as well as making significant execution progress on Pyxis Hub and Julimar-Brunello Phase 2," he added. ■

Coronavirus issues and how they affect sales and purchase agreements for LNG supplies

London law firm Squire Patton Boggs gives legal opinion on 'force majeure' and other issues

The Covid-19 outbreak has added another layer of disruption to an already depressed LNG market in Southeast Asia.

It comes in the wake of market players addressing drops in demand growth caused by an unseasonably warm winter period and record low JKM spot market prices - falling to as low as US$2.713 per million British thermal units.

Troubles

While LNG markets have historically taken seasonal demand in their stride, the recent warmer weather has come at a time of rapidly rising supply (in particular, from the US market, which continues to grow its exports).

These factors have all contributed to a growing disruption in the LNG market in Southeast Asia.

On top of historically low prices in the spot markets, there will now be a downwards price trend under long-term SPAs indexed to oil.

Even with the recent fall in oil prices to around US$30 per barrel and lower, it will only be if oil prices are sustained over a longer period that long-term buyers will reap the benefits, plus there will be a time lag in the short-term, whilst prices adjust.

Faced with these concerns, the advent of the virus has inevitably (and understandably) led market participants to consider what contractual options they have to alleviate the difficulties facing them.

The rapid spread of the virus and resulting government lockdowns have prompted various players to actively consider exercising *force majeure* over scheduled cargoes. In some cases, buyers (including CNOOC and PetroChina in the Chinese market) have gone ahead and declared *force majeure*. However, such measures should be carefully considered.

English law

Questions of *force majeure* are rarely straightforward, as the present pandemic illustrates. *Force majeure* has no inherent meaning under English law, but is rather a label given to a common type of contractual term allowing parties to suspend or delay performance of a contract where that performance is affected by a particular event beyond their control.

An extenuating event, an inability to perform the contract and a causal link between the two must usually all exist for *force majeure* to apply.

With respect to trigger events, clauses will often contain a non-exhaustive list of types of disruptive situation that a party may rely on.

Price dislocation or a fall in demand are in themselves rarely valid triggers (for good reason, given the careful allocation of price and volume risk that underpins long-term LNG supply contracts) consequences will generally need to be beyond the party's control.

Provisions

It follows that the party seeking to rely on the provision will often need to show that they have taken steps to mitigate or overcome the effects of the event.

In each case, the application of *force majeure* will depend on the specific wording of the contract.

With regard to the present Covid-19 outbreak, some SPAs may include accommodating wording (e.g. "epidemic" or "pandemic") within the list of specified events.

It is possible to imagine a tribunal or court agreeing with a party seeking to rely on *force majeure* in this context, and parties may soon put this to the test.

At the same time - and subject to the wording of the particular contract - parties are likely to be expected to explain how the event has disrupted their ability to perform their obligations, and what steps they have taken to mitigate or avoid that disruption.

Entitlement

Invoking *force majeure* does not generally entitle a party to "fold their arms and do nothing"1, so if the outbreak has merely made the contract more difficult or expensive to perform, a party may find that *force majeure* cannot come to its aid.

The complex and fact-specific nature of *force majeure* disputes may be part of the reason why regional buyers have historically been unwilling to declare *force majeure* in times of distress, not to mention fears of any possible associated reputational damage.

London law firm Squire Patton Boggs gives legal opinion on 'force majeure' and other issues due to the economic effects of the Covod-19 crisis

It may also explain why sellers immediately appear reluctant to accept such declarations - as was recently witnessed with Total, Shell and Qatargas, who rejected claims of force majeure from their Chinese counterparties.

What, then, should parties to a long-term LNG or natural gas contract do? The answer is to carefully study the contracts in its portfolio. What does the contract contemplate as properly constituting a force majeure event and can it be applied to the present situation?

If so, what other requirements will need to be met to make a valid declaration?

Counterparties

A party may be required to notify the counterparty within a particular timeframe, or have taken specific steps to mitigate the event and its consequences.

In this regard, it is important to consider what other provisions the parties included in the contract to address periods of difficulty.

For example, diversion rights to unaffected terminals or other markets, downward flexibility options and adjustments to cargo delivery schedules (e.g. moving volumes to later in the same or next contract year) are all common contractual mechanisms that a court or tribunal may expect a party to have explored before declaring *force majeure*.

A strong understanding of the contract is a good platform for dialogue between the parties on how to address the present crisis and, thereafter, encroaching into price discussions, if required.

The mechanisms mentioned immediately above are all generally used as sources of flexibility within long-term contracts.

Such flexibility might apply also to other prevailing circumstances in the coming months or years. Covid-19 will undoubtedly curtail short-term regional growth, but a strong economic recovery in large LNG importers, such as China and South Korea, could send spot and short-term prices higher as demand rebounds.

Times of genuine crisis often elicit a desire to put aside differences and work constructively toward a shared outcome.

It may be that parties are able to capitalise on this sentiment, but it is vital they have a solid understanding of what their contracts say before doing so.

If you have any questions regarding the subject matter of this article, please contact one of the authors or your usual firm contact. ■

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Competitiveness of Canada's regulatory framework examined for the LNG and the oil and gas sectors

Canadian Energy Research Institute issues key study covering investment and other issues

Much debate has occurred in Canada about the effectiveness of the various regulatory reviews of energy projects, large and small.

The debate illustrates a tension between those stakeholders wanting a concerted stewardship of our natural environment with those that seek to create private and public benefits from energy project investments.

Improvements

The purpose of this study was to provide facts and evidence impartially so that stakeholders can consider these observations as they move forward with individual oil and gas project reviews and conversations regarding improvements in the process.

This study was conducted to assess the competitiveness of Canada's regulatory frameworks at the federal and provincial levels compared to the United States.

It was also intended to show how regulatory matters compare with other investment factors such as market conditions and project economics.

The Canadian Energy Research Institute (CERI) found that for typical day-to-day approvals of routine small-scale onshore oil and gas wells, Canada and the US have similar requirements and similar processes.

For those projects, there is no significant difference in the competitiveness of Canadian and US project approvals demonstrated in our assessments.

> *Two points raised ... were changes to the Canadian regulatory process and timeline risks and comparisons between the various sectors, including LNG.*

CERI found that Canada has a competitive disadvantage of oil and gas investments compared to the US when it comes to liquified natural gas (LNG) projects and interprovincial oil and natural gas pipelines.

Canada's increased approvals period, on the order of, on average, 13 to 19 months, adds to the cost of projects in Canada.

Moreover, the increased uncertainty of the decision-making process in Canada adds to the cost. Risk-based assessments of cost, if higher, add to the profitability hurdle rate for investors.

In such a situation, when increased costs are combined with risk, competitiveness is challenged. Overall, CERI's analysis found that:

- LNG projects take approximately 19 additional months for approval in Canada than the US providing a competitive advantage to US investments.
- Major oil and natural gas pipeline projects take approximately 13 additional months for approval in Canada than the US providing a competitive advantage to US investments. Pipeline projects that are legally challenged take considerably more time in Canada.
- Canadian timelines are comparable to US timelines for routine projects such as onshore oil and gas well and routine pipeline approvals.

A cost of delay analysis was conducted to identify the economic impact of regulatory delays for each of the six case studies in the report.

Case studies

Those case studies included LNG projects, oil pipelines, natural gas pipelines, oil wells, gas wells and offshore gravity-based structures oil wells.

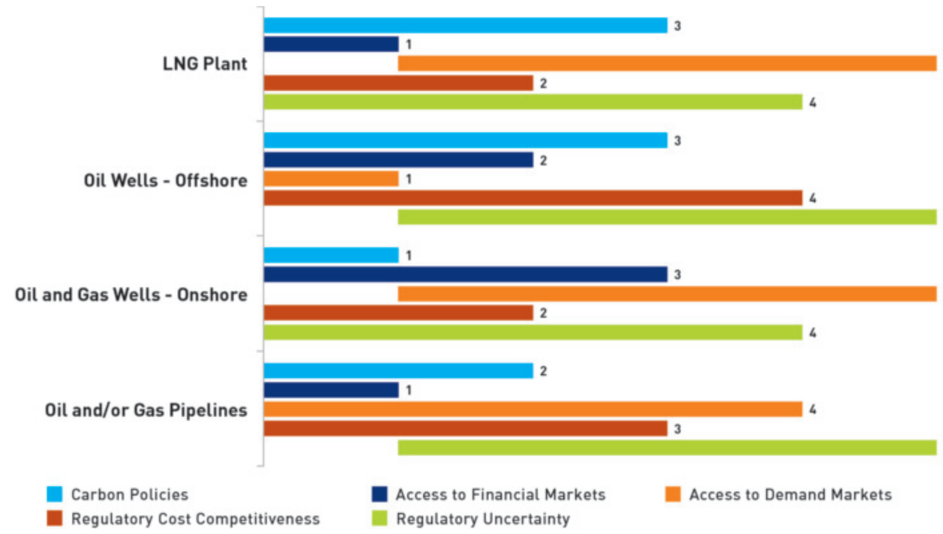


Figure 1: Major factors affecting oil and gas investments in Canada

The cost of delay estimation consists of two main parts:

1) The estimation of capital expenditures (Capex) increases during the delay period, and;
2) Supply cost analysis using discounted cash flow (DCF) models after incorporating the delay period and incorporating new CapEx values.

The cost of a delay to a project can be as high as 15 percent of the overall capital cost in the first year and results in negatively affecting the competitiveness of major Canadian oil and gas projects.

While regulatory certainty and efficiency are investment factors, market supply and demand, as well as project economics, are equally important.

Survey

Figure 1 presents the results of a survey with key stakeholders and illustrates the major factors affecting oil and gas investments in Canada.

These influencing factors are a ranking of risk related to project investment and decision making.

The survey conducted by CERI as part of this study also highlighted the top of mind issues for industry and government to consider. Uncertainty was the most discussed concern.

Two points among many raised in the report were changes to the Canadian regulatory process and timeline risks and comparisons between the various sectors, including LNG.

The new Canadian Impact Assessment Act 2019 was designed to shorten legislated timelines for impact assessment, at the same time increasing public benefits and improving societal outcomes:

- a new mandatory early planning and engagement phase helps to start a dialogue with the public, stakeholders and Indigenous peoples early in the process; that can lead to better project design and better acceptance of the project. If proponents know what is required from them at the project onset, it could make the entire impact assessment more predictable and efficient;
- a shift from environmental assessment to impact assessment based on the principle of sustainability; the project's contributions to sustainability will be evaluated;
- an impact assessment will evaluate not only negative but positive effects of the project as well (i.e., positive changes to the environment, health, social or economic conditions). Examples of positive project effects include local procurement, restoration of degraded landscapes, enhancing employment and training opportunities, etc.;
- a broader range of factors (such as health, social, and economic effects, in addition to the environmental impacts; jobs and the economy over the long-term; gender-based analysis) will be considered;
- recognition of Indigenous rights and interests; mandatory consideration and implementation of Indigenous knowledge;
- an impact assessment will contribute to Canada's ability to meet its

environmental obligations and its commitments in respect of climate change;
- the new efficient and timely decision-making process will contribute to a favourable investment climate in Canada.

As regards LNG, uncertainties in the timelines (along with commodity pricing, market access and labour) are one of the most significant risk factors for investors.

