Oil and Gas News Briefs
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Qatar plans to start LNG production from expansion project in 2023

(Platts; March 19) - Qatar Petroleum expects to begin LNG production from its North Field expansion project by the end of 2023, its CEO said March 19, as the company has awarded the project’s front-end engineering and design contract to Japan's Chiyoda Corp. State-owned Qatar Petroleum is looking to form a joint venture with international partners to deliver the North Field gas output expansion first announced in July 2017.

The project — which follows the lifting of a 12-year moratorium on more development of the offshore North Field — will enable Qatar to raise its LNG production capacity from 77 million to 100 million tonnes per year. "The award of the FEED contract to Chiyoda is a significant milestone in our journey to deliver the first LNG from this new project by the end of 2023," said Qatar Petroleum CEO Saad Sherida al-Kaabi.

Qatar has already consolidated its two LNG companies, Qatargas and RasGas, into one integrated unit as of the start of 2018. The LNG giant — operating as a single company called Qatargas — is expected to lead to annual savings of as much as Riyals 2 billion ($550 million). Qatargas is the world's largest LNG operator, though Australia and later the United States are expected to temporarily pass Qatar until the Persian Gulf nation completes its expansion. Qatar is well placed to compete with other suppliers due to its low costs from co-production of valuable gas liquids from the North Field.

LNG buyers, sellers need to find a way to finance new projects

(Platts; March 21) - LNG leaders from the U.S., Europe and Asia said March 21 that there is an urgent need to bridge the gap between buyers and sellers which has stalled advancement of liquefaction projects that would fill a potential supply shortage expected by the early to middle part of the next decade. The discussion during the CWC World LNG & Gas Series Americas Summit in Houston comes at a pivotal time for the market.

Following two years during which few new LNG projects have been sanctioned, U.S. developers will be making decisions over the next several months and into 2019 whether to build, delay, or scrap their terminal projects, mostly planned for along the Gulf Coast. Whereas fears of an oversupplied market held back projects in the past, today the key considerations are length and price of contracts. "The question is: who will blink first?" said Akos Losz, a senior research associate at Columbia University's Center on Global Energy Policy. "If the buyers blink, then we go back to the long-term deals."

He said if suppliers blink, they might be willing to accept short- or medium-term deals, or if buyers still don't bite, developers might have to find some other way to finance their projects. "If none of this happens, we might find ourselves in a pretty bad situation where we have a supply gap and high prices actually destroy demand," Losz said. Patrick Hughes, an executive for U.S. LNG hopeful NextDecade, said the company would not be able to finance its proposed terminal in Brownsville, Texas, with supply contracts as short as six years, though it might be comfortable in the 15-year range.

U.S. tariffs on Chinese goods could hurt LNG sales

(Houston Chronicle; March 19) - New tariffs on Chinese imports could make it harder for U.S. liquefied natural gas exporters to serve China's booming market and raise billions for the next generation of Gulf Coast LNG facilities. If the Trump administration follows through on plans to impose tariffs targeting roughly $60 billion in Chinese goods per year, the new policy could further complicate a complex relationship and add another layer of risk that could scare investors already jittery about doing business with China.

LNG operators need to line up long-term contracts to gain the financing and investment needed to build their multibillion-dollar export projects. Investors and lenders were already wary about Chinese buyers honoring contracts for the full-length of a 20-year term. A trade war that could drive the Chinese to buy LNG from Australia, the Middle East, or other U.S. rivals only adds to the uncertainty for investors and the projects.

"Contracts with Chinese buyers may be off the table for the next wave of projects," said Katie Bays, an energy investment analyst at Height Capital Markets in Washington, D.C. China's demand for LNG is surging as the government tries to lower the country's carbon dioxide emissions by using gas for power generation instead of coal. China will "clearly be a very important driver for any project that would like to enter service in the near future," Bays said. But tariffs on Chinese goods would exacerbate the obstacles in locking down LNG contracts, especially if China retaliates for U.S. tariffs, she said.

