Oil and Gas News Briefs
Compiled by Larry Persily
March 4, 2019

Cheniere sends first U.S. LNG cargo to Canada's Atlantic seaboard

(Natural Gas Intelligence; March 1) - Canada's Atlantic seaboard emerged as a customer for natural gas exports from the United States this winter to replace domestic supplies when depleted wells ceased production offshore of Nova Scotia at the end of 2018. Cheniere Energy's Sabine Pass liquefied natural gas export terminal in Louisiana inaugurated the northbound U.S. tanker traffic by sending a cargo to the Canaport LNG import facility in New Brunswick, according to Canada's National Energy Board.

The end to 19 years of production by the Sable Offshore Energy Project and the nearby Deep Panuke platform "will significantly change regional markets," the NEB said. The Canadian Maritimes "will transform from being an exporter of domestic gas to being an importer of gas from the U.S." Canaport, next to Irving Oil's New Brunswick refinery at Saint John, received six cargoes of LNG from Trinidad, Norway and the Netherlands in 2018 as Canada's offshore output went through the last stages of reserves depletion.

LNG cargoes top up northbound U.S. gas flows on the Maritimes & Northeast Pipeline. The line started up in 1999 for Canadian gas exports but was built to be capable of reversing its flow and has been delivering plentiful U.S. gas to Canada since the halt to offshore production. LNG and U.S. pipeline gas are expected to fill the Canadian supply gap until Nov. 1, the target date for new service from the Western Canada provinces to start on TransCanada's cross-country gas Mainline and a new U.S. link.

Canada's Maritimes risk higher prices without local gas supply

(Financial Post; Canada; March 1) – Consumers and businesses in Canada's Maritime provinces already have the highest natural gas bills in the country and that's not likely to get better anytime soon due to an increasingly unsettled East Coast energy sector. At the center of the current unease is the shuttering of Nova Scotia's offshore gas production after the plug was pulled on the Sable Offshore Energy Project in December.

Sable, which began production in 1999, provided a domestic source of gas and delivered $1.9 billion in royalties to the Nova Scotia government during its lifespan. The plant's closure by operator ExxonMobil Canada was preceded by the loss of Encana's Deep Panuke Offshore Gas Project, which was capped in May 2018. The result likely means higher prices for gas in the Maritimes in the short term and possibly much longer if calls for renewed onshore gas development, a contentious but potentially lucrative issue for cash-strapped provincial governments, are not heeded.

New Brunswick Premier Blaine Higgs, a former oil executive, has moved to renew gas development in the province, although a fracking moratorium remains in place. A domestic supply of onshore gas would help shield consumers from rising prices, in part by avoiding tolls to import gas through the 685-mile pipeline that links Nova Scotia and Massachusetts. Maritimes' consumers already pay the highest average residential gas bills in Canada, according to the National Energy Board, with bills averaging $160 a month, roughly double the averages in British Columbia, Alberta, and Saskatchewan.

Energy giants commit to LNG projects without long-term deals

(Australian Financial Review; March 1) - Global energy giants have thrown out the rule book and are forging ahead with several new liquefied natural gas projects without locking in long-term customers, which should ring alarm bells for Australia's relatively small players, said LNG market analyst Fereidun Fesharaki, chairman of consultancy Facts Global Energy. Backers able to finance mega-projects from their own balance sheets include Shell's US$30 billion LNG Canada project and the ExxonMobil/Qatar US$10 billion Golden Pass LNG in Texas. Both have taken final investment decisions.

The profound market change poses huge challenges for smaller companies that need to underpin their investments with long-term contracts, given buyers' reluctance to commit to such deals. "The guys who need customers will have a problem; if they wait to sign contracts they will be too late," Singapore-based Fesharaki said in an interview during a visit to Australia to meet with the boards of Santos and Caltex about LNG, oil, and refining. "Deep pockets win the race," he said.

