Oil and Gas News Briefs
Compiled by Larry Persily
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OPEC+ continues to fall short of production targets

(S&P Global Platts; Feb. 9) - OPEC and its allies continue to underperform their increasingly lofty oil production targets, with the group falling a record 700,000 barrels per day short of its collective quotas in January, according to the latest S&P Global Platts survey. OPEC's 13 countries raised output by just 150,000 barrels per day from December, pumping 28.19 million, while the nine non-OPEC partners, led by Russia, only managed to add a meager 10,000, producing 13.99 million, the survey found.

In all, 14 out of the 18 members with quotas under produced their targets, according to Platts calculations. Despite strong gains from the group's core Gulf members and Russia, along with a resurgent Nigeria, disruptions in several OPEC+ countries, including Venezuela, Kazakhstan, Libya and Iraq, limited the bloc's growth.

The coalition's struggles to keep pace with its monthly 400,000-barrels-per-day quota hikes have drawn a chorus of criticism from customers, including the U.S. and India, who say the group should tap its spare production to bring oil prices down from seven-year highs. However, OPEC+ officials, who plan to meet March 2 to determine April output targets, say prices have overshot levels that current market fundamentals would indicate, driven by rising geopolitical risks in the Ukraine and elsewhere. And they say that many underproducing countries face only temporary setbacks that can be reversed.

Global oil trader says constrained supply, not demand, is the problem

(S&P Global Platts; Feb. 6) - Global oil stockpiles are at "worrisome" levels as waning OPEC+ spare capacity is expected to reach an alarming degree by next year amid higher demand outstripping limited supply, the head of Vitol Asia said on Feb. 6. "Demand is currently making the headlines and supply is the problem," Mike Muller told the Gulf Intelligence daily energy markets podcast.

OPEC+, which has been increasing its production quota by 400,000 barrels a day each month since August, is struggling to meet these levels and that will only compound the supply-demand problem, given that the U.S. oil production capacity has yet to hit pre-pandemic figures, Muller said. "The spare capacity in OPEC+ is really down to two and half to three members now, and month after month the 400,000 barrels per day … is actually in effect at a much, much smaller number than that."

As OPEC+ capacity levels decline, Muller said, the debate “has swung to how soon we need Iranian supply to help alleviate the situation or whether there is a need for more” releases from national strategic petroleum reserves. Fears over the 23-member OPEC+ coalition's waning spare capacity could push oil prices to an even steeper rally after breaking a seven-year high of $90 on concerns of tight supply and geopolitical risks.

High prices spur U.S. oil producers to finally start spending again

(Reuters; Feb. 8) - As U.S. oil rises toward $100 a barrel, producers in some high-cost shale basins are buying properties and adding rigs and frack crews in places that fell silent when prices crashed early in the pandemic two years ago. Benchmark U.S. prices last week topped $93 a barrel, up around 65% in the past 52 weeks and the highest since 2014. U.S. producers are cranking up spending at double-digit rates as fuel demand has soared and fears have waned that OPEC will again punish them by flooding the market with crude.

Some executives say current high prices and relatively low service costs make production economics the best in years. Firms are buying U.S. oil, pipeline and gas-processing rivals in a bet that higher prices will more than cover rising costs of labor and equipment. "Drilling economics today are better than they’ve ever been since the shale revolution started," said Chris Wright, chief executive officer of Liberty Oilfield Services. Closely held companies, in particular, are accelerating output, he said.

Activity is stirring in secondary oil fields like Colorado's DJ Basin, Wyoming's Powder River, Louisiana's Haynesville and North Dakota's Bakken, which last year lost its spot as the second largest U.S. oil region. Spending among U.S. independent producers is up 13% over a year ago, according to analysts at Cowen. "When you look at the oil prices in the Bakken, the prompt price is close to $90 a barrel," said Bob Phillips, CEO of pipeline company Crestwood Equity Partners. "That doesn't happen very often."

Several supply factors could derail speeding $100 oil train

(Bloomberg opinion column; Feb. 8) - The oil market feels like a runaway train speeding toward $100 a barrel. Ask traders in Geneva, Singapore, London and Houston and you hear the same thing: “Buy, buy, buy.” I canvassed the market the past few days, and there are virtually no bears left. It’s a one-way street of high-price forecasts. OPEC+ is behind the curve, adding too little oil too slowly, letting inventories fall to perilously low levels. Yet, when everyone is bullish, I get twitchy. I imagine someone, somewhere, quietly selling — and that contrarian strategy proving to be prescient in a dramatic way.