China's plan to boost gas storage could come up short

(Bloomberg; March 19) - While China seeks more natural gas to meet booming demand from its clean-air drive, one part of the supply chain isn't growing fast enough to avoid a repeat of this winter's supply crunch. Large, underground storage caverns are coming into focus as the missing link the world's biggest energy user needs to smooth out gas supply between weak consumption in the summer and heavy demand in the winter.

While China has plans to more than triple storage capacity by the end of next decade, that still might not be enough to keep pace with its growing appetite, said analysts at IHS Markit and Wood Mackenize. "Chronic gas supply tightness will continue to be around because storage capacity won’t be increasing to the point needed to deal with winter peaks,” said Xizhou Zhou, an energy analyst with IHS Markit in Beijing.

China National Petroleum Corp. (CNPC) said the country has storage space equivalent to about 3.3 percent of total annual demand. The government plans to double capacity by 2020, and more than double it again by 2030. That would amount to 4.8 percent and 5.8 percent of demand, based on forecasts from Sanford C. Bernstein. The world average is 11.7 percent, CNPC said. U.S. capacity is equivalent to about 17 percent of annual consumption. “China’s gas storage levels are far lower than more mature gas markets … leaving China exceptionally reliant on LNG imports to manage seasonal demand swings,” said Saul Kavonic, an analyst with Wood Mackenzie in Singapore.

Japanese utility looks to sell LNG after restarting nuclear reactor

(Reuters; March 19) - A Japanese utility that buys liquefied natural gas to feed power plants has turned into a seller of the fuel after it restarted a nuclear reactor, reducing its need for gas and potentially driving down spot-market LNG prices, trade sources said. With more reactors that have been shut since Japan’s 2011 Fukushima disaster likely to restart this year, LNG demand could be further curbed in the country that is the world’s biggest LNG importer, sources said — causing supplies to swell and prices to wilt.

Kansai Electric has offered a spot-market liquefied natural gas cargo for loading in May, three trade sources said March 19. Kansai Electric did not respond to Reuters’ requests for comment. Japan’s nuclear restart process has been riddled with delays due to technical trouble and legal challenges, making it difficult for utilities to know whether they will need replacement fuels like thermal coal or LNG. Kansai Electric restarted the No. 3 reactor at its Ohi plant on March 14 after a delay of about two months.

“They may need to sell their cargo as they restarted their nuclear (reactor) a week ago. ... I believe they will be in a sell position,” said one Japan-based trader. The utility is reselling its contracted volume from the Australia Pacific LNG project, a second trader said. Kansai has a 20-year commitment with APLNG to buy about 1 million tonnes of LNG a year. Masakazu Toyoda, chief executive of the Institute of Energy Economics, Japan, said last October that about five more nuclear reactors will restart by early 2019.

LNG projects may be only solution to Mozambique’s finances

(Reuters; March 19) - Mozambique will meet with its commercial creditors on March 20 in London to present proposals on how to restructure its huge debts, but Eurobond holders and analysts expressed little confidence on how much progress can be made. Shortly after restructuring a Eurobond in 2016, Mozambique’s government admitted to

$1.4 billion of previously undisclosed loans, much of which was spent on building a state tuna-fishing company and enhancing maritime security.

The disclosure prompted the International Monetary Fund and foreign donors to cut off support, triggering a currency collapse and leading to a default. But in the 17 months since then, little progress seems to have been made. The IMF said in a report last month that Mozambique's debt situation had seen a "stark deterioration" due to a delayed fiscal response to a fall in commodity prices, hidden loans and its currency nearly halving in value since the end of 2014. The country's external public debt is seen rising to $13.3 billion this year from $10 billion in 2016, according to the IMF.

The discovery nearly a decade ago of substantial offshore gas reserves has spurred hopes that one of the world's poorest nations could become an exporter of liquefied natural gas — so far the only likely long-term solution to its deep financial problems. "The big bet with Mozambique is do you believe the LNG plants will start on time?" said Greg Smith, a strategist at Renaissance Capital. He said delays to the projects, which are expected to start up around 2023, could make investors think differently.