Projects

CERI also conducted a high-level analysis of all major Canadian projects terminated by proponent during the years 2015-2019 for pipelines and LNG projects. The findings are comparable to results in other literature.

Ten Canadian pipeline projects (two terminated) and 8 LNG projects (four terminated) were used for the analysis.

The analyzed sample sizes are not adequate to conclude there is a correlation between project termination and the regulatory process.

According to industry experts, some of the major reasons for project terminations are market-economic factors, regulatory delays, loss of investor confidence and volatile energy policies.

Consideration

The majority of terminated projects have been under regulatory consideration for longer periods than projects that have not been terminated.

It cannot be determined whether these terminations were due to the length of the regulatory process or other factors.

For LNG projects, Canadian approvals take around 95 percent more time (19 months) than US approvals.

Reduction in US regulations in LNG approvals and streamlining attempts for LNG approvals (examples: Driftwood LNG and Pipeline project and the Port Arthur LNG and Pipeline project) may have resulted in the US approval periods being significantly shorter than Canadian approval periods.

Delay issues

Note that in Canada, there have been a significant number of legal challenges for LNG associated pipeline projects resulting in overall application delays.

For example, legal challenges, as well as illegal protests and blockades to Coastal GasLink, delayed the LNG Canada project and the Prince Rupert LNG and pipeline project.

For pipeline projects, Canadian approval time takes around 60 percent (13 months) more time than US regulatory approval times.

The pipeline industry is streamlined in Canada, unlike the LNG industry, and the Canadian regulatory framework can be competitive for smaller routine pipeline expansions.

New major pipeline projects with significant environmental impacts and Indigenous impacts seem to be the most delayed pipeline projects on both sides of the border.

Oil and gas well projects reflect the day-to-day business of the oil and gas industry.

For routine oil and gas well approval projects, the timelines for the US and Canada are comparable.

The major problem in assessing impacts of the regulatory process (particularly an impact assessment process) on the project approval timelines is isolating its influences from the influences of other dominant factors previously listed.

In addition to the regulatory delays-uncertainty, factors that can impact FIDs for major LNG-pipeline projects and contribute to a proponent's decision on a project termination include:
- market access, market conditions and global market commodities prices;
- uncertainty in the economic viability and profitability of the project;
- larger investment portfolio options of major oil and gas companies, and;
- stakeholder opposition, legal challenges and no constructive path forward. ■

This article comprises the Executive Summary and brief extracts from the 144-page Canadian Energy Research Institute's paper: "Competitiveness of Canada's Regulatory Framework for the Oil and Gas Sector". The full report was authored by Anna Vypovska, Eranda Bartholameuz, Mohamed Refaei, Andrei Romaniuk, Oluwatosin Adeyemo and with contributions from Ksenia Privalova.

LNG boil-off and contractual compensation regimes - is past practice still best practice?

Marcus Dodds, Partner at Reed Smith, presents the second part of his paper on a hot issue

Boil-off issues, predominantly in the context of time charterparties for liquefied natural gas carriers, but also in the context of short-term trading arrangements under Master Sale & Purchase Agreements (MSPA), are considered in this paper.

Part 1 was published in the April LNG Journal and here is Part 2:

Over the last decade or so, it has also become standard practice in charterparties for an Owner to provide a distinct warranty to the Charterer for laden and ballast (heel) voyages. Although (as noted previously) the same cannot be said for shipbuilding contracts.

As these typically give a singular warranty for a fully laden condition only, and hence why the ballast warranty offered by an Owner to its Charterer, if not simply the same rate as the laden warranty, is invariably based on experience; which has typically pointed to the rate of boil-off for a ballast voyage being around half (depending upon the quantity of heel) what it is on a laden voyage.

Maximum

By whatever means a boil-off warranty is determined, it will invariably be presented as a maximum daily rate expressed as a percentage of the cargo tanks' volumetric capacity (in cubic metres) or pro rata.

For this reason, the standard practice has always been to apply this rate to the volume of cargo or heel (in liquid phase) as gauged before the voyage, taking into account the period elapsed between this and the gauging at the end of the voyage.

This calculated volume is then compared to the actual volumetric difference of the cargo between the two gaugings to determine if the warranty has been complied with and, if the warranty has been exceeded, quantify the level of compensation that may be payable to the Charterer, if not otherwise excused or excepted under the charterparty.

This is hardly controversial, at least in so far as one is prepared to ignore changes in bulk liquid temperature, which give the Owner a small margin of advantage.

However, at this stage something of a wrong turn is usually taken. For the volumetric difference is (usually) then converted into Btu by application of the compositional results of the cargo analysis at the discharge port, i.e. of the weathered (liquid phase) cargo.

Forcing

There really is no logic to this for a laden voyage. Assuming that there was no forcing of boil-off on passage (by use of vaporisers), a comparison of the compositional results of the cargo analysis taken at the load port and the discharge port should reveal that the difference is confined to reductions in the methane and nitrogen contents.

As such, it would be much more logical to approach the problem on a laden voyage by assuming that all of the nitrogen content will have been lost and valuing all of the remainder on the basis that it is pure methane: that is, attributing to the remainder the volumetric to calorific conversion ratio of pure methane (in liquid phase).

Indeed, from an Owner's perspective, this approach is probably still be preferable even if any nitrogen content were ignored and all of the loss treated as if it were homogenous, pure methane (in liquid phase).

Even though the nitrogen content of the cargo, which typically will be around 0.3 per cent of the cargo composition and will preferentially boil-off in the first few days, may amount to 5 per cent or more of all the natural boil-off gas available on the laden voyage.

However, that approach might be a little more contentious on a ballast (with heel) passage, if it were assumed that all of the (liquid phase) heel (including the heavier alkanes) were in fact consumed prior to loading.

Analysis

The obvious reason being that, in this circumstance, the discharge port analysis (of the now weathered laden cargo) would in fact be a fair(er) representation of the boil-off content.

Of course, there is no reason why a different approach could not be taken for the laden and ballast (in heel) voyages, if there is obvious merit in doing so, such that the methane (and nitrogen) only approach is taken for the laden voyage and the discharge port analysis approach is taken for the ballast (in heel) voyage.

It has also become standard practice in charterparties for an Owner to provide a distinct warranty to the Charterer for laden and ballast (heel) voyages

It is suggested that a no more complicated, but seemingly more faithful approach would be to: a) make the simple assessment of the Btu difference between gaugings (where the Btu content will invariably have been assessed in any event); b) assume that the rate of boil-off is constant (which is the same approach taken to date); and c) assess the volumetric difference between gaugings against the warranted difference.

Excess

Any volumetric excess pro-rated against the difference in Btu, could then be taken as the assessed quantity of loss suffered by the Charterer due to a breach of the boil-off performance warranty, subject to the usual excuses or exceptions in the charterparty.

The appropriate LNG price can then be applied directly to any quantity of excess calculated over the performance review period.

Admittedly, this still does not achieve scientific purity (nor is it being pursued, merely for the sake of it).

For example, the bulk liquid cargo temperature should warm to some extent over the period of the voyage and thus to some extent expand, providing a small margin of respite for the Owner (at least on all laden voyages).

That said, the maintenance of an assumed constant rate of boil-off can be justified as both a convenience and because this properly reflects the fact that the warranty given by the Owner is in reality an average rate across the period of a voyage.

Where the period of a voyage is within an exception, such as due to an off-hire event, the terms of the charterparty will invariably assume the rate of boil-off to be constant (if the actual volumetric loss cannot be assessed by gaugings), which is consistent with the suggested approach.

Where the Charterer requires the Owner to force boil-off on a laden voyage, to provide supplementary fuel (in addition to natural boil-off), the terms of the charterparty will invariably release the Owner from its warranty (it being expressly or impliedly for natural boil-off only).

Where the release is partial, and linked only to the period of forcing, the gaugings before and after this period will (subject to the accuracy of those gaugings) address the volumetric element of the assessment in the usual way.

Compromise

Further, the use of the discharge port analysis in the ordinary way to assess the Btu content during the excused period will be a fair compromise for both parties (bearing in mind that, frankly, no better methodology is apparent).

None of what I have suggested so far

should be controversial from a commercial, technical or practical point of view. The suggested approach would achieve a fairer outcome, consistent with the compensatory approach that a breach of a warranty merits.

Of course, one could go a little further down the path of scientific purity and thus fairness.

To which end, there seems to be no reason why the Owner's boil-off rate warranty could not be expressed in Btu rather than a volume of the cargo.

Particularly given that the origin of that volumetric rate, as provided

by the shipyard, is in fact a thermal calculation (based on heat flow and the latent heat of LNG, albeit the daily rate is usually calculated in MJ rather than Btu units).

The warranted Btu rate of loss, applied across the voyage, could then be compared with the actual Btu loss, to assess the performance of the LNG carrier and the excess, if any.

Idea

In making these suggestions, I am fully aware that the difference achieved by such change in most cases may not be considerable, which no doubt is why the issue has not attracted much attention.

It will, of course, depend on the composition of the LNG in question, with a lean cargo creating a smaller margin than a rich one, in any event.

Very roughly speaking in many cases it would probably make about a time such breaches were both rare and small scale.

Unsurprising given the expected consistency of the performance of the insulation systems.

That was until the already discussed issues with warranting the performance of reliquefaction plant arose.

It also has to be remembered that these opportunities to "tidy-up" methodologies are cumulative in effect and to date have arguably been nibbling away at the margins of error that have been protecting Owners.

Consumption

For example: In terms of the consumption warranties, it was not so long ago that the fuel oil equivalent factor in charter parties was typically fixed for the calorific value of marine gas oil even though most LNG carriers were designed only to use residual fuel (at least for prolonged periods).

This oversight for years gave the Owner a margin (from the difference in calorific values) of about 5 to 8 percent in terms of its consumption warranty.

Although, ironically, IMO 2020 (i.e. the reduction of the sulphur contents in marine fuels being brought about by amendments to Regulation 14 of Annex VI to MARPOL Convention) would likely have reversed that anomaly, as reliance on low sulphur marine gas oil seems likely to be a favoured solution to the new regulations.

In terms of the boil-off warranty, until relatively recently, a Charterer was unlikely to expect a distinct or even realistic warranty for ballast passages, allowing any issues with laden passages to be easily off-set (at least outside of single trip time charterparties).

Further, an Owner often used to enjoy a further margin due to a lack of consistency between reliance on the gross cargo tank capacity and gross cargo capacity (i.e. at filling limits): an oversight that for most LNG carriers allowed a 1.5 percent margin.

Further still, an Owner still, arguably, enjoys some margin between the boil-off warranty received from the shipyard, with its basis

on high sea and air temperatures, and the criterion free warranty it gives to a Charterer.

Tank fill

Although the converse is true where a cargo tank is part filled and the Owner's warranty still applies, or is pro-rated (downward) where the expectation would be for the boil-off to increase.

The present suggestion would be a small step towards re-balancing the compensation regimes, but it is of value against the reducing margins of protection that an Owner enjoys in terms of performance warranties.

Fuel oil equivalent factor: Having raised the topic, this is an apt moment to observe how the methodology has generally improved, at

least by reference to the ShellLNGTime2 approach, which moved away from a fixed conversion rate, to adopt an empiric approach: namely analysis of the calorific value of the fuels to which the boil-off is to be compared.