In addition to Shell and Exxon/Qatar Petroleum, France's Total, Italy's Eni, and Malaysia's national oil company Petronas are all using their own funds to press ahead with LNG projects on the assumption the gas will go into their global portfolio without locking in long-term sales in advance. It's "turning the business upside down," Fesharaki said. "It's the first time in 40 years I have seen the business change so fundamentally." FGE is estimating that after a dearth of new projects in the past few years, some 180 million tonnes of new LNG capacity will get the green light between 2018 and 2022.

Analysts predict new LNG supplies will overwhelm demand 2019-2020

(Reuters' columnist; Feb. 27) - Not even China's voracious appetite for liquefied natural gas may be enough to absorb the additional supplies hitting the market this year, with the price of the fuel potentially a casualty. While China's LNG imports got off to a strong start in 2019, it's unlikely that will match the 41 percent growth experienced in 2018. And the sharp rise in January imports is likely to unwind in coming months as much of the LNG is being used in coal-to-gas switching that runs out of steam as winter ends.

China will likely increase its LNG demand by about 8 million tonnes in 2019, Nicholas Browne, director of Asia gas and LNG at Wood Mackenzie, told an LNG conference in Singapore this week. While other analysts were somewhat more optimistic about the prospect for increased demand from China, none were forecasting that the 15.7-million-tonne jump from 2017 to 2018 would be repeated. The problem for the market is that more than 30 million tonnes of additional LNG supply will be available in 2019.

Poten & Partners head of business intelligence Jason Feer told the LNGgc Asia event that his company expected 33 million tonnes of new supply in 2019, but only 16 million tonnes of extra demand. Browne said about 70 million tonnes of new LNG would reach the market this year and next driven by the full ramp-up of the last of Australia's plants and by the start-up of new U.S. projects. While the demand outlook over the next few years suggests that the new LNG supply will eventually be absorbed, the problem for the industry is 2019, and possibly part of 2020. That could well mean low prices.

Louisiana LNG developer says tariffs, markets could delay decision

(S&P Global Platts; Feb. 27) - Tellurian maintained Feb. 27 its expectation that it will reach a final investment decision and begin construction on its Driftwood LNG export terminal in Louisiana by the end of June. The developer also provided current cost estimates for the terminal, feed gas pipelines and gas assets it intends to add to its portfolio to support the project. In a regulatory filing, however, Tellurian said geopolitical (trade tariffs) and supply-and-demand issues could impact its forecasts and planning.

Under Tellurian's business model, securing sufficient equity investment partnership deals are critical to funding construction of the liquefaction terminal. Customers are being asked to pay an up-front fee for an equity interest in Driftwood Holdings, which will give them the right to LNG from the project. The volume of gas would depend on the size of the equity investment. No firm equity investment deals have been announced.

Besides the terminal, Tellurian has purchased shale acreage to produce some of its own feed gas supplies and it has proposed building three pipelines to move gas to Driftwood as well as to other customers. In the regulatory filing, Tellurian said it currently estimates the total cost of Driftwood LNG at approximately $28 billion, including owners' costs, transaction costs, and contingencies. The filing said the total excludes interest costs incurred during construction of the Driftwood terminal and other financing costs.

Asia spot-market LNG prices down to $6

(Reuters; March 1) - Asia spot-market prices for liquefied natural gas fell to their lowest level in nearly 19 months this week, pressured as buying interest remained slow and as some suppliers brought units back online. Spot prices for April delivery to Northeast Asia are currently around $6 per million Btu, down 20 cents from the previous week and the lowest since Aug. 4, 2017, when they hit $5.90, Eikon data showed. Spot demand from China, the world's second-largest LNG importer, remained slow.

Total shipments of the fuel into Japan, China, South Korea, and Taiwan were at about 15.94 million tonnes in February, down nearly 19 percent from the previous month, shipping data from Refinitiv Eikon showed. While it is common for monthly import volumes to drop in February as peak winter demand tapers off, that marked the biggest monthly decline from January to February since at least 2013, the data showed.