[It's not likely, but more Russian LNG could end up in New England]

(Energy & Environment News; March 21) - On Jan. 28, the liquefied natural gas carrier Gaselys pulled into a port near Boston after it had loaded up at a storage terminal in the U.K. It came to New England because a series of cold snaps had made gas prices there the highest in the world. This wasn't just any payload. It included gas from a new plant in Russia, Yamal LNG, majority-owned by a Russian company under U.S. sanctions.

In fact, another partly Russian cargo came to Massachusetts this month. "Sanctions? What sanctions?" teased a tweet by RT.com, a Russian state-funded outlet. The gas is legal, said Engie, the French company chartering the ship and whose subsidiary owns the import terminal in Everett, Mass. Engie said U.S. sanctions covered financing for Yamal's construction but there are no prohibitions on buying gas from Yamal's owners.

However, energy experts said it's unlikely the U.S. will become a frequent consumer of Russian gas. The shipments were a freakish concurrence of prices, weather and the Russian project coming online. Nevertheless, the cargoes are a reminder of the choices New England policymakers make. The region is increasingly gas-dependent, getting nearly half of its power from gas. Yet many policymakers are dead-set against new gas pipelines, favoring scaling up renewable energy and phasing out fossil fuels.

For now, sources said, it remains possible that Russian gas will be back in the U.S. "If Russian gas is competitive and in demand, it may well end [up] in the U.S. again," said Morena Skalamera, a researcher at the Belfer Center for Science and International Affairs at Harvard University's John F. Kennedy School of Government.

LNG cargo from new Maryland terminal lands in U.K.

(Platts; March 21) - The first LNG cargo from the newly operational Cove Point terminal in Maryland arrived March 21 at the U.K.'s Dragon terminal, according to S&P Global Platts, only the second cargo of U.S. to land in the U.K. since U.S. shale-gas based LNG exports began in February 2016. The cargo was delivered aboard the Gemmata, which was diverted from its original route toward the Pacific basin and landed in the U.K. at a time when LNG stocks are depleted following two periods of cold weather.

Despite northwest Europe suffering from the late-winter cold, U.S. LNG has still been a rare visitor to the region. Excluding the cargo into Dragon, only two loads of U.S. LNG have landed in the region — in June 2017 to the Gate terminal in the Netherlands and one in July 2017 to the U.K.'s Isle of Grain plant. Both came from Cheniere Energy's LNG terminal in Sabine Pass, La. U.S. LNG supplies into the Gate terminal are set to increase after Austria's OMV in December signed up for supply from Cheniere Energy.

Australia regulator approves offshore gas project to feed LNG plant

(Sydney Morning Herald; March 22) – Australia's offshore petroleum regulator has approved Santos' multibillion-dollar gas development in the Northern Territory, allowing the company to keep gas flowing to the 12-year-old Darwin liquefied natural gas plant. The National Offshore Petroleum Safety and Environmental Management Authority has approved the 25-year Barossa Caldita offshore project. The gas would be used to replace output from Santos' declining Bayu Undan field, which is due to close in 2023.

The approval of Barossa means it will keep the Darwin LNG plant open after the Bayu Undan project ends. Australia-based Fat Prophets analyst David Lennox said while Darwin LNG has been overshadowed by newer LNG projects in the region, it has been a consistent producer. "Santos cut their teeth on LNG at Darwin," he said. "Darwin has been a quiet achiever for a reasonable period of time now." The single-train Darwin LNG plant currently produces about 3.7 million tonnes of LNG per year.

Santos CEO Kevin Gallagher said the regulatory approval gives the company the confidence it needs to begin examining the technical requirements for developing the new gas field and creating an investment timeline. Macquarie Research forecasts a final investment decision next year. Barossa is a joint venture between Santos, at 25 percent, and ConocoPhillips and South Korea's SK Energy, each at 37.5 percent. The Barossa gas field is located about 200 miles to the north of Darwin.