The ShellLNGTime2 approach compares the calorific values of the actual fuels to an acceptable calorific value for pure methane.

Admittedly this ignores the nitrogen content of the LNG, which typically might be around 0.3 percent on loading (but not re-loading) a cargo and there is no reason why this could not have been taken into account.

As, in most cases, it would not be controversial to suggest that the nitrogen content would preferentially boil off to de minimis levels on any laden voyage of more than a few days.

Further, it would hardly be an administrative burden to exclude such content and, on shorter voyages, the omission can have a significant impact.

Alkanes

More notably, this approach does not take into account that on a heel voyage the boil-off, aside from being unlikely to include any nitrogen, is likely to include heavier alkanes.

At least if one assumes that the volume of heel retained was well judged and thus is fully vaporised (with tanks cold and ready to load) on arrival at the next load port.

Ignoring the lack of nitrogen and including the heavier alkanes would probably create around a 2 percent margin, whether the original LNG was rich or lean, assuming a laden voyage of around three weeks and a boil-off rate of less than 0.1 percent per day.

The use of reliquefaction plant to reduce the quantity of heel needed to arrive cold and ready to load, in favour of using bunkers to prosecute the ballast voyage, would of course reduce the significance of the singular orientation (laden only) of the ShellLNGTime2 approach.

The reason being that the fuel oil equivalent factor would have less application.

Which is why it is all the more surprising that some parties, particularly Owners (even in relation to LNG carriers equipped with PRS), have repeatedly attempted to negotiate amendments to the ShellLNGTime2 approach.

Substitution

These would substitute the fixed calorific value for pure methane in favour of the assessed calorific value of the LNG cargo as loaded or, indeed, as discharged value, regardless of whether or not the nitrogen content is excluded (as suggested) for the latter.

Indeed, to make matters worse for the Owner, the cargo value used will probably be a higher calorific value (as that is usually relevant for an LNG sale and purchase contract), whereas bunkers are invariably assessed by reference to their lower calorific value.

Accordingly, an LNG carrier obtaining the benefit of methane from boil-off on a laden voyage would have its consumption performance assessed on the basis that it had been supplied richer fuel; which cannot be in the Owner's best interests and is not representative of what was in fact available as fuel for the LNG carrier.

If that is not an obviously correct statement then let us assume that 75 cubic metres of boil-off was available as fuel in any given day. In that case, the ShellLNGTime2 approach (which, quite correctly, uses the lower calorific value of methane) would calculate a fuel oil equivalent factor as against a typical residual fuel oil of about 0.525, namely about 39 mt as against the daily consumption warranty.

By contrast, if we follow the alternative approach pursued by some parties (as discussed above). Doing so in the context of an LNG cargo with a higher calorific value of around 54 MJ/kg and a density of 430 kg/m3 (e.g. a typical Atlantic Basin cargo), but whilst using the same residual fuel as before.

The result would be that we would achieve a fuel oil equivalent factor of around 0.580. Meaning that the same 75 cbm of boil-off now counts as 43.5 mt towards the daily consumption warranty.

Those Owners that have pursued such amendment should desist from doing so.

Similarly, those Charterers that have promoted the same amendment should recognise that this is an inequitable arrangement, save perhaps where it is applied only to a ballast (heel) passage.

Compensation for boil-off under MSPA: As a general comment, the compensation regimes in relation to boil-off under most MSPAs suggest a greater interest in pragmatism than compensation.

For demurrage purposes under MSPAs, it is still quite common for a single boil-off rate to be agreed in each confirmation note, thus making no distinction between laden and ballast (heel) performance.

Ballast

Even though the natural boil-off rate in ballast condition would usually be around half that for laden condition: an omission that disadvantages an FOB (Incoterm) seller for demurrage purposes.

It may be that the agreed rate has its origins in the boil-off warranties given under the charterparty of a performing ship, but more likely, it will simply be a generic rate based on the parties' experience with such warranties.

The default in a party's standard form MSPA perhaps not having been revisited since the days when steamships and their correspondingly high boil-off rates still dominated the world's LNG carrier fleet (noting that, in my experience, 0.15 per cent per day is still the most commonly found rate).

It is certainly unusual for individual boil-off rates included in a confirmation note to be ascribed to each nominated ship or to incorporate such rate(s) by reference to the warranties of the performing ship(s) (including any substitute(s)) as given under a charterparty.

It is rarer still for a distinction to be made between the boil-off rate for an LNG carrier awaiting a loading or discharging berth, despite the distinction in reality and in most charterparties.

This last point has the potential for absurdity under some MSPAs, where a deemed rate of boil-off is applied to any delay in berthing at a load port.

Paying

This means that payment from the FOB seller to the buyer, in lieu of excess boil-off, can continue long after any heel remaining on arrival would have boiled-off.

This is the more absurd because the seller invariably would have the time and expense of a subsequent cool-down in any event. Coupled with an outdated laden boil-off rate, this approach can achieve extremely punitive results for the FOB seller.

Given the improvements in propulsion efficiency, the as-designed laden natural (passive) boil-off rate for LNG carriers has been correspondingly reduced from around 0.15 percent per day 20 years ago to 0.09 percent or less per day today to match fuel consumption demand.

When under heel, the boil-off rate will typically be half that as when laden and (as discussed above) it is now not uncommon for an Owner to warrant accordingly under a charterparty even if the builders of LNG carriers still do not offer any such distinction.

As also discussed already, the natural boil-off rate achieved by the cargo containment system may be further reduced by the use of PRS or FRS. Typically, the former can reduce the laden boil-off rate to around 0.04 percent per day.

Waiting

When waiting off a berth, the latter can reduce the rate of boil-off to nothing (by volumetric or calorific reference), bearing in mind that all nitrogen should typically have preferentially boiled-off by then anyway.

As such, depending on the age of the ship that actually performs, there is potentially quite a wide margin of advantage to one party or the other.

For example, on a 16 days passage, the margin might be around 1 percent of the total cargo volume.

In any event, the "excess" is not usually measured but calculated by application of the boil-off rate to the volumetric quantity of the cargo.

Further, whereas the actual boil-off during a period on demurrage at the discharge port will almost certainly only comprise methane (as any quantity of nitrogen should have preferentially boiled off on the laden passage), the "excess" boil-off is almost certainly valued at an agreed or referenced LNG price.

In terms of calorific value, this might yield an advantage of around 12 percent to the seller, depending on the source of the LNG and length of laden voyage: as these factors will vary the proportion of methane to heavier alkanes.

Of course, at the loading port the arrangement is usually more curious, as the buyer is compensated for the "excess" boil-off from a cargo that has not yet been delivered, and where the quantity actually delivered may still be within the contractual tolerances.

This arrangement is still the more curious when taking into account the above point that the "excess" boil-off will be valued as if LNG.

A delay in loading any ship could well be expected to have a knock-on effect on the scheduled discharge, and therefore a rationale can be offered for this compensatory regime (in the event of delay caused by the seller).

It is also far more pragmatic than the buyer having to prove its loss, such as for excess consumption in order to maintain the same scheduled arrival time. However, this cannot be said to have a firm foothold based upon logic.

Conclusions

Under the typical performance regimes for LNG carriers, natural boil-off warranties need to be kept distinct from the performance of any cargo reliquefaction systems.

Even so, the typical regimes for assessing the performance of an LNG carrier against its consumption warranty may be flawed, at least in so far as an Owner is prepared to warrant the same for speeds below that which can be achieved using all available natural (passive) boil-off.

The use of PRS or FRS can protect against the potential for inequity (if the reliquefaction plant is available and performing as warranted), but there seems to be a fundamental issue with assessing consumption that could be addressed with quantitative technology and a better adherence to scientific purity - particularly where the basic technology needed may already be available on many LNG carriers.

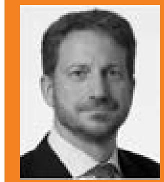
Some of the margins of comfort that Owners have enjoyed in the past with regards to their performance warranties have been slowly eroded, and there are obviously more in-roads that could be made.

The fact that Owners may rarely been exposed to claims in the past is not a reason for them to ignore the issues that exist within some of the performance assessment regimes within charterparties, and even well run ships have problems.

For Charterers, the changes suggested should bring closer alignment to the terms by which the cargoes (usually theirs or an associated party's) are traded and more accurately reflect the value of that cargo and the benefit that its boil-off provides in terms of savings in bunkers.

However, the broader conclusion is that the need for those persons with technical expertise as to the practicalities of carrying LNG cargoes by sea is as important as ever to ensuring that appropriate commercial and legal terms for the same are agreed. ■

Author



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Marcus is an experienced litigator and transactional lawyer. He is capable of handling shipping, trading and Admiralty disputes and also has extensive experience in non-contentious shipping and trading matters, particularly in relation to LNG. He is the leading lawyer in Reed Smith's LNG shipping practice and has been engaged as the legal advisor to SIGTTO for many years. He also sits on Lloyd's Register's Classification Committee, the final arbiter of issues of class, and prior to his legal career was a Captain in the merchant navy having served on a wide variety of ships, including gas carriers. He has over 30 years of experience in the marine industry.