Novatek says it will sell half of Arctic LNG-2 output on spot market

(Reuters; Feb. 27) - Independent Russian gas producer Novatek will sell on the spot market half of the production it gets from the Arctic LNG-2 project, its chief executive said Feb. 27. The company plans to make an investment decision later this year on Arctic LNG-2, targeting start-up by 2023. Full production capacity would be 19.8 million tonnes a year, slightly larger than Novatek's first LNG export terminal, Yamal, just west of the proposed Arctic LNG-2 site in Russian Siberia.

Large LNG projects tend to secure long-term sales commitments for a majority of their output before an investment decision and the start of construction. But increasing volumes of liquefied natural gas are being sold on the spot market, as some buyers shy away from the commitments of long-term contracts and opt for the riskier spot markets.

Novatek wants nuclear icebreakers to keep route open year-round

(Reuters; Feb. 27) - Russian gas producer Novatek wants to use more nuclear-powered icebreakers to keep the Northern Sea Route, a shipping path traversing the Arctic to Asia, open year-round for its liquefied natural gas deliveries, a top executive said Feb. 27. "Our plan is to keep the Northern Sea Route open 12 months a year by 2023-2025 with 100-megawatt-hour nuclear icebreakers," Novatek Chief Financial Officer Mark Gyetvay told delegates at an energy conference.

Novatek operates the Yamal LNG project in Russia. The terminal started shipments in December 2017, sending gas to Asia via the shorter Northern Sea Route during the months when ice is not a hazard. The rest of the time, LNG carriers loaded with gas from Yamal head west, toward Europe, transferring their Asia-bound cargoes for the long voyage to the Far East. Novatek is planning to make an investment decision later this year on a second plant, Arctic LNG-2, as Russia boosts its role in global LNG trade.

Houston company wins pre-FEED work for Pacific Coast LNG project

(Houston Chronicle; Feb. 28) – Houston engineering, procurement and construction company KBR has landed a design contract for a proposed liquefied natural gas export terminal on the Pacific Coast of Mexico. KBR announced Feb. 28 that Mexico Pacific Ltd. awarded the company a contract for pre-front-end engineering and design services for a medium-sized liquefaction plant planned in Puerto Libertad, Sonora.

Located along the Pacific Coast about 250 miles southwest of the border town of Nogales, the export terminal would liquefy gas delivered by pipeline from the Permian Basin of West Texas and New Mexico. Under its contract, KBR will provide pre-FEED services and a cost estimate for the project, proposed at 12 million tonnes per year of output capacity and targeting the Asia market. Actual FEED work could start later in 2019, Mexico Pacific Ltd. President Josh Loftus said in a statement.

Exxon/Qatar venture make large gas discovery offshore Cyprus

(Reuters; Feb. 28) - ExxonMobil added another gas discovery to the East Mediterranean region after finding a gas-bearing reservoir, named Glaucus, offshore Cyprus, but infrastructure bottlenecks and geopolitical disputes mean output from the field could be far off. Exxon, together with partner Qatar Petroleum, estimated in-place gas resources in the reservoir at 5 trillion to 8 trillion cubic feet of gas, a similar order of magnitude to the Aphrodite and Calypso gas finds nearby, also in Cypriot waters.

The region’s gas output has begun to soar thanks to older discoveries finally coming into production. Israel’s Leviathan field, discovered in 2010 with about 22 tcf, will fully come online in November. The 2015 Zohr discovery offshore Egypt with up to 30 tcf is already producing. The new, undeveloped discoveries have prompted Egypt — which has two gas liquefaction plants in need of more supply — to try to establish itself as a regional hub. But for Cyprus, development could be complicated by the government’s dispute with Turkey, which does not recognize its right to develop the resources.