I know one such contrarian. He has yet to be proven right, but listening to lonely bears is important, if only because you need someone to challenge assumptions. The bear’s name is Ed Morse, Citigroup head of commodity analysis, who last week stuck his head above the parapet, telling clients to sell oil. For now, he is unfazed by the losses on his recommendation. At 80, he says solving the “oil puzzle” is what motivates him to work.

Morse anticipates a sea-change in the second half of the year. He says the market is weeks away from shifting into surplus, and will stay there for 15 to 18 months. The shift is due to rising production from OPEC+, the Permian and other U.S. shale basins, plus Canada and Brazil. Morse isn’t alone warning about a surplus. Last week, Ryan Lance, ConocoPhillips CEO, said the Permian alone may add 900,000 barrels a day in 2022. “I’m absolutely concerned about (it). … If you’re not worried about it, you should be.”

That’s not the only potential supply surprise. The U.S. and Iran appear to be closer to restoring the nuclear deal, paving the way for Tehran to return to the oil market in full. OPEC members Nigeria, Angola and a few others may be at capacity but, if prices rise above $100, other members will come under domestic pressure to pump. Saudi Arabia, the UAE and Iraq can easily add a total of 3 million barrels a day above their output.

Guyana wants better terms on future oil production deals

(Argus Media; Feb. 7) - Guyana will seek better terms in future oil production-sharing agreements than those in its 2016 contract with ExxonMobil and the 2013 agreement with Canadian independent CGX Energy. The government will respect the "sanctity" of the 2016 contract signed by the previous administration with the consortium led by ExxonMobil, although it is "one of the worst ever between a government and an oil company," Natural Resources Minister Vickram Bharrat said last week.

But the terms of the agreement with CGX Energy that expires in February 2023 will be changed, Vice President Bharrat Jagdeo said. The company announced a commercial oil find earlier this month in the shallow-water Corentyne block — the first discovery outside the prolific Stabroek block from which Exxon and partners U.S. independent Hess and Chinese state-owned CNOOC unit Nexen started production in 2019. Current output is about 120,000 barrels per day, with plans to reach 800,000 a day by 2026.

The contracts with Exxon and CGX include a 2% royalty on gross earnings, leading the government to receive 14.5% of initial oil revenues. The government will start to receive higher revenues after the companies recuperate initial development costs. The country's production-sharing deal is "relatively favorable to investors by international standards," the International Monetary Fund said in an April 2018 review. New terms will be applied to successful bidders in auctions of offshore oil blocks in the third quarter of this year.

Earthquakes proliferate in Texas Permian Basin fracking region

(Texas Tribune; Feb. 8) - One local said it sounded like a pickup truck had rammed into their house. Another said it sounded like the air conditioner fell off the roof. A third compared the experience to getting off of a rollercoaster, dizzy and a bit shaky. “In the hardest ones we’ve experienced, there is a bunch of shaking, and the pictures shook off the walls,” said Christina Bock, 45, who lives in Gardendale, a rural community north of Odessa in the heart of West Texas oil and gas country. Earthquakes have dislodged her deck from the house and left cracks in her walls, she said.

More than 200 earthquakes of magnitude 3.0 and greater shook Texans in 2021, double the 98 recorded in 2020, according to a Texas Tribune analysis of data maintained by the Bureau of Economic Geology at the University of Texas Austin. The record seismic activity is largely concentrated in the Permian Basin, the state’s most productive oil and gas region. Studies show the spike in earthquakes is almost certainly a consequence of disposing huge quantities of water deep underground — a common practice by oil companies in the hydraulic fracturing process that can awaken dormant fault lines.

The cheapest and most commonly used way to dispose of “produced water” from fracking is to drill another well and inject it into porous rock formations deep underground. For years, oil companies have loaded those formations with hundreds of millions of gallons of the black watery every day, slowly increasing the pressure on ancient fault lines. An analysis by Rystad Energy provided to The Texas Tribune found that the amount of wastewater injected underground in the Permian Basin quadrupled in a decade, from 54 billion gallons in 2011 to 217 billion gallons last year.