LNG
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CORPORATION

World LNG Carrier Fleet

LNG carrier	Capacity m³	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	GTT	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	GTT	4	Nigeria LNG
Adam LNG	162,000	Oman LNG	Hyundai	Dec-14	Marshall Is.	DFDE	GTT	4	Oman LNG
Adriano Knutsen	180,000	Knutsen	Hyundai	Jul-19	Spain	MEGI-DF	GTT	4	charter
Al Aamriya	210,100	J5 Consortium	Daewoo	Feb-08	Marshall Is.	DRL	GTT	4	Qatargas
Al Areesh	151,700	Teekay LNG	Daewoo	Jan-07	Qatar	S	GTT	4	Ras Gas II
Al Bahiya	210,185	QGTC	Samsung	Oct-09	Liberia	DRL	GTT	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	GTT	4	RasGas II
Al Dafna	266,000	QGTC	Samsung	Oct-09	Marshall Is.	LR DRL	GTT	4	Qatar-Atlantic
Al Deebel	145,000	Peninsular LNG	Samsung	Dec-05	Bahamas	S	GTT	4	Qatargas
Al Gattara	216,200	OSG/Nakilat	Hyundai	Oct-07	Marshall Is.	DRL	GTT	4	Qatargas II
Al Ghariya	210,100	ProNav	Daewoo	Feb-08	Bahamas	DRL	GTT	4	Qatargas
Al Gharaffa	216,200	OSG/Nakilat	Hyundai	Jan-08	Marshall Is.	DRL	GTT	4	Various
Al Ghashamiya	216,000	QGTC	Samsung	Mar-09	Liberia	DRL	GTT	4	Qatar-Atlantic Basin
Al Ghuwairiya	261,700	QGTC	Daewoo	Aug-08	Marshall Is.	DRL	GTT	5	Qatar-Atl'c Basin
Al Hamla	216,000	OSG	Samsung	Feb-08	Marshall Is.	DRL	GTT	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	GTT	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	GTT	4	RasGas
Al Kharaitiyat	216,200	QGTC	Hyundai	May-09	Liberia	DRL	GTT	4	Qatargas III
Al Kharaana	210,000	QGTC	Daewoo	Oct-09	Marshall Is.	DRL	GTT	4	Qatargas IV
Al Kharsaah	217,000	Teekay	Samsung	May-08	Bahamas	DRL	GTT	4	RasGas III
Al Khattiya	210,000	QGTC	DSME	Oct-09	Marshall Is.	DRL	GTT	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	GTT	4	RasGas
Al Mafyar	266,000	OSG/Nakilat	Hyundai	Oct-07	Marshall Is.	DRL	GTT	4	Qatargas II
Al Marrouna	151,700	Teekay	Daewoo	Nov-07	Bahamas	S	GTT		Ras Gas I
Al Mayeda	266,000	QGTC	Samsung	Jan-09	Liberia	DRL	GTT	5	Qatar-US/Var.
Al Nuaman	210,000	QGTC	DSME	Dec-09	Marshall Is.	DRL	GTT	4	Qatargas IV
Al Oraiq	210,000	J5 Consortium	Daewoo	Apr-08	Marshall Is.	DRL	GTT	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	GTT	4	Qatar-Atlantic
Al Ruwais	210,100	ProNav	Daewoo	Nov-07	Germany	DRL	GTT	4	Qatargas II
Al Sadd	210,100	QGTC	Daewoo	Mar-09	Liberia	DRL	GTT	4	Qatar-Atlantic Basin
Al Safliya	210,100	ProNav	Daewoo	Dec-07	Bahamas	DRL	GTT	4	Qatargas II
Al Sahla	216,200	J5	Hyundai	Jun-08	Japan	DRL	GTT	4	Ras Gas III
Al Samriya	261,700	QGTC	Daewoo	Sep-08	Marshall Is.	DRL	GTT	5	Qatargas II
Al Sheehaniya	210,100	QGTC	Daewoo	Feb-09	Liberia	DRL	GTT	4	Qatar-Atlantic Basin
Al Shamal	217,000	Teekay LNG	Samsung	Jun-08	Qatar	DRL	GTT	4	RasGas
Al Thakhira	145,000	Peninsular LNG	Samsung	Sep-05	Bahamas	S	GTT	4	Qatargas
Al Thumama	216,000	J5 Consortium	Hyundai	Apr-08	Japan	DRL	GTT	4	Rasgas
Al Utouriya	215,000	J5	Hyundai	Sep-08	Panama	DRL	GTT	4	RasGas
Al Utourma	215,000	J5	Hyundai	Sep-08	Panama	DRL	GTT	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	GTT	4	Brunei LNG
Amanl	154,800	Brunei-Shell	Hyundai	Nov-14	Brunei	DFDE	GTT	4	Brunei LNG
Aman Bintulu	18,928	Perbadanan / NYK Line	NKK Tsu	Oct-93	Malaysia	S	GTT	3	Petronas
Aman Hakata	18,800	Perbadanan / NYK Line	NKK Tsu	Nov-98	Malaysia	S	GTT	3	Petronas
Aman Sendai	18,928	Perbadanan / NYK Line	NKK Tsu	May-97	Malaysia	S	GTT	3	Petronas
Arctic Aurora	160,000	Dynagas	Hyundai	Jul-13	Marshall Is.	DFDE	GTT	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	GTT	4	Brunei LNG
Arwa Spirit	165,000	Teekay LNG	Samsung	Sep-08	Marshall Is.	DFDE	GTT	4	Various

Aseem	154,850	K Line-Petronet	Samsung	Nov-09	Malta	S	GTT	4	Qatar-India
Asia Endeavour	160,000	Chevron	Samsung	Dec-14	Bahamas	DFDE	GTT	4	Various
Asia Energy	160,000	Chevron	Samsung	Sept-14	Bahamas	DFDE	GTT	4	Various
Asia Excellence	160,000	Chevron	Samsung	Sept-13	Bahamas	DFDE	GTT	4	Various
Asia Venture	160,000	Chevron	Samsung	Sept-17	Bahamas	DFDE	GTT	4	Various
Asia Vision	160,000	Chevron	Samsung	June-14	Bahamas	DFDE	GTT	4	Various
Bahrain Spirit	173,000	Teekay	Daewoo	Sept-18	Bahamas	DFDE	GTT	4	Various
Barcelona Knutsen	173,400	Knutsen	Daewoo	May-10	N.I.S.	DFDE	GTT	4	Various
Bebatic	75,060	Brunei Shell Tankers	Atlantique	Oct-72	Brunei	S	GTT	6	Brunei LNG
Beidou Star	172,000	MOL	Hudong	Oct-15	Hong Kong	DRL	GTT	4	Various
Berge Arzew	138,088	BW Gas	Daewoo	Jul-04	Norway	S	GTT	4	Sonatrach
Bilbao Knutsen	138,000	Knutsen / Marpetrol	IZAR Sestao	Jan-04	Spain	S	GTT	4	Atlantic LNG
Bilis	77,730	Brunei Shell Tankers	La Seyne	Mar-75	Brunei	S	GTT	5	Brunei LNG
Bishu Maru	162,000	K Line-Transpacific	Kawasaki Sakaide	Dec-15	Panama	S	Moss	4	Australia-Japan
Boris Davydov	172,600	Dynagas	Daewoo	Sept-18	Cyprus	DFDE	GTT	4	Yamal LNG
Boris Vilkitsky	172,600	Dynagas	Daewoo	Jan-17	Cyprus	DFDE	GTT	4	Yamal LNG
British Achiever	173,644	BP Shipping	Daewoo	June-18	Isle of Man	MEGI-DF	GTT	4	Various
British Contributor	173,644	BP Shipping	Daewoo	Oct-18	Isle of Man	MEGI-DF	GTT	4	Various
British Diamond	155,000	BP Shipping	Hyundai	Sep-08	Isle of Man	DFDE	GTT	4	Indonesia-Various
British Emerald	155,000	BP Shipping	Hyundai	Jun-07	UK	DFDE	GTT	4	Tangguh LNG
British Innovator	138,200	BP Shipping	Samsung	Jul-03	Isle of Man	S	GTT	4	Various
British Listener	173,644	BP Shipping	Daewoo	June-19	Isle of Man	MEGI-DF	GTT	4	Various
British Mentor	173,644	BP Shipping	Daewoo	July-19	Isle of Man	MEGI-DF	GTT	4	Various
British Merchant	138,000	BP Shipping	Samsung	Apr-03	Isle of Man	S	GTT	4	Various
British Partner	173,644	BP Shipping	Daewoo	Mar-18	Isle of Man	MEGI-DF	GTT	4	Various
British Ruby	155,000	BP Shipping	Hyundai	Jan-08	U.K.	DFDE	GTT	4	Various
British Sapphire	155,000	BP Shipping	Hyundai	Sep-08	Isle of Man	DFDE	GTT	4	Tangguh
British Sponsor	173,644	BP Shipping	Daewoo	Sept-19	Isle of Man	MEGI-DF	GTT	4	Various
British Trader	138,000	BP Shipping	Samsung	Dec-02	Isle of Man	S	GTT	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	GTT	5	Qatargas
BW GDF Suez Boston	138,059	BW Gas	Daewoo	Jan-03	Norway	S	GTT	4	Suez LN
BW GDF Suez Everett	138,028	BW Gas	Daewoo	Jun-03	Norway	S	GTT	4	Suez LNG
BW Integrity	170,000	BW Gas	Samsung	May-17	Singapore	DFDE	GTT	4	FSRU
BW Lilac	173,400	BW Gas	Daewoo	Mar-18	Malta	MEGI-DF	GTT	4	various
BW Magna	173,400	BW Gas-Acu Brazil	Daewoo	Mar-19	Singapore	DFDE	GTT	4	FSRU-Brazil
BW Pavilion Aranda	173,400	BW Gas	Daewoo	Oct-19	Singapore	MEGI-DF	GTT	4	Various
BW Pavilion Leeara	161,880	BW Gas	Hyundai	Feb-15	Singapore	DFDE	GTT	4	Various
BW Pavilion Vanda	161,880	BW Gas	Hyundai	Feb-15	Singapore	DFDE	GTT	4	Various
BW Singapore	170,000	BW Gas	Samsung	May-15	Singapore	DFDE	GTT	4	FSRU
BW Suez Brussels	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GTT	4	Yemen-Atlantic
BW Suez Paris	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GTT	4	Yemen-Atlantic
BW Tulip	173,400	BW Gas	Daewoo	Jan-18	Malta	MEGI-DF	GTT	4	various
Cadiz Knutsen	138,826	Knutsen / Marpetrol	IZAR Puerto Real	Jun-04	Spain	S	GTT	4	Engas
Cape Ann	145,000	Hoegh LNG/MOL	Samsung	May-10	Liberia	DFDE	GTT	4	Various
Castillo de Santisteban	173,600	Elcano	STX	Aug-10	Malta	S	GTT		Various
Castillo de Villalba	138,000	Elcano	IZAR	Nov-03	Spain	S	GTT	4	Sonatrach
Catalunya Spirit	138,000	Teekay LNG Partners	IZAR Sestao	Mar-03	Liberia	S	GTT	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	GTT	4	Australia-China
Cesi Gladstone	174,100	MOL-China LNG	Hudong	Oct-16	Hong Kong	S	GTT	4	Australia-China
Cesi Lianyungang	174,100	MOL-China LNG	Hudong	June-18	Hong Kong	S	GTT	4	Australia-China
Cesi Qingdao	174,100	MOL-China LNG	Hudong	Nov-16	Hong Kong	S	GTT	4	Australia-China
Cesi Tianjin	174,100	MOL-China LNG	Hudong	Sept-17	Hong Kong	S	GTT	4	Australia-China
Challenger FSRU	263,000	MOL LNG	Daewoo	Oct-17	St Kitts	DFDE	GTT	4	Various
Cheikh Bouamama	75,500	Skikda LNG Transport	USC	Jul-08	Bahamas	S	GTT	4	Sonatrach
Cheikh El Mokrani	75,500	Med LNG Corp	USC	Jun-07	Bahamas	S	GTT	4	Sonatrach
Christophe de Margerie	172,600	SCF	Daewoo	Nov-16	Cyprus	DFDE	GTT	4	Various
Clean Energy	150,000	Dynagas	Hyundai	Mar-07	Marshall Is.	S	GTT	4	Various
Clean Force	150,000	Dynagas	Hyundai	Jan-08	Marshall Is.	S	GTT	4	Various
Clean Ocean	155,900	Dynagas	Hyundai	Mar-14	Marshall Is.	DFDE	GTT	4	Various
Clean Planet	155,900	Dynagas	Hyundai	Mar-14	Marshall Is.	DFDE	GTT	4	Various
Clean Vision	160,000	Dynagas	Hyundai	Jun-15	Marshall Is.	DFDE	GTT	4	Various
Cool Explorer	160,000	Thenamaris	Samsung	Oct-13	Bermuda	DFDE	GTT	4	Various
Cool Runner	160,000	Thenamaris	Samsung	May-14	Bermuda	DFDE	GTT	4	Various
Cool Voyager	160,000	Thenamaris	Samsung	Oct-13	Bermuda	DFDE	GTT	4	Various
Corcovado LNG	160,106	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GTT	4	Various
Creole Spirit	174,000	Teekay	Daewoo	Jan-16	Bahamas	MEGI-DF	GTT	4	Cheniere