Exxon still assessing damage at Papua New Guinea gas fields

(Reuters; March 21) - A senior ExxonMobil executive said March 21 the company is still assessing damage to its natural gas processing plant in the mountains of Papua New Guinea, knocked out by a strong earthquake last month. A powerful 7.5 magnitude quake struck near Exxon's Hides facility on Feb. 25, halting production at the site. The temblor damaged power infrastructure and led to the closure of the Komo jungle airfield, making access to the remote facility difficult.

Several aftershocks, as well as the remoteness of the gas field and processing plant — more than 435 miles from the liquefied natural gas export facility near the capital, Port Moresby — have made it difficult to assess and repair any damage, making it unclear when production and LNG exports can resume. "We're doing a full assessment right now. … We had a few aftershocks so you have to go through the assessments again up in the mountains to recheck the facilities," said Neil Duffin, president of ExxonMobil's production company, speaking at an oil and gas industry event in Malaysia.

Before the shutdown, Exxon's Papua New Guinea LNG project had been producing at about 20 percent above its nominal capacity of 6.9 million tonnes a year. Exxon has previously said it plans to restart shipments within eight weeks of the shutdown.

Exxon buys LNG cargo to keep Papua New Guinea plant cold

(Reuters; March 19) - ExxonMobil has bought a liquefied natural gas cargo to keep its Papua New Guinea plant cold after a powerful earthquake triggered a halt to gas production last month, several trade sources said March 19. The cool-down cargo could be a first step toward restarting LNG production at the facility ahead of schedule or it may simply be needed to maintain operational readiness, traders said.

Stopping the liquefaction process that condenses gas into a liquid at minus 260 degrees Fahrenheit causes LNG plants to warm up, requiring cargoes to be imported to keep the cryogenic tanks and equipment operational. Exxon's Papua New Guinea project was shut in late February after an earthquake disrupted feed-gas supplies from the gas-producing Highlands region. Exports are expected to resume by early May. The cool-down cargo is for delivery in early April and was bought from BP, the sources said.

Gas supply essential as Britain plans to close coal-fired power plants

(The Times; London; March 19) - On April 21 last year, Britain's energy system reached a milestone in the shift to a cleaner world. For the first time since the Victorian era, the country went an entire day without burning coal for electricity. The policy of phasing out all coal plants by 2025 has won international praise. Yet this month came a reminder of the problems. On March 1, disruptions in gas supply and high demand in frigid weather sent gas prices soaring and the National Grid scrambling to secure enough supplies.

Those polluting coal plants earmarked for imminent closure ran almost flat out to keep the lights on, generating an average of more than 10 gigawatts for eight days straight during the cold snap, according to U.K.-based consultants Wood Mackenzie. Along with record wind farm output in the stormy weather, the coal plants reduced the amount of gas needed for power generation and helped the crisis pass without cutting off supplies.

“Coal came to the rescue,” said Murray Douglas, research director of Wood Mackenzie, “but that coal is going to be disappearing.” With many coal plants expected to close by 2025, gas-fired plants are due to provide the biggest share of capacity. That is fine in theory, but “you still need gas,” Douglas said. “If the gas market isn’t balanced, you can’t run gas-fired power as much as you may need to.” Britain has historically enjoyed plentiful gas supplies thanks to production from the North Sea, pipeline imports and underground gas storage. But all three suffered problems in March, cutting supply short.

Britain says market will decide if more gas storage is needed

(Reuters; March 19) - Britain has rebuffed calls from the gas industry for an urgent review of the country’s gas storage capacity after a cold snap this month triggered warnings of supply shortages and gas price spikes at their highest in at least a decade. Operators of gas storage sites, industries reliant on gas and developers of new storage projects have been asking for an inquiry since November, following the closure of the Rough underground site that provided 70 percent of Britain’s gas storage capacity.

But the government declined to open an inquiry, according to people who attended a March 16 meeting. The government said it is up to the market to decide to invest in new storage or wait to see if supply shortages drive up prices to attract gas from elsewhere. “There is still a level of complacency in the government that despite recent events the best course of action is to just accept these price shocks,” said Clive Moffatt of Moffatt Associates, who attended the meeting and represents storage developers and industry.