“Glaucus is a giant. It will be one of the biggest discoveries of the year,” said Robert Morris, Wood Mackenzie’s senior research analyst for Europe. But commercialization of the field is “not straightforward,” Morris said. “There is limited space in local markets and existing export infrastructure. And the volume is insufficient for Exxon and its partner Qatar Petroleum to feed a two-train LNG plant — which had been the partnership’s goal,” he said. Exxon may instead look to cooperate with Eni and Total, which also have found gas in the area, to combine resources to feed an LNG export project.

FERC approves commercial operations at Corpus Christi LNG Train 1

(Houston Chronicle; March 1) - Federal officials have given Cheniere Energy permission to put its first production unit at Corpus Christi LNG into commercial service and begin exports. The Federal Energy Regulatory Commission issued a March 1 order giving Cheniere permission to put its liquefaction unit, Train 1 into service, allowing the company to start export shipments from the Texas facility.

Located along the La Quinta Ship Channel in Ingleside, the $15 billion Corpus Christi facility is the first liquefied natural gas export terminal in Texas. Construction started in 2015, with Train 1 completed in November 2018. As part of a months-long-startup and testing process known as commissioning, Cheniere exported two cargoes of LNG from Train 1 to Greece and the United Kingdom in December. With the FERC order in hand, Cheniere can now begin full commercial operations and regular exports at the facility.

Train 1 is just the beginning at Corpus Christi. Cheniere has already begun the start-up process for Train 2 while construction continues at Train 3. In addition to Corpus Christi, Cheniere owns and operates the Sabine Pass LNG export terminal in Cameron Parish, Louisiana, where the company has been exporting gas since February 2016.

FERC approves last segment of Cheniere's new gas pipeline

(Reuters; Feb. 28) - U.S. energy regulators said this week they have given Cheniere Energy approval to build all of the company's roughly $1 billion proposed Midship natural gas pipeline in Oklahoma. In December, the Federal Energy Regulatory Commission authorized Midship to build the first 186 miles of the mainline pipe and associated infrastructure. FERC approved construction of other parts of the pipe in January, and on Feb. 27 approved work on the remaining 13 miles of mainline pipe.

Cheniere, the nation's biggest LNG exporter and biggest consumer of gas, said it expects to complete the project in 2019. It already has started limited work on the pipeline. Midship is designed to deliver 1.44 billion cubic feet per day of gas from the Anadarko Basin to existing pipelines near Bennington, Oklahoma, for transport to U.S. Gulf Coast and Southeast markets, where demand for the fuel for domestic consumption and liquefied natural gas export is growing.

Total U.S. LNG export capacity is expected to rise to 8.9 billion cubic feet per day by the end of 2019 and 10.3 bcf by the end of 2020 from the current level of 5.1 bcf a day. That should make the country the third-biggest LNG exporter by capacity in 2019. Most of the U.S. LNG export terminals, including Cheniere's Sabine Pass in Louisiana and Corpus Christi in Texas, are located or being built along the Gulf of Mexico.

Consultant warns of urgent need for Australia to import LNG

(S&P Global Platts; Feb. 27) - Australia's gas-strapped East Coast needs to urgently start importing liquefied natural gas in order to mitigate a range of risk factors stretching from supply issues to regulatory uncertainties, energy consultancy EnergyQuest said Feb. 27. Its modeling shows gas production in the states of New South Wales, Victoria, South Australia and Tasmania will start falling short of demand by 2022, and that by 2025 annual gas production offshore Victoria will more than halve from current levels.

Gas supply from Queensland would need to increase to fill the gap, and moving that volume would run into pipeline constraints, EnergyQuest said, adding that more Queensland gas would only be a short-term answer. "We expect Queensland gas production to start declining from 2025, due to a shortage of quality gas resources," EnergyQuest CEO Graeme Bethune said. "Queensland also has investment risks."