Cubal	160,400	Mitsui/NYK/Teekay	Samsung	Jan-12	Bahamas	DFDE	GTT	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	GTT	4	Various
Dapeng Star	147,000	China Ships	Hudong	Nov-09	China	S	GTT	4	Various
Dapeng Sun	147,000	China Ships	Hudong	Jul-07	China	S	GTT	4	Woodside Energy
Diamond Gas Orchid	165,000	MOL-Jera	MHI-Nagasaki	Aug-18	Japan	S-gas	Moss	4	US-Japan
Diamond Gas Rose	165,000	MOL-Jera	MHI-Nagasaki	Aug-18	Japan	S-gas	Moss	4	US-Japan
Disha	136,000	Petronet LNG Ltd.	Daewoo	Jan-04	Malta	S	GTT	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	GTT	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
Eduard Toll	172,000	Teekay-CLNG	Daewoo	Dec-17	Bahamas	MEGI-DF	GTT	4	Various
Ejnan	145,000	4J	Samsung	Jan-07	Bahamas	S	GTT		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	GTT	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 Glory	165,000	Tokyo LNG Tankers	JMU	Sept-18	Japan	S	Moss	4	Various
Energy Horizon	177,000	Tokyo LNG Tankers	Kawasaki	Jul-11	Japan	S	Moss	4	Pluto LNG
Energy Innovator	165 000	MOL-Tokyo gas	JMU Tsu	April-19	Japan	TFDE	IHI-SPB	4	Cove Point-Japan
Energy Liberty	165 000	MOL	JMU Tsu	Oct-18	Japan	TFDE	IHI-SPB	4	Various
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
Energy Universe	165,000	MOL-Tokyo Gas	JMU Tsu	Sept-19	Japan	TFDE	IHI-SPB	4	Cove Point-Japan
Enshu Maru	165,257	K Line	Kawasaki	June-18	Japan	S	Moss	4	Various
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	GTT	4	Various
Excel	138,106	Exmar/ MOL	Daewoo	Sep-03	Belgium	S	GTT	4	Various
Excelerate	138,000	Exmar/Excelerate	Daewoo	Oct-06	Belgium	S	GTT	4	Various
Excellence	138,000	GKFF Ltd.	Daewoo	May-05	Belgium	S	GTT	4	Excelerate Energy
Excelsior	138,000	Exmar	Daewoo	Jan-05	Belgium	S	GTT	4	Various
Exemplar	150,900	Excelerate	Daewoo	Jun-10	Belgium	S	GTT	4	Various
Expedient	151,000	Excelerate	Daewoo	Nov-09	Belgium	S	GTT	4	Various
Experience RV	174,000	Exmar/Excelerate	Daewoo	Jul-14	Marshall Is.	DFDE	GTT		Various
Explorer	150,900	Exmar/Excelerate	Daewoo	Mar-08	Belgium	S	GTT	4	Excelerate
Express	151,000	Exmar/Excelerate	Daewoo	May-09	Belgium	S	GTT	4	Various
Exquisite	150,900	Excelerate	Daewoo	Sep-09	Belgium	S	GTT	4	Various
Fedor Litke	172,636	Dynagas	Daewoo	Nov-17	Cyprus	DFDE	GTT	4	Various
Flex Endeavour	173,400	Flex LNG	Daewoo	Jan-18	Marshall Is.	MEGI-DF	GTT	4	Various
Flex Enterprise	173,400	Flex LNG	Daewoo	Jan-18	Marshall Is.	MEGI-DF	GTT	4	Various
Flex Rainbow	174,000	Flex LNG	Samsung	July-18	Marshall Is.	MEGI-DF	GTT	4	Various
Flex Ranger	174,000	Flex LNG	Samsung	April-18	Marshall Is.	MEGI-DF	GTT	4	Various
Fraiha	210,100	J5 Consortium	Daewoo	Sep-08	Marshall Is.	DRL	GTT	4	Qatargas
FSRU Independence	170,000	Hoegh	Hyundai	Feb-14	NIS	DFDE	GTT	4	Various
FSRU Lampung	170,000	Hoegh	Hyundai	May-14	Indonesia	DFDE	GTT	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	GTT	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	GTT	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	GTT	4	Various
Gaslog Geneva	174,000	GasLog	Samsung	Sept-16	Bermuda	TFDE	GTT	4	Shell charter
Gaslog Genoa	174,000	GasLog	Samsung	Jun-18	Bermuda	TFDE	XDF	4	Various
Gaslog Gibraltar	174,000	GasLog	Samsung	Oct-16	Bermuda	TFDE	GTT	4	Shell charter
Gaslog Glasgow	174,000	GasLog	Samsung	Jun-16	Bermuda	TFDE	GTT	4	Shell charter
Gaslog Gladstone	174,000	GasLog	Samsung	May-19	Bermuda	XDF	GTT	4	Various
Gaslog Greece	174,000	GasLog	Samsung	Mar-16	Bermuda	TFDE	GTT	4	Shell charter
GasLog Hongkong	174,000	GasLog	Hyundai	Jun-18	Bermuda	XDF	GTT	4	Various
GasLog Houston	174,000	GasLog	Hyundai	Jan-18	Bermuda	XDF	GTT	4	Various
GasLog Salem	165,000	GasLog	Samsung	Apr-15	Liberia	TFDE	GTT	4	Various
GasLog Santiago	155,000	GasLog	Samsung	Mar-13	Liberia	TFDE	GTT	4	Various
GasLog Saratoga	155,000	GasLog	Samsung	Dec-14	Bermuda	TFDE	GTT	4	Various
Gaslog Savannah	155,000	GasLog	Samsung	May-10	Bermuda	DFDE	GTT	4	Various
GasLog Seattle	155,000	GasLog	Samsung	Oct-13	Bermuda	TFDE	GTT	4	Various

GasLog Shanghai	155,000	GasLog	Samsung	Jan-13	Liberia	TFDE	GTT	4	Various
Gaslog Singapore	155,000	GasLog	Samsung	Jul-10	Bermuda	DFDE	GTT	4	Various
Gaslog Skagen	155,000	GasLog	Samsung	Oct-13	Bermuda	DFDE	GTT	4	Various
Gaslog Sydney	155,000	GasLog	Samsung	May-13	Bermuda	DFDE	GTT	4	Various
Gaslog Warsaw	174,000	GasLog	Samsung	May-19	Bermuda	TFDE	GTT	4	Various
GDF-Suez Global Energy	74,000	Gaz de France	Chantiers	Dec-06	France	DFDE	CS1	4	Sonatrach
GDF-Suez Point Fortin	154,200	LNG Japan	Imabari/Koyo	Feb-10	Panama	DFDE	GTT	4	Various
Gemmata	138,100	Shell Shipping	Mitsubishi Nagasaki	Mar-04	Singapore	S	Moss	5	Shell
Georgiy Brusilov	172,000	Dynagas	Daewoo	Jun-18	Cyprus	DFDE	GTT	4	Yamal LNG
Georgiy Ushakov	172,600	Teekay-China	JV Daewoo	Oct-19	Bahamas	MEGI-DF	GTT	4	Various
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	GTT	4	Various
Golar Arctic	140,645	Golar LNG	Daewoo	Dec-03	Marshall Is.	S	GTT	4	Shell Spot
Golar Bear	160,000	Golar	Samsung	Mar-14	Bermuda	TFDE	GTT	4	Various
Golar Celsius	160,000	Golar LNG	Samsung	Sep-13	Bermuda	DFDE	GTT	4	Various
Golar Crystal	160,000	Golar LNG	Samsung	Oct-13	Bermuda	TFDE	GTT	4	Various
Golar Eskimo (FSRU)	160,000	Golar LNG	Samsung	Jan-15	Bermuda	DFDE	GTT	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.	TFDE	GTT	4	Various
Golar Grand	145,880	Golar LNG	Daewoo	2006	IoM	S	GTT	4	Various
Golar Ice	160,000	Golar LNG	Samsung	Feb-15	Bermuda	DFDE	GTT	4	Various
Golar Igloo (FSRU)	160,000	Golar LNG	Samsung	Oct-13	Bermuda	DFDE	GTT	4	Various
Golar Kelvin	160,000	Golar LNG	Samsung	Jan-15	Bermuda	DFDE	GTT	4	Various
Golar Maria	145,950	Golar LNG	Daewoo	2006	Marshall Is.	S	GTT	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.	TFDE	GTT	4	Various
Golar Seal	160,000	Golar LNG	Samsung	Aug-13	Bermuda	TFDE	GTT	4	Various
Golar Singapore (FSRU)	160,000	Golar LNG	Samsung	June-15	Bermuda	TFDE	GTT	4	Various
Golar Snow	160,000	Golar LNG	Samsung	Jan-15	Bermuda	TFDE	GTT	4	Various
Golar Tundra (FSRU)	160,000	Golar LNG	Samsung	Dec-15	Bermuda	TFDE	GTT	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	GTT	4	Petrobras
Grace Acacia	150,000	Algaet Shipping	Hyundai	Jan-07	Japan	S	GTT	4	Various
Grace Barleria	150,000	Swallowtail Ship	Hyundai	Oct-07	Japan	S	GTT	4	Various
Grace Cosmos	150,000	AGH Shipping	Hyundai	Mar-08	Japan	S	GTT	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	GTT	4	Shell BG
Granatina	140,645	Shell Shipping	Daewoo	Dec-03	Singapore	S	GTT	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	GTT	4	Oman Gas
Hanjin Pyeong Taek	130,600	Hanjin Shipping	Hanjin	Sep-95	Panama	S	GTT	4	Pertamina
Hanjin Ras Laffan	138,214	Hanjin Shipping	Hanjin	Jul-00	Panama	S	GTT	4	QatarGas
Hanjin Sur	138,333	Hanjin Shipping	Hanjin	Jan-00	Panama	S	GTT	4	Oman Gas
Hispania Spirit	140,500	Teekay LNG Partners	Daewoo	Sep-02	Spain	S	GTT	4	Atlantic LNG
Hoegh Esperanza FSRU	170,000	Hoegh	Hyundai	April-18	Norway	DFDE	GTT	4	Various
Hoegh Gallant FSRU	170,050	Hoegh LNG	Hyundai	May-14	Marshall Is.	DFDE	GTT	4	chartered
Hoegh Giant FSRU	170,050	Hoegh LNG	Hyundai	Jan-18	Marshall Is.	DFDE	GTT	4	various
Hoegh Grace FSRU	170,050	Hoegh LNG	Hyundai	May-15	Marshall Is.	DFDE	GTT	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	GTT	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	GTT	4	Oman LNG
Ibri LNG	145,000	Oman Gas	Mitsubishi	Jul-06	Panama	S	GTT	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	GTT	4	Oman Gas
K Freesia	135,256	Korea Line	Daewoo	Jun-00	Panama	S	GTT	4	RasGas
Kinisis	173,400	K-Line	Daewoo	Jan-18	Liberia	MEGI-DF	GTT	4	Various
K Jasmine	145,700	Korea Line	Daewoo	Mar-08	Panama	S	GTT	4	Kogas offtake
K Mugungwha	152,000	K Line	Daewoo	Nov-08	Panama	S	GTT	4	Various
Kita LNG	160,106	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GTT	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	GTT	4	PNG-Asia
Lalla Fatma N'Soumer	145,000	Algeria Nippon Gas	Kawasaki Sakaide	Dec-04	Bahamas	S	Moss	4	Various
Lijmilya	261,700	QGTC	Daewoo	Sep-08	Marshall Is.	DRL	GTT	5	Various
LNG Abalamabie	174,900	Bonny Gas	Samsung	Nov-16	Bermuda	DFDE	GTT	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	GTT	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	GTT	4	Nigeria LNG
LNG Bonny	177,000	Bonny Gas Transport	Hyundai	Oct-15	Bermuda	DFDE	GTT	4	Nigeria LNG
LNG Borno	149,600	NYK Line	Samsung	Aug-07	Japan	S	GTT	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 Dubhe	174,000	MOL-Cosco	Hudong	Sept-19	China	S	GTT	4	Russia-Asia
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	GTT	4	Nigeria LNG
LNG Fimina	175,000	Bonny Gas Transport	Samsung	Oct-15	Bermuda	DFDE	GTT	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	GTT	4	Nigeria LNG
LNG Jamal	135,330	Osaka Gas/J3 Consortium	Mitsubishi Nagasaki	Oct-00	Japan	S	Moss	5	Oman Gas
LNG Juno	177,300	MOL-Osaka	Mitsubishi	Oct-18	Marshall Is.	DFDE	Moss	4	Freeport LNG/Various
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	GTT	4	NLNG
LNG Lagos	177,000	Bonny Gas	Hyundai	Oct-15	Bermuda	DFDE	GTT	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	GTT	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	GTT	4	Nigeria LNG
LNG Mars	155,000	MOL/Osaka Gas	Mitsubishi	Oct-16	Marshall Is.	S	Moss	5	Various
LNG Merak	174,000	MOL-Cosco	Hudong	Nov-19	China	S	GTT	4	Russia-Asia
LNG Ogun	148,300	NYK Line	Samsung	Aug-07	Japan	S	GTT	4	Nigeria LNG
LNG Ondo	148,300	BW Gas	Daewoo	Sep-07	Bermuda	S	GTT	4	Nigeria LNG
LNG Oyo	140,500	BW Gas	Daewoo	Dec-05	Bermuda	S	GTT	4	Nigeria LNG
LNG Pioneer	138,000	MOL	Daewoo	Jul-05	Bahamas	S	GTT	4	Idku
LNG Port Harcourt	175,000	Bonny Gas	Samsung	Oct-15	Bermuda	DFDE	GTT	4	Nigeria LNG
LNG Portovenere	65,000	Exmar	Italcantieri Sestri	Jun-96	Italy	S	GTT	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	GTT	4	Nigeria LNG
LNG Rivers	137,231	Bonny Gas Transport	Hyundai	Jun-02	Bermuda	S	Moss	4	Nigeria LNG
LNG Sakura	177,000	NYK-Kepco	Kawasaki	Mar-18	Bahamas	DFDE	GTT	4	Various
LNG Saturn	153,000	MOL	MHI	Nov-15	Japan	S	Moss	4	Various
LNG Schneeweisschen	180,000	MOL-Itochu	Daewoo	Aug-18	Panama	XDF	GTT	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	GTT	4	Various
Lusail	138,000	Peninsular LNG	Samsung	May-05	Bahamas	S	GTT	4	Qatar
Macoma	173,400	Teekay	Daewoo	Oct-17	Bahamas	DFDE	GTT	4	Various
Madrid Spirit	138,000	Teekay LNG Partners	IZAR Puerto Real	Jan-05	Spain	S	GTT	4	Engas
Magdala	173,400	Teekay	Daewoo	Feb-18	Bahamas	DFDE	GTT	4	Various
Magellan Spirit	165,500	Teekay LNG Partners	Samsung	Sep-08	Denmark	DFDE	GTT	4	Various
Malanje	160,400	Mitsui/NYK/Teekay	Samsung	Jul-11	Bahamas	DFDE	GTT	4	Various
Maran Gas Achilles	174,000	Maran	Hyundai Samho	Feb-16	Greece	DFDE	GTT	4	Various
Maran Gas Agamemnon	174,000	Maran	Hyundai Samho	May-16	Greece	DFDE	GTT	4	Various
Maran Gas Alexandria	161,870	Maran	Hyundai Samho	Sep-15	Greece	DFDE	GTT	4	Various
Maran Gas Amphipolis	173,400	Maran	Daewoo	Aug-16	Greece	DFDE	GTT	4	Various
Maran Gas Apollonia	161,870	Maran	Daewoo	Jan-14	Greece	DFDE	GTT	4	Various
Maran Gas Asclepius	145,000	Kristen Navigation	Daewoo	Jul-05	Bermuda	S	GTT	4	Qatar