Producers favor long-term LNG sales; European buyers hesitant

(Reuters; Feb. 7) - The threat of disruptions to Europe's gas supply from Russia, in the event the West imposes sanctions if Russia invades Ukraine, has prompted a debate of the need for long-term liquefied natural gas supply contracts. Some big LNG producers, such as Qatar, and energy companies that have long-term contracts say Europe should rely less on spot contracts and more on long-term contracts for its energy needs.

Approximately 70% of LNG trade globally is estimated to be sold via long-term contracts, but in Europe spot and short-term contracts represent 45% to 50%. Long-term contracts can run for between 10 and 25 years. Generally, gas producers want long-term commitments for capacity expansions at capital-intensive projects. Qatar, a top producer, prefers long-term, generally oil-indexed contracts for revenue stability, Luke Cottell, the Europe and Middle East LNG analytics lead at S&P Global Platts, said.

Other producers, such as in the U.S., need long-term contracts to finance their projects, typically selling a chunk of production to traders who take the market risk. But long-term contracts could inhibit free flows of gas in Europe, the European Commission says. As a reaction to single players, such as Russia, being able to take advantage of a dominant position, EU policymakers have encouraged spot trade that allow customers to benefit from lower prices when supplies are abundant. They also avoid customers being locked into using fossil fuel for years as the EU aspires to achieve net-zero emissions by 2050.

[Risk-adverse lenders a challenge for new U.S. LNG export projects]

(Energy Monitor; Feb. 4) - Energy traders are making eye-watering margins selling spot cargoes of liquefied natural gas. Acutely depleted gas storage levels in Europe are keeping LNG spot prices well above seasonal norms. Persistently high prices would indicate a structural shortage, but so far there has been no splurge of capital into new LNG production capacity. The investment cannot be made without demand certainty, and this is fraught with energy transition risks.

Additional greenfield LNG export plants planned for the U.S. Gulf are struggling to secure investment, despite the global gas crunch. A record surge in demand will always prompt operational liquefaction plants to maximize output and make use of any spare production capacity. However, it isn’t enough on its own to underpin commercial capital investment in new LNG plants. That would require revenues guaranteed by a binding contract that commits a buyer to take or pay for the cargoes over a decade or more.

The reason for this is simple: risk-averse lenders. Banks won’t offer project finance to cover construction costs unless an LNG plant pre-sells most (about 80%) of its output under long-term sales and purchase agreements with creditworthy off-takers. Making that commitment is a big ask of some gas buyers, even in today’s overheated market that is screaming for more supply. It requires security of demand at a level that makes a 10- or 20-year contract significantly more cost-effective than spot-market buys. Banks dislike commodity price risk and are reluctant to lend against projects exposed to it.

[U.S. emerges as swing supplier of LNG to the world]

(Reuters column; Feb. 8) - The global liquefied natural gas market is experiencing a short-term shift as Europe sucks up cargoes amid a winter shortage of the fuel, but the long-term implications of the crisis could reshape the industry. Europe's LNG imports hit a record high in January as the continent saw low inventories and insufficient supplies from Russia, whose pipelines usually supply about 40% of the continent's gas demand.

European utilities have responded by buying as much LNG on the spot market as they can, with Refinitiv data showing total January imports at 11.96 million tonnes, up from 8.99 million in December. January cargoes are almost 2 million above the previous record month of 10.09 million in March 2020, according to Refinitiv, which put Europe's total LNG imports in 2021 at 81.3 million tonnes — almost 4 trillion cubic feet of gas.

Much of Europe's additional LNG has come from the United States, which has been adding export capacity in recent years. U.S. LNG exports to Europe were a record 4.98 million tonnes in January, eclipsing the previous high of 4.43 million in December. The January exports to Europe were also four times higher than the 1.29 million tonnes shipped from the United States to the continent in the same month in 2021. The increased shipments to Europe have largely come at the expense of volumes to Asia.

These short-term fluctuations in where LNG is flowing are likely to change in coming months, with spot prices in Asia rising above the equivalent in Europe as major buyers in Japan and China seek more cargoes amid a cold snap. But this winter has shown that LNG has become a flexible fuel and the United States is the key swing supplier.