The surge in prices this month comes amid increased focus on the security of imports following tension with Russia, one of Europe’s main gas suppliers, as well as fears that Britain’s exit from the European Union could hit imports. Utility company Centrica closed the Rough storage site in June, saying it had become too costly to maintain the 30-year-old offshore site, leaving Britain with storage capacity equivalent to four to five days of winter demand, down from 15 days previously. Gas is used to heat about 80 percent of Britain’s homes and fuels as much as half the country’s electricity generation at times.

Egypt’s gas recovery could be short-lived

(Bloomberg columnist; March 19) - The discovery of Egypt’s giant Zohr gas field in 2015 was heralded as the solution to the country’s energy problems. So why did Egypt cut a deal this year to import gas from Israel, its former enemy? Dolphinus Holdings, a private Egyptian company, agreed Feb. 19 to buy gas from Noble Energy and its partners from Israel’s two largest offshore fields, Leviathan and Tamar. The deal is the latest chapter in an Egyptian gas saga that has gone from triumph to tragedy to tentative renaissance.

Egypt’s problems with gas were long in the making. In 2006, oil companies complained that low regulated gas prices were making new developments unviable. Investment dried up and production plummeted after the 2011 revolution. The country’s two liquefied natural gas facilities had to stop exports. Gas supply cuts to industry, power cutbacks and a turn to expensive oil for fuel compounded the country’s economic woes.

The government was able to get a grip on the problem beginning in 2015. It raised the price it was willing to pay for new deep-water gas, trimmed subsidies to consumers, and began LNG imports. The fast-track development of Zohr, just 2½ years from discovery to production, reflected higher prices offered for the gas and the urgency from the government. Since then, Zohr and other new fields have reduced the need to import LNG. Given that, why the Israeli gas deal? Egypt needs to cover for future demand. The decline of domestic production and surge in demand for power plants means that without new developments Egypt might be a net gas importer again as early as 2021.

Bangladesh to get first LNG delivery next month

(Platts; March 21) - Bangladesh is expected to receive its first liquefied natural gas cargo from Qatar aboard the floating, storage, and regasification unit Moheshkhali LNG on April 23, Nazimuddin Chowdhury, secretary in the Energy and Mineral Resources Division, said last week. "The unit is now in a drydock in Dubai, from where it will leave for Qatar on April 12-13 to load the LNG," another official said. Supply of regasified LNG into the country's national gas grid will start by the end of the month.

The first LNG cargo could supply regasified LNG for about 15 to 20 days, according to state-owned Rupantarita Prakritik Gas Co. Deliveries from Qatar are part of a sales-and-purchase agreement for 2.5 million tonnes of LNG per year, priced at 12.5 percent of the three-month average of a barrel of Brent crude plus a fixed 0.5 percent. That would be around $8 per million Btu of LNG at current oil prices.

Bangladesh is in negotiations with other suppliers and is planning to sign contracts for more than 3 million tonnes a year shortly. The floating import terminal due in the country next month can deliver 3.75 million tonnes of LNG per year. Bangladesh's second LNG import terminal is expected to be commissioned in October.

U.S. net gas exports to Mexico grow to 4.2 bcf a day this year

(Natural Gas Intelligence; March 19) - The outlook for U.S. natural gas prices continues to be bleak but some trends keep the story from being even worse, as the export market to Mexico is looking better all the time, Raymond James & Associates said March 19. Liquefied natural gas exports have gotten the most media attention, but pipeline gas sales to Mexico "have been a much more needle-moving driver" for demand, reported analyst Pavel Molchanov and his team.

"Though the rate of growth in U.S. gas exports to Mexico is slowing, we envision a 50 percent increase from 2017 to 2020," Molchanov said. In 2010, U.S. gas exports to Mexico, net the gas imported, averaged only 0.8 billion cubic feet per day. By 2018, exports had jumped to 4.2 bcf a day. Historically, most of Mexico's gas imports were through LNG, but pipeline gas is "inherently cheaper," Molchanov said. Expanding U.S. infrastructure is moving more gas south from the Eagle Ford Shale and Permian Basin.

Mexico today produces about half of the gas it consumes, with U.S. pipeline and LNG imports covering the gap. Developing Mexico's abundant unconventional gas resources remains a low priority as the incentives are low and the risks high, Molchanov said. "Thus, do not hold your breath for Mexico to develop a meaningful shale gas industry anytime soon," he said.

States question gas-fueled power plants as they look to renewables

(Wall Street Journal; March 18) - Natural gas overtook coal as the top fuel for making electricity in the United States two years ago. But its brief reign is under assault in some parts of the country. State regulators, renewable-energy advocates, and environmental groups are arguing that some existing and proposed gas-fired plants are not needed or should be replaced by renewable energy. In states including Arizona, Michigan, and Massachusetts, the future of gas plants is being questioned.

But nowhere is gas under more fire than in California, where regulators are saying no to new gas plants and are looking to get rid of older ones. Earlier this year, the California Public Utilities Commission directed the state's largest utility, Pacific Gas & Electric, to solicit bids for renewable energy and storage projects to replace three costly gas plants. Power companies in California also recently abandoned plans to build two gas power plants, a result of the state's preference for batteries, wind farms, and solar panels.

California's move away from gas is driven by aggressive environmental goals, including getting 50 percent of its power from renewables by 2030, up from 30 percent today. Gas is under pressure in other states, including Arizona, where regulators last week voted for a nine-month pause on new large gas-fueled plants. Arizona told the state's largest investor-owned utilities that their future plans relied too heavily on gas and should include more renewables, electricity storage and energy efficiency. Michigan's

CMS Energy backed off from plans to expand a gas-fired plant just west of Detroit after residents and environmentalists worried it would worsen air quality.

Drilling success puts downward pressure on U.S. natural gas prices

(Wall Street Journal; March 21) – Natural gas producers should be delighted: A cold winter has furnaces blazing in late March, domestic demand is up, and record volumes are being sold abroad. Yet prices are depressed. A pair of wells in southwest Wyoming helps explain why. This winter, Ultra Petroleum, just months after emerging from bankruptcy, completed two huge wells in the state, drilling down more than 2 miles and sideways 2 miles. Each has produced enough gas to fuel every household in the state.

Ultra's wells — whose initial flows have been among the largest ever in the U.S. — show how prospectors continue to unearth huge troves of gas. That output is offsetting increases in demand and keeping a lid on prices. Many analysts predict average prices will remain below $3 per million Btu for years. That is good for the homeowners, chemical makers and power plants that buy gas. But cheap gas has bedeviled drillers, many of whom are battling low prices by drilling bigger wells in search of efficiencies.

U.S. gas production has averaged 79.63 billion cubic feet a day this year, up nearly 10 percent from 2017's record output. Gas is surging out of West Texas, a byproduct of oil wells in the Permian Basin. Appalachian output is on the upswing as pipelines connect the Marcellus and Utica shales to market. In Louisiana's Haynesville Shale, and now Wyoming, drillers have super-sized wells to lower the cost per unit and better compete.

When Ultra emerged from bankruptcy in 2017, it embarked on a plan to drill horizontal wells. It drilled a gusher, which maxed out at the equivalent of 51 million cubic feet a day. Then another, with more water and sand for fracking, came in at 54.5 million cubic feet a day. "Well performance like this is one of the reasons we aren't optimistic for a natural gas price recovery," said an energy analyst. "There's simply too much supply."

Saskatchewan backs Alberta in oil pipeline fight

(Regina Leader Post; Saskatchewan; March 19) - Saskatchewan's premier is picking up where his predecessor left off by criticizing the federal government and British Columbia government over pipelines. Scott Moe said he would be in support of Alberta turning off the oil taps to British Columbia, and Saskatchewan would not help the westernmost province. Earlier this year, the B.C. government proposed restrictions on oil shipments that would flow through Kinder Morgan's planned Trans Mountain pipeline expansion.

Although Saskatchewan is not connected to the pipeline, Moe said