Maran Gas Chios	173,548	Maran	Daewoo	March-19	Greece	DFDE	GTT	4	Various
Maran Gas Coronis	145,700	Maran	Daewoo	Sep-07	Greece	S	GTT	4	Rasgas II
Maran Gas Delphi	159,800	Maran	Daewoo	Feb-14	Greece	DFDE	GTT	4	Various
Maran Gas Efessos	159,800	Maran	Daewoo	Jun-14	Greece	DFDE	GTT	4	Various
Maran Gas Hector	174,000	Maran	Hyundai Samho	Nov-16	Greece	DFDE	GTT	4	Various
Maran Gas Hydra	173,617	Maran	Daewoo	Feb-19	Greece	DFDE	GTT	4	Various
Maran Gas Lindos	159,800	Maran	Daewoo	Jun-15	Greece	DFDE	GTT	4	Various
Maran Gas Mystras	155,900	Maran Gas	Daewoo	May-15	Greece	DFDE	GTT	4	Various
Maran Gas Olympias	174,500	Maran	DSME	Feb-17	Greece	DFDE	GTT	4	Various
Maran Gas Pericles	174,000	Maran	Hyundai Samho	June-16	Greece	DFDE	GTT	4	Various
Maran Gas Posidonia	161,870	Maran	Daewoo	May-14	Greece	DFDE	GTT	4	Various
Maran Gas Roxana	173,400	Maran	Daewoo	Jan-17	Greece	DFDE	GTT	4	Various
Maran Gas Sparta	161,870	Maran	Hyundai Samho	April-15	Greece	DFDE	GTT	4	Various
Maran Gas Spetses	174,000	Maran	Daewoo	Feb-18	Greece	DFDE	GTT	4	Various
Maran Gas Troy	155,900	Maran Gas	Daewoo	May-15	Greece	DFDE	GTT	4	various
Maran Gas Ulysses	174,000	Maran	Hyundai Samho	Jan-17	Greece	DFDE	GTT	4	Various
Maran Gas Vergina	173,605	Maran	Daewoo	Dec-2016	Greece	DFDE	GTT	4	Various
Maria Energy	174,000	Tsakos	Hyundai	Mar-15	Marshall Is.	TFDE	GTT	4	Various
Marib Spirit	165,000	Teekay LNG	Samsung	May-08	Marshall Is.	DFDE	GTT	4	Various
Marshal Vasilevskiy	174,000	Gazprom	Hyundai	Russia	Jan-2019	DFDE	GTT	4	Russia-FSRU
Marvel Crane	177,000	NYK-Mitsui	Mitsubishi	Mar-19	Singapore	S	Moss	4	US/Various
Marvel Eagle	155,000	MOL-Osaka	Kawasaki	Sept-18	Marshall Is.	S	Moss	4	Cameron LNG/Various
Marvel Falcon	174,000	NYK-Mitsui	Samsung	Dec-18	Singapore	XDF	GTT	4	Cameron LNG/Various
Marvel Hawk	174,000	NYK-Mitsui	Samsung	Dec-18	Singapore	XDF	GTT	4	Cameron LNG/Various
Marvel Kite	174,000	NYK-Mitsui	Samsung	Dec-18	Singapore	XDF	GTT	4	Various
Marvel Pelican	155,000	MOL-Mitsui	Kawasaki	Dec-19	Marshall Is.	DFD	Moss	4	Cameron LNG-Various
Matthew	126,540	Suez LNG Shiping	Newport News	Jun-79	Bahamas	S	GTT	6	Atlantic LNG
Megara	173,000	Teekay	Daewoo	Oct-18	Bahama	MEGI-DF	GTT	4	Various
Mekaines	266,000	Naklilat	Samsung	Mar-09	Liberia	DRL	GTT	4	Qatar-Atlantic Basin
Meridian Spirit	165,500	Teekay LNG	Samsung	Jan-10	Denmark	DFDE	GTT	4	Various
Mesaimeer	210,100	Naklilat	Hyundai	Mar-09	Liberia	DRL	GTT	4	Qatar-Atlantic Basin
Methane Alison Victoria	145,000	GasLog	Samsung	Aug-07	Bermuda	S	GTT	4	Eq.Guinea LNG
Methane Becki Anne	170,000	GasLog	Samsung	Sep-10	Bermuda	TFDE	GTT	4	Various
Methane Heather Sally	145,000	GasLog	Samsung	Jul-07	Bermuda	S	GTT	4	Eq.Guinea LNG
Methane Jane Elizabeth	145,000	GasLog	Samsung	Jun-06	Bermuda	TFDE	GTT	4	Engas
Methane Julia Louise	170,000	GasLog	Samsung	Dec-09	Bermuda	TFDE	GTT	4	Various
Methane Kari Elin	138,200	Shell	Samsung	Jun-04	Bermuda	S	GTT	4	Various
Methane Lake Charles	145,000	Shell	Samsung	Feb-07	Bermuda	S	GTT	4	Marathon Oil
Methane Lydon Volney	145,000	Shell	Samsung	Aug-06	Bermuda	S	GTT	4	Engas
Methane Mickie Harper	170,000	Shell-GasLog	Samsung	Nov-10	Bermuda	TFDE	GTT	4	Various
Methane Nile Eagle	145,000	Shell-GasLog	Samsung	Dec-07	Bermuda	S	GTT	4	Engas
Methane Patricia Camila	170,000	Shell-GasLog	Samsung	Oct-10	Bermuda	TFDE	GTT	4	Various
Methane Princess	138,159	Golar LNG	Daewoo	2003	UK	S	GTT	4	Spot BG
Methane Rita Andre	145,000	GasLog	Samsung	Mar-06	Bermuda	S	GTT	4	Engas
Methane Shirley Elizabeth	145,000	GasLog	Samsung	Apr-07	Bermuda	S	GTT	4	Marathon Oil
Methane Sprit	165,000	Teekay LNG	Samsung	Mar-08	Singapore	DFDE	GTT	4	Various
Milaha Qatar	145,000	Milaha	Samsung	Apr-06	Denmark	S	GTT	4	Qatar
Milaha Ras Laffan	138,270	Milaha	Samsung	Mar-04	Denmark	S	GTT	4	RasGas II
Min Lu	147,000	China Ships	Hudong	Aug-09	China	S	GTT	4	Various
Min Rong	147,000	China LNG Ships	Hudong	Feb-09	Hong Kong	S	GTT	4	Australia-China
Mourad Didouche	126,130	Hyproc Shipping	Atlantique	Jul-80	Algeria	S	GTT	5	Sonatrach
Mozah	266,000	QGTC	Samsung	Aug-08	Qatar	DRL	GTT	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	GTT	4	Qatar-Atlantic Basin
Murex	173,400	Teekay	Daewoo	Oct-17	Bahamas	DFDE	GTT	4	Various
Murwab	210,100	J5 Consortium	Daewoo	May-08	Marshall Is.	DRL	GTT	4	Qatargas
Muscat LNG	149,170	Oman Gas/MOL	Kawasaki Sakaide	Mar-04	Japan	S	Moss	4	Oman Gas
Myrina	173,000	Teekay	Daewoo	Sept-18	Bahamas	MEGI-DF	GTT	4	Various
Neo Energy	149,700	Tsakos	Hyundai	Feb-07	Liberia	S	GTT	4	Various
Neptune	145,000	Hoegh LNG/MOL	Samsung	Dec-09	Liberia	DFDE	GTT	4	Various
Nikolay Urvantsev	172,000	MOL-China Ships	Daewoo	Nov-19	Hong Kong	DFDE	GTT	4	Yamal
Nikolay Yevgenov	172,600	Teekay	Daewoo	Oct-18	Bahamas	MEGI-DF	GTT	4	Various
Nikolay Zubkov	172,600	Dynagas	Daewoo	Nov-18	Cyprus	DFDE	GTT	4	Yamal LNG
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	GTT	4	NWS
Northwest Swift	127,590	J3 Consortium	Mitsubishi Nagasaki	Sep-89	Japan	S	Moss	4	NWS
Noshu Maru	180,000	MOL-Jera	MHI-Nagasaki	Feb-19	Japan	S-gas	Moss	4	US-Japan
Oak Spirit	173,400	Teekay	Daewoo	Jan-16	Bahamas	MEGI-DF	GTT	4	Cheniere
Ob River	150,000	Lance Shipping	Hyundai	Oct-07	Marshall Is.	S	GTT	4	Various
Oceanic Breeze	155,300	K-Line	Mitsubishi-Nagasaki	June-18	Japan	S	Moss	4	Darwin-Japan
Onaiza	210,100	Nakilat	Daewoo	Apr-09	Liberia	DRL	GTT	4	Qatar-Atlantic Basin
Ougarta	171,866	Hyproc Shipping	Hyundai	Mar-17	Algeria	DFDE	GTT	4	Sonatrach
Pacific Arcadia	147,200	NYK Line	MHI	Oct-14	Bahamas	S	KM	4	Various
Pacific Breeze	182,000	K Line	Kawasaki	Mar-18	Marshall Is.	DFDE	Moss	4	Ichthys LNG
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	GTT	4	Various
Pan Americas	174,000	Teekay	Hudong	Mar-18	Hong Kong	TFDE	GTT	4	US-Asia
Pan Asia	174,000	Teekay	Hudong-Zhonghua	July-17	Bahamas	TFDE	GTT	4	Cheniere
Pan Europe	174,000	Teekay	Hudong	Sept-18	Hong Kong	TFDE	GTT	4	US-global
Papua	171,800	MOL-China	Hudong	Jan-15	Hong Kong	DFDE	SSD	4	PNG LNG
Patris	173,400	K-Line	Daewoo	Feb-18	Liberia	MEGI-DF	GTT	4	Various
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	GTT	4	Petronet
Prism Agility	180,024	SK Shipping	Hyundai	April-19	Panama	DFDE	GTT	5	Various
Prism Brilliance	180,016	SK Shipping	Hyundai	March-19	Panama	DFDE	GTT	5	Various
Provalys	153,500	Gaz de France	Chantiers	Nov-06	France	DFDE	CS1	4	ELNG
Pskov	170,200	SovComFlot	STX	Mar-14	Liberia	DFDE	GTT	4	Various
Puteri Delima	130,400	MISC	Atlantique	Jan-95	Malaysia	S	GTT	4	Petronas
Puteri Delima Satu	137,100	MISC	Mitsui Chiba	Apr-02	Malaysia	S	GTT	4	Petronas
Puteri Firuz	130,400	MISC	Atlantique	May-97	Malaysia	S	GTT	4	Petronas
Puteri Firuz Satu	137,100	MISC	Mitsubishi Nagasaki	Sep-04	Malaysia	S	GTT	4	Petronas
Puteri Intan	130,400	MISC	Atlantique	Aug-94	Malaysia	S	GTT	4	Petronas
Puteri Intan Satu	137,100	MISC	Mitsubishi Nagasaki	Dec-01	Malaysia	S	GTT	4	Petronas
Puteri Mutiera Satu	137,100	MISC	Mitsui Chiba	Apr-05	Malaysia	S	GTT	4	Petronas
Puteri Nilam	130,400	MISC	Atlantique	Jun-95	Malaysia	S	GTT	4	Petronas
Puteri Nilam Satu	137,100	MISC	Mitsubishi Nagasaki	Sep-03	Malaysia	S	GTT	4	Petronas
Puteri Zamrud	130,400	MISC	Atlantique	May-96	Malaysia	S	GTT	4	Petronas
Puteri Zamrud Satu	137,100	MISC	Mitsui Chiba	Apr-87	Malaysia	S	GTT	4	Atlantic LNG
Raahi	136,000	Petronet LNG Ltd	Daewoo	Dec-04	Malta	S	GTT	4	Qatargas
Ramdane Abane	126,130	Hyproc Shipping	Atlantique	Jul-81	Algeria	S	GTT	5	Sonatrach
Rasheeda	266,000	QGTC	Samsung	Jun-10	Liberia	DRL	GTT		Various
Rias Baixas Knutsen	180,000	Knutsen	Hyundai	Aug-19	Spain	MEGI-DF	GTT	4	Various
Ribera del Duero Knutsen	173,400	Knutsen	Daewoo	Nov-10	Nor-NIS	DFDE	GTT	4	Various
Rioja Knutsen	176,300	Knutsen	Daewoo	Dec-16	Nor-NIS	DFDE	GTT	4	Various
Rudolf Samoylovich	172,652	Teekay-CLNG	Daewoo	Oct-18	Bahamas	MEGI-DF	GTT	4	Various
Salalah LNG	147,000	Oman Gas/MOL	Samsung	Dec-05	Japan	S	GTT	4	Oman
SCF Polar	71,500	Sovcomflot	Kockums	Aug-69	Liberia	S	GTT	6	Sonatrach
Sean Spirit	174,000	Teekay	Hyundai Samho	Feb-19	Bahama	MEGI-DF	GTT	4	Various
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	GTT	4	Yemen LNG
Seri Amanah	145,000	MISC	Samsung	Mar-06	Malaysia	S	GTT	4	Yemen LNG
Seri Anggun	145,000	MISC	Samsung	Nov-06	Malaysia	S	GTT	4	Yemen LNG
Seri Angkasa	145,000	MISC	Samsung	Feb-07	Malaysia	S	GTT	4	Petronas
Seri Ayu	145,000	MISC	Samsung	Oct-07	Malaysia	S	GTT	4	Various
Seri Bakti	152,300	MISC	Mitsubishi	Mar-07	Malaysia	S	GTT	4	Petronas
Seri Balhaf	152,000	MISC	Mitsubishi	Sep-08	Malaysia	S	GTT	4	Various
Seri Balquis	152,000	MISC	Mitsubishi	Dec-08	Malaysia	S	GTT	4	Various
Seri Begawan	152,300	MISC	Mitsubishi	Dec-07	Malaysia	S	GTT	4	Various
Seri Bijaksana	152,300	MISC	Mitsubishi	Feb-08	Malaysia	S	GTT	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 Cemara	150,200	MISC	Hyundai	Apr-18	Malaysia	S	Moss	4	Petronas
Seri Cempak	150,200	MISC	Hyundai	Feb-18	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	GTT	4	Atlantic LNG