Sabine Pass LNG capacity will reach 30 million tonnes with sixth unit

(LNG Global; Feb. 7) - Cheniere has announced the substantial completion of Train 6 at the Sabine Pass liquefaction plant in Cameron Parish, Louisiana. The milestone was achieved on Feb. 4. Commissioning is complete and Cheniere's engineering, procurement and construction partner Bechtel has turned over care, custody and control of Train 6 to Cheniere.

A final investment decision was reached for Train 6 in May 2019. The aggregate nominal production capacity of Sabine Pass liquefaction project with all six trains is expected to be approximately 30 million tonnes per year of LNG. The facility will be able to process more than 4.7 billion cubic feet per day of natural gas into LNG.

"With nine total trains across both the Sabine Pass and Corpus Christi (Texas) projects, the Cheniere liquefaction platform is the second-largest in the world," said Jack Fusco, CEO of Cheniere Partners. Sabine Pass liquefaction is adding a third marine berth and supporting facilities to enhance operating flexibility at the terminal. Construction on the third berth is underway, with a targeted completion date in 2023.

Louisiana LNG project closer to loading its first tanker

(Reuters; Feb. 8) - Venture Global LNG received permission on Feb. 8 from federal energy regulators to commission the fourth liquefaction block at the company's Calcasieu Pass LNG export plant in Louisiana. Th tanker Yiannis arrived on Feb. 7 near Calcasieu and could be first to pick up a cargo from the terminal, according to data from Refinitiv. Last week, Venture Global sought permission from the Federal Energy Regulatory Commission to load the first commissioning cargo on or after Feb. 9.

Officials at Venture Global have not yet said whether the Yiannis would be the first tanker to pick up LNG at the facility. After pulling in feed gas from pipelines since around August to test equipment, according to Refinitiv data, Venture Global said Calcasieu started producing LNG around Jan. 19. Venture Global is installing 18 modular liquefaction trains configured in nine blocks at Calcasieu to produce about 10 million tonnes per year of LNG, equivalent to about 1.5 billion cubic feet per day of natural gas. Analysts estimate construction costs at about $4.5 billion.

Venture Global also has started early site work on the $8.5 billion Plaquemines project in Louisiana, which analysts expect to start producing around 2024. Venture Global has entered long-term agreements to sell LNG to several companies around the world, including China National Offshore Oil Corp., China Petroleum and Chemical Corp. (Sinopec), Shell, BP, Edison, Portugal's Galp Energia and Polish Oil and Gas Co.

More LNG tankers available from faster U.S.-Europe runs than Asia

(Bloomberg; Feb. 8) - The cost to transport a shipment of U.S. liquefied natural gas to energy-starved Europe turned negative, a dramatic reversal that illustrates a growing glut of ships in the Atlantic ferrying American fuel. Spot freight rates in the Atlantic crashed to negative $750 per day on Feb. 8, down from $273,000 in early December, according to Spark Commodities, which tracks LNG shipping prices. That's the first time the marker has turned negative in Spark data going back to 2019, and means that — at least theoretically — owners are paying charterers to use their ships.

LNG deliveries to Europe hit a record-high last month as traders redirected shipments toward the continent and away from Asia in order to take advantage of attractive spot prices. The enormous shift in trade flows has meant that there are now too many LNG vessels in the Atlantic Basin. "If your vessels are going to Europe rather than Asia, the trip is much faster so the ships get back sooner and are ready to go again. This creates more availability in the system," said Tim Mendelssohn, Spark managing director.

The negative rate "highlights how current vessel charter payments for the Atlantic Basin do not cover the fuel cost of ballasting the vessel back to the load port," Mendelssohn said. The surge in shipments to Europe has left fewer vessels available in Asia, with freight rates in the Pacific Basin at $16,250 per day on Feb. 8, according to Spark.

Indigenous-led Canadian LNG project starts environmental review

(Natural Gas Intelligence; Feb. 8) - The first Indigenous contender for Canadian liquefied natural gas exports has hired engineering contractors, entered the final stage of environmental review and confirmed a 2023 target date to start building a floating liquefaction plant. Cedar LNG, created by the Haisla Nation at its Kitimat site on the northern Pacific coast of British Columbia, on Feb. 8 said front-end engineering and design would be done by Black & Veatch and Samsung Heavy Industries.