Maximizing Queensland's coal-seam gas production requires about "1,000 new wells a year at a total cost of A$1 billion to A$2 billion," he said. "The southern states need a new permanent source of gas supply, which can only be met by proposed LNG import projects," EnergyQuest said. There are five LNG import plans on the table. "Timing is critical and it is concerning that the regulatory processes in Victoria and New South Wales are dragging out, delaying decisions … with these new terminals," Bethune said.

Ontario contributes toward small LNG plant for rural communities

(Northern Ontario Business; Feb. 27) - Natural gas deliveries to five communities along Canada's north shore of Lake Superior could start by late 2020. The Ontario government last month said it would provide $27 million toward building a liquefied natural gas plant in Nipigon for distributing gas to communities struggling with onerous energy costs. "In 2015, when a lot of people saw this project, they probably thought this will never fly," said Daryl Skworchinski, chief administrator for the Town of Marathon.

Over the years, residents in Marathon, Terrace Bay, Schreiber, Manitouwadge, and Wawa — total population, about 11,000 — felt they were getting gouged by pricing spikes on fuel oil, propane and electrical power from the grid. An earlier feasibility study estimated trucking LNG into the towns would save municipalities, homeowners and business more than $6 million annually. The area's rugged topography doesn't allow for extending pipelines. The provincial funds will cover about half the cost of the LNG plant.

Northeast Midstream, an Ontario energy developer, will build the liquefaction plant this fall, taking gas from the nearby TransCanada main line. The LNG will be trucked to depots in each community, heated to return it back to gas, and then distributed by short pipelines into individual homes and public and commercial buildings. The Northern Ontario Heritage Fund contributed $3.4 million for the five communities for front-end engineering, First Nations consultation and environmental assessments.

Nearby Terrace, B.C., looks to secure role in LNG Canada work

(Business in Vancouver; Feb. 28) – The Shell-led LNG Canada terminal is being built in Kitimat, British Columbia, but neighboring land-rich Terrace is preparing to act as the staging area for the largest private resource development project in Canadian history. “We have the land,” said Danielle Myles, manager of economic development for the city of Terrace, which has a population of 13,000 and a footprint of almost 30 square miles.

Myles expects Terrace will be the storage and transit depot site for much of the construction work in Kitimat, which is a half-hour drive away. It could also be a western pivot for the gas pipelines running into LNG Canada’s terminal from Dawson Creek and Fort St. John in the northeast. Terrace, unlike Kitimat, has an airport and an established and extensive retail sector — the city is known as the trading center for northwestern B.C. An idea of the momentum can be found in commercial building permits in Terrace, which have soared nearly 300 percent over the past two years, Myles said.

Japanese shipbuilder may take LNG carrier work to China

(Nikkei Asian Review; March 2) - Kawasaki Heavy Industries is weighing plans to construct liquefied natural gas carriers at a newly completed dock in northeastern China, as the Japanese company streamlines its costs amid competition from South Korean rivals. The Dacks shipyard in Dalian, Liaoning Province, completed a second work dock, more than 1,800 feet long, on March 1. The site is operated by Dalian Cosco KHI Ship Engineering, a joint venture of the Japanese firm and China’s Cosco Shipping.

Kawasaki has built LNG carriers in Japan, with a shipyard in the prefecture of Kagawa tapped for high-value vessels. With the opening of the Chinese dock, which boosts construction capacity by 50 percent, the company may choose to build select core components in Japan and handle the rest in China. The potential shift to the new China dock stems from cutthroat competition by Korean shipbuilders, which are bolstered by government subsidies. In Japan, shipyards are smaller and labor costs are higher.

The first dock at the Dalian shipyard has produced 41 vessels, including bulk carriers to transport mineral ores and grains, as well as mega-tankers and containerships. The second dock was being planned when the shipyard opened in 2007. But the company shelved the project due to the 2008 financial crisis and the subsequent decline in ship demand worldwide. The partners decided in 2015 to reinstate the investment plan.