Sevilla Knutsen	173,400	Knutsen	Daewoo	Jun-10	N.I.S.	DFDE	GTT	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	GTT	5	Qatargas IV
Shen Hai	147,100	China LNG	Hudong Zhonghua	Sep-12	China	AB/CC Steam	GTT	4	Various
Simaisma	147,700	Maran Gas Maritime	Daewoo	Jul-06	Greece	S	GTT	4	Qatar
SK Audace	180,000	SK-Marubeni	Samsung	Jul-17	Panama	XDF	GTT	4	Various
SK Resolute	180,000	SK-Marubeni	Samsung	Jun-18	Panama	XDF	GTT	4	Various
SK Splendor	138,375	SK Shipping	Samsung	Mar-00	Panama	S	GTT	4	Oman Gas
SK Stellar	138,375	SK Shipping	Samsung	Dec-00	Panama	S	GTT	4	RasGas
SK Summit	138,000	SK Shipping	Daewoo	Aug-99	Panama	S	GTT	4	RasGas
SK Sunrise	138,306	I. S. Carriers	Samsung	Sep-03	Panama	S	GTT	4	RasGas
SK Supreme	138,200	SK Shipping	Samsung	Jan-00	Panama	S	GTT	4	RasGas
Sohar LNG	137,250	Oman Gas/ MOL	Mitsubishi Nagasaki	Oct-01	Malta	S	Moss	5	Oman Gas
Sohshu Maru	180,000	MOL	Kawasaki HI	Nov-19	Japan	S-gas	Moss	4	Various-Japan
Solaris	155,000	GasLog	Samsung	Jul-14	Bermuda	TFDE	GTT	4	Various
Sonangol Benguela	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GTT	4	Angola LNG
Sonangol Etosha	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GTT	4	Angola LNG
Sonangol Sambizanga	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GTT	4	Angola LNG
Southern Cross	172,000	MOL	Hudong	May-15	Hong Kong	DRL	GTT	4	Various
Soyo	160,400	Mitsui/NYK/Teekay	Samsung	May-11	Bahamas	DFDE	GTT	4	Various
Spirit of Hela	177,000	MOL	Hyundai	Oct-09	Panama	DFDE	GTT	4	Various
Stena Blue Sky	145,700	Stena	Daewoo	Jan-06	Panama	S	GTT	4	Various
Stena Clear Sky	171,800	Stena	Daewoo	Sep-10	Panama	DFDE	GTT	4	Various
Stena Crystal Sky	171,800	Stena	Daewoo	Jul-10	Panama	DFDE	GTT	4	Various
STX Kolt	145,700	STX Panocean	Korea Hanjin	Nov-08	Panama	DFDE	GTT	4	Various
Suez Point Fortin	154,200	Trinity LNG	Koyo Japan	Nov-09	Panama	S	GTT	4	Yemen LNG
Symphonic Breeze	147,608	K-Line	Mitsubishi Nagasaki	Oct-07	Bahamas	DFDE	Moss	4	Australia-Japan
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	GTT		Tangguh
Tangguh Foja	155,000	K Line	Samsung	Jul-08	Panama	DFDE	GTT	4	Tangguh LNG
Tangguh Hiri	155,000	Teekay LNG	Hyundai	Nov-08	Isle of Man	DFDE	GTT	4	Tangguh
Tangguh Jaya	145,700	K Line	Samsung	Nov-08	Panama	DFDE	GTT	4	Tangguh
Tangguh Palung	155,000	K Line	Samsung	Mar-09	Panama	DFDE	GTT	4	Tangguh
Tangguh Sago	155,000	Teekay LNG	Hyundai	Mar-09	Isle of Man	DFDE	GTT	4	Tangguh LNG
Tangguh Towuti	145,700	Sovcomflot/NYK	Daewoo	Oct-08	Cyprus	S	GTT	4	Tangguh
Tembek	216,200	OSG/Nakilat	Samsung	Sep-07	Marshall Is.	DRL	GTT	4	Qatargas II
Tenaga Satu	130,000	MISC	Dunkerque	Sep-82	Malaysia	S	GTT	5	Petronas
Tessala	171,866	Hyproc Shipping	Hyundai	Dec-16	Algeria	DFDE	GTT	4	Sonatrach
Torben Spirit	173,000	Teekay	Daewoo	Feb-17	Bahama	MEGI-DF	GTT	4	Various
Trinity Arrow	154,900	K Line	Imabari Shipbuilding	Mar-08	Panama	S	GTT	4	Various
Umm Al Amad	210,100	J5	Daewoo	Aug-08	Marshall Is.	DRL	GTT	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	GTT	4	Qatargas
Umm Slaal	266,000	QGTC	Samsung	Nov-08	Qatar	DRL	GTT	5	Qatargas
Valencia Knutsen	173,400	Knutsen	Daewoo	Sep-10	Nor-NIS	DFDE	GTT	4	Various
Velikiy Novgorod	170,200	SovComFlot	STX	Feb-14	Liberia	DFDE	GTT	4	Various
Vladimir Rusanov	172,000	MOL-China Shipping	Daewoo	Mar-18	Hong Kong	DFDE	GTT	4	Yamal
Vladimir Viz	172,000	MOL-China Shipping	Daewoo	Sept-18	Hong Kong	DFDE	GTT	4	Yamal
Vladimir Voronin	172,600	Teekay	Daewoo	Jun-19	Bahamas	MEGI-DF	GTT	4	Various
Wakaba Maru	125,000	J3 Consortium	Mitsui Chiba	Apr-85	Japan	S	Moss	5	Pertamina
WilForce	156,000	Teekay LNG	Daewoo	Aug-13	NIS	DFDE	GTT	4	Various
WilPride	156,000	Teekay	Daewoo	June-13	NIS	DFDE	GTT	4	Various
Woodside Cheney	174,000	Maran	Hyundai Samho	Mar-16	Greece	DFDE	GTT	4	Various
Woodside Donaldson	165,500	Teekay LNG	Samsung	Dec-09	Singapore	DFDE	GTT	4	Various
Woodside Goode	159,800	Maran	Daewoo	Jul-14	Greece	DFDE	GTT	4	Various
Woodside Reeswithers	173,400	Maran	Daewoo	Nov-16	Greece	DFDE	GTT	4	Various
Woodside Rogers	155,900	Maran Gas	DSME	Jul-13	Greece	DFDE	GTT	4	Various
Yakov Gakkel	172,600	Teekay-China JV	Daewoo	Nov-19	Bahamas	MEGI-DF	GTT	4	Various
Yamal Spirit	174,000	Teekay	Hyundai Samho	Jan-19	Bahama	MEGI-DF	GTT	4	Various
Yari LNG	159,983	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GTT	4	Various
Yenisei River	155,000	Dynagas	Hyundai	Jul-13	Marshall Is.	DFDE	GTT	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	GTT	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, Ameris Capital AGF	2010	1	175,000
China	Beihai LNG, Guangxi	Sinopec	2015	4	640,000
	Dalian	PetroChina	2011	3	480,000
	Dapeng ND Guangdong	CNOOC	2018	4	640,000
	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
	Qidong, Jiangsu	Guanghui Energy	2018	1	60,000
	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
	Zhoushan Zhejiang	Enn Group	2018	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
	Tornio	Gasum Skangas	2018	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
Gibraltar	Gasnor	Shell	2018	1	5,000
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
	Mundra	Gujarat State Petroleum, Adani Group	2018	2	320,000
	Kamarajar (Ennore), Tamil Nadu	Indian Oil, DFC, ICICI Bank	2019	2	360,000
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
Jamaica	Montego Bay	New Fortress	2018	1	7,000
Japan	Negishi	Tokyo Gas	1969	14	1,180,000
	Sodegaura	Tokyo Gas JERA Co. Inc	1973	35	2,660,000
	Ohgishima	Tokyo Gas	1998	4	850,000
	Higashi-Ohgishima	JERA Co. Inc.	1984	9	540,000
	Futtsu	JERA Co. Inc.	1985	10	1,360,000
	Yokkaichi LNG	JERA Co. Inc.	1988	4	320,000
	Kawagoe	JERA Co. Inc.	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