“The Cedar LNG project will be the largest First Nation-owned infrastructure project in Canada, creating jobs, contracting and other economic opportunities for the Haisla Nation, the community of Kitimat, neighboring Indigenous nations, and the local region,” said Haisla Chief Crystal Smith. The project triggered a 180-day review by filing an application with the BC Environmental Assessment Office for its C$3 billion plan to export 400 million cubic feet per day of gas as LNG, mostly from the Montney Shale.

Cedar LNG expects to make a final investment decision in 2023 following completion of the environmental assessment. Provided all regulatory approvals are received, in-service is set for 2027, the sponsors said. The action comes eight months after the Haisla enlisted Calgary-based Pembina Pipeline as a 50% owner and expert operating partner. The deal included a C$90 million commitment by Pembina to cover planning and regulatory costs. Cedar LNG would be built in Kitimat near the C$30 billion Shell-led LNG Canada project, which is under construction and planned for a 2025 start-up.

Canada says no to proposed LNG plant in Quebec

(CBC News; Feb. 9) - Ottawa's rejection of GNL Quebec's liquefied natural gas plant and export project in Saguenay, Quebec, appears to be the final nail in the coffin for the Énergie Saguenay project that was previously denied by the province in July 2021. "It's a great relief for us," said Adrien Guibert-Barthez who lives in Saguenay, a two-hour drive north of Quebec City, and is a spokesperson for Coalition Fjord, a group that actively opposed the project and the impact it would have on the environment.

"It's the first LNG terminal that's been blocked by a government," he said. "It's a big step to end the era of [fossil] fuels." Canada's Minister of Environment and Climate Change, Steven Guilbeault, signed off on a report by the Impact Assessment Agency of Canada on Feb. 7. The report said the project should not go ahead. In an environmental assessment decision statement, Guilbeault said the negative effects the GNL Quebec project would have on the environment were "in no way justifiable."

The $14 billion plan included construction of a liquefaction plant and wharf, with infrastructure to store LNG, load tankers and ship the fuel from a marine terminal near the Grande-Anse port to markets overseas via the St. Lawrence Seaway. Since GNL Quebec started developing the project in 2014, it has faced a chorus of opposition from Indigenous communities, experts and locals, though some saw the project as a way to create jobs and diversify the region's economy. After lengthy consultations and an environmental review, Quebec decided not to let the project go ahead last year.

Demand for carbon pollution permits in Europe drives prices higher

(Bloomberg; Feb. 3) - A supply squeeze driving natural gas prices higher has sent the cost of buying pollution permits in Europe to a record. Carbon futures exceeded 97 euros ($111) a ton and are fast approaching the 100-euro mark that many hedge funds and analysts forecast last year. Higher gas prices are forcing European utilities to burn more dirty coal to keep the lights on this winter, increasing demand for pollution permits.

“Carbon continues to attract a lot of speculative buying interest given its momentum and the political will to see it higher in order to ‘kill’ coal and promote the push toward renewables,” said Ole Hansen, head of commodity strategy at Saxo Bank. European gas prices more than tripled last year, boosting the cost of pollution permits. Carbon has also surged as hedge funds piled in, with bets on rising prices.

Europe is grappling with an energy crunch as Russian gas supplies remain limited as tensions over Ukraine are running high. Lower flows from Europe’s top gas supplier also come at a time parts of Europe are turning colder, with temperatures across the U.K. set to drop below winter norms. So far, the continent has averted the worst predictions for an energy crisis such as rolling blackouts and industrial shutdowns due to mild weather.

Europe grapples with shift to renewable energy amid gas tensions

(ClimateWire; Feb. 7) - Rising natural gas prices and tensions between Russia and Ukraine are forcing Europe to grapple with tough questions about the pace of its energy transition. Europe depends on Russia for more than a third of its gas, but Moscow’s aggression toward Ukraine has stoked fears of interruptions in gas flows if the conflict escalates. That has forced Europe’s leaders to confront the continent’s growing reliance on Russian gas to generate electricity, heat homes and power the industrial sector.

The crisis arrives as Europe moves toward a greener future. Many European countries have moved to shutter coal plants and build wind and solar facilities to slow the upward emissions trend. But gas is still needed because there aren’t enough renewable power sources to replace fossil fuels. “I think Europe is seeing that it’s very hard to shut down coal and in some places nuclear and then not have gas go up,” said Stefan Ulrich, a European gas associate at BloombergNEF. “Even with the strong renewable build-out … you need that thermal generation to meet your energy demand.”

The crisis might push European countries to make their transition to clean energy more quickly, some analysts said. And some European officials have doubled down on their support for the shift. “The current situation underlines again that the clean-energy transition is the only way forward. The challenges we are facing now are the result of our dependency on fossil fuels — in particular on Russian gas. The answer is more green energy, not less,” said Kadri Simson, the European commissioner for energy.

Nuclear power cutbacks in France drive up Europe’s electricity prices

(Bloomberg; Feb. 9) - European power prices jumped after the region’s biggest producer cut its nuclear output target for a second time in a month, the latest sign that this winter’s energy crisis is far from over. German power for March advanced as much as 5.5%, while French prices rose 0.6% on Feb. 7 as Electricite de France cut its power generation forecast for 2022 by as much as 4%.

EDF’s nuclear reactors are the backbone of an increasingly integrated European power system, exporting large amounts of electricity to neighboring grids to help keep the lights on. But the fleet is getting more unreliable because of long periods of planned and unplanned maintenance. Outages, coupled with the lowest natural gas stocks ever for the time of year, sent power prices to record highs in December.

While gas prices have slipped since then, traders remain on edge over a potential lack of supplies during any cold spells for the rest of the winter. Even with nuclear output hampered by technical issues, France was Europe’s biggest net exporter of power in the second half of 2021. Less nuclear in 2022 will probably cut exports to Germany and the U.K., increasing their exposure to high gas and coal prices for its power plants.

Gazprom may tap U.S.-sanctioned field to supply gas to China

(Reuters; Feb. 8) - Russian gas giant Gazprom may tap a field hit by U.S. sanctions off the Pacific island of Sakhalin to provide China with natural gas under a recently signed deal, sources and analysts said on Feb. 8. Russia, already Beijing's No. 3 gas supplier, has been strengthening ties with China, the world's biggest energy consumer, reducing its dependence on its traditional European customers amid a standoff with the West.

President Vladimir Putin announced the deal with China on Feb. 4, which would boost gas exports from Russia's Far East where the pipeline network is not connected to traditional routes of its fuel exports to Europe. Gazprom said it signed a long-term sales and purchase agreement with China National Petroleum Corp. for gas to be supplied via a far eastern route. As the project reaches its full capacity, the amount of Russian pipeline gas supplies to China would grow by 350 billion cubic feet per year.

Gazprom has not revealed the feed gas for the deal, but sources said it may come from fields off Sakhalin, including Yuzhno-Kirinskoye, which Washington put under sanctions in 2015 for Moscow's role in Ukraine. The field, part of the Kirinsky block in the Sea of Okhotsk, also contains oil. The sanctions prevent foreign companies from tapping such fields, and the possible gas exports from Yuzhno-Kirinskoye to China may show that Russia has learned how to get around the sanctions. According to Gazprom's data, Yuzhno-Kirinskoye's reserves amount to 25 trillion cubic feet of gas.

Shell’s floating LNG production unit offline until at least late March

(Western Australia Today; Feb. 7) - Shell is unlikely to return its troubled Prelude floating LNG vessel off the Western Australia coast to production until late March, losing valuable revenue as LNG demand from gas-starved Europe soars. Shell CEO Ben van Beurden said the A$24 billion vessel, which suffered a complete power failure after a small fire on Dec. 2, would be out of action for most of the March quarter.

“Prelude is going through teething troubles,” Van Buerden said. “Quite a few teething troubles, of course, but bearing in mind this is a unique asset with, of course, quite unique challenges.” The December fire cascaded into multiple failures of safety systems on the world’s largest floating vessel that had 293 crew on board. An investigation by the country’s offshore safety regulator concluded the incident could have led to “catastrophic failure” if it had continued aboard the 1,600-foot-long facility.

Van Beurden said Shell had to carefully and comprehensively solve the problems before production could restart. “It’s a remote facility, it’s difficult to get people in,” he said. “It’s not been made easy because of the pandemic as you can imagine.” The Prelude has suffered a series of safety and production problems since mid-2017, when it arrived at its moorings from a South Korean shipyard. At full production, Prelude is designed to ship out 3.6 million tonnes per year of LNG.