Shale drillers find that spacing wells too close hurts production

(Wall Street Journal; March 3) - Shale companies' strategy to supercharge oil and gas production by drilling thousands of new wells more closely together is turning out to be a bust. What's more, the approach is hurting the performance of older wells, threatening the U.S. oil boom and forcing the industry to rethink its future. Companies in recent years have touted bunching wells in close proximity, greatly increasing the number of wells drawing on a promising reservoir. The added wells would produce as much as older ones, many drillers believed, allowing them to extract more oil and gas overall.

Now the results are coming in, and they are disappointing. Newer shale wells drilled close to older wells are generally pumping less oil and gas than older wells, according to early corporate results. Engineers warn the new wells could produce as much as 50 percent less in some cases. The newer wells often interfere with the output of older wells because blasting too many holes in dense rock formations can damage nearby wells and lower the overall pressure, making it harder for oil to seep out. The moves could potentially cause permanent damage and lower the overall amount recovered.

Known in the industry as the "parent-child" well problem, the issue is surfacing in shale hot spots across the U.S. Most of the tens of thousands of planned new wells will be child wells drilled close to an already producing well. It's one of the primary reasons why thousands of wells drilled in the past five years are producing less than companies forecast to investors, a Wall Street Journal examination of drilling data has found. Many of the largest producers have disclosed they are facing the problem. Some have begun drilling wells farther apart, which means they have fewer total wells to drill on their land.

Alberta eases back on oil production curtailment order

(Financial Post; Canada; Feb. 28) - Alberta's government eased its curtailment order slightly Feb. 28, allowing oil companies to pump more crude. For the second time in as many months, the government has raised the production limits it set for oil producers — this time by 25,000 barrels a day — as it seeks to end the unprecedented action it took in December when it attempted to lift regional oil prices and boost its own royalties.

The revised curtailment order will allow producers in the province to pump a cumulative total of 3.66 million barrels per day beginning in April, roughly 1 percent higher than in

February. Alberta has been criticized by its three largest integrated oil companies — Suncor Energy, Imperial Oil, and Husky Energy — for the production limits. They said it was an unprecedented interference in the market. Suncor, Imperial, and Husky own downstream refineries and can profit when there are wide price differences.

In December, Premier Rachel Notley said the province's treasury had been damaged by record-setting discounts for Western Canadian oil prices against the U.S. benchmark price. Notley ordered production cutbacks of 325,000 barrels per day beginning in January. At the end of that month, she eased the order by 75,000 barrels, saying it had succeeded in clearing oil out of storage in the province and lifting prices. The latest move was for the same reason: oil storage levels were trending down and prices are up.

Enbridge announces one-year delay in Canadian oil pipeline project

(Bloomberg; March 2) - In a major blow to the Canadian oil industry, Enbridge now expects the replacement and expansion of a key oil pipeline to the U.S. to be in service about a year later than expected. The project, previously set to start moving oil in the fourth quarter of this year, is now expected to start up in the second half of 2020, the company said March 1. Construction is delayed because the Minnesota permitting won't be done until November, and federal permits could take as long as 60 days after that.

The delay is a crushing setback for Canadian oil producers, which have suffered from a lack of pipeline space to ship their crude to refineries, cutting deeply into prices. The postponement of the $9 billion Enbridge Line 3 expansion to add 370,000 barrels of daily shipping capacity is the latest in a string of cancelled or stalled Canadian pipelines. TransCanada's Keystone XL line to the U.S. has been on the drawing board for more than a decade amid environmental and landowner opposition. The Trans Mountain expansion to the British Columbia coast has been stalled amid legal challenges.

Replacement and expansion of Line 3 would help ship more crude along a 1,030-mile route from the Alberta oil hub of Hardisty to Superior, Wisc. Construction is finished in Wisconsin and largely completed elsewhere along the route, but not Minnesota.