LNG Import Terminals (continued)

Country	Location (Project)	Owners	Start up	Storage Tanks	Storage Capacity
	Sakaide	Shikoku Electric, Cosmo Oil	2011	1	180,000
Japan (continued)	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	JERA Co. Inc.	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 SK E&S	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
	Jeju	Kogas	2019	2	90,000
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
Netherlands	Gate LNG	Gasunie, Royal Vopak	2011	3	540,000
Panama	Costa Norte	AES	2018	1	130,000
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
	Mugardos, El Ferrol	Reganosa, Sonatrach, Sojitz Corp.	2006	2	300,000
	El Musel, Gijón,	Enagas	2013	2	300,000
Sweden	Lysekil	Gasum	2014	1	30,000
	Nynashamn	AGA Gas	2011	1	20,000
Taiwan	Yung-An	CPC	1990	6	690,000
	Tai-Chung	CPC	2009	5	800,000
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
	Freeport	Freeport LNG Development	2008	2	320,000
	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	Shenzhen	CNPC Yudean Power	2021	2	120,000
	Tianjin (Nangang)	Beijing Energy	2022	10	2,000,000
	Yangjiang	CNPC Yudean Power	2023	2	120,000
	Zhangzhou Fujian	CNOOC	2022	2	160,000
India	Dhamra Odisha	Indian Oil, Adani, GAIL	2020	2	320,000
	Jaigarh	Hiranandani Group	2019	2	320,000
	Kodinar	Hindustan Petroleum Corp.	2022	1	160,000
Japan	Himuka	Diagas Group-Osaka Gas	2022	1	65,000

LNG FSRU Import Facilities

Country	Location (Project)	Owners	Start up
Argentina	Bahia Blanca GasPort	Excelerate/YPF Repsol	2008
	Escobar GasPort	Excelerate/Enarsa	2011
Bangladesh	Moheshkhali	Excelerate, PetroBangla	2018
	Cox's Bazar	Summit Power International, Excelerate Energy	2019
Brazil	Pecem, FSRU	Petrobras	2009
	Guanabara Bay FSRU	Petrobras	2009
	Salvador, Bahia FSRU	Petrobras	2013
China	Tianjin FSRU	CNOOC, Hoegh, various	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
Jamaica	Old Harbour	Golar FSRU, New Fortress	2019
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, Turquoise FLNG	Etki LNG	2016
	Dortyol FSRU Challenger	Botas	2018
UAE	Ruwais, Abu Dhabi	Gasco (UAE)	2016
	Jebel Ali Port, Dubai	DSA (UAE)	2010

LNG Export Projects

Country	Location/Project	Project Developers	Planned Start Up	Number of Trains	Capacity In MTPA
AUSTRALIA	Pluto LNG expansion	Woodside	2021+	2	10.0
CANADA	Bear Head LNG, Nova Scotia	LNG Ltd.	2024	4	8.0
	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, Petronas	2024	2	12.0
	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, GEPetrol	2020+	1	2.0
INDONESIA	Sengkang LNG	Energy World Corp.	2019	4	2.0
MALAYSIA	Rotan FLNG (Sabah)	Petronas, Murphy Oil	2021	1	1.5
MOZAMBIQUE	Area 1 Onshore	Anadarko Petroleum and partners	2023+	2	10.0
	Area 4 Onshore	Eni and partners	2023+	2	10.0
	Area 4 FLNG	Eni and partners	2022	1	3.4
NIGERIA	NLNG Train 7	NNPC, Shell, Eni, Total	2022+	1	7.0
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	2023+	2	10.0
	Arctic LNG II Siberia	Novatek, Total	2023	3	19.8
USA	Alaska LNG Nikiski	Alaska Gasline Development Corp.	2023+	3	20.0
	Annova LNG, Brownsville	Exelon Corp.	2023+	6	6.0
	Commonwealth LNG, Louisiana	Commonwealth LNG LLP	2023+	8	9.0
	Delfin LNG, Louisiana	Delfin	2023+	3	9.0
	Driftwood LNG, Louisiana	Tellurian, Total and others	2023	6	27.6
	Galveston Bay LNG	NextDecade	2023+	6	27.0
	Golden Pass, Texas	Qatar Petroleum, ExxonMobil	2024	3	15.6
	Jacksonville, St John's River	Eagle LNG, Ferus Natural Gas Fuels	2021+	small	-1
	Jordan Cove, Coos Bay	Pembina Corp.	2024	2	7.8
	Lake Charles, Louisiana	Shell, ETE	2024	3	15.0
	Magnolia LNG	Louisiana LNG Ltd.	2023+	4	8.0
	Port Arthur LNG	Sempra	2023+	2	10.0
	Rio Grande LNG	NextDecade	2023+	6	27.0
	Sabine Pass LNG, Louisiana	Cheniere	2016-19	1	4.5
	Texas LNG Brownsville	Chandra, Meyer, Samsung, others	2023+	2	4.0
	VG LNG (Cameron Parish)	Venture Global	2022	5	12.0
	VG LNG (Plaquemines)	Venture Global	2022	10	20.0
	VG LNG (Delta-Plaquemines)	Venture Global	2024	36	22.5

LNG Exporters

Country	Location/Project	Shareholders	Start up	Liquefaction		Storage	
				Trains	capacity (nominal) mtpa	No. of tanks	Total capacity m³
ABU DHABI	Das Island (Adgas)	ADNOC, Mitsui, BP, Total	1977	2	3.2	3	240,000
(UAE)			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
ARGENTINA	FLNG Tango	Bahia Blanca	2019	1	0.5	1	16,100
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
	Ichthys LNG	Inpex Corp., Total	2018	2	8.9	2	330,000
	Prelude FLNG	Shell, Inpex, Kogas CPC	2019	1	3.5		
BRUNEI	Lumut	Brunei/Shell/Mitsubishi/Total	1972-74	5	7.2	3	176,000
CAMEROON	Hilli Episeyo FLNG	Kribi Perenco	2018	1	1.2	1	125,000
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	Equinor, Total, 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	4	640,000
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	5	22.5	5	800,000
	Cove Point LNG	Dominion Energy	2017	1	5.3	7	695,000
	Cheniere Corpus Christi	Texas Cheniere	2018	2	9.0	3	480,000
	Cameron Hackberry	Sempra, Total, Mitsui, Mitsubishi	2019	2	9.8	3	480,000
	Elba Island Georgia	Kinder Morgan, EIG Energy	2019	10	2.5	5	535,000
	Freeport LNG,Texas	Freeport LNG	2019	2	10.2	3	483,000
YEMEN	Bal-Haf	Yemen LNG, Total, Yemen Gas, Hunt Oil, SK Group, Hyundai	2009	2	6.7	2	320,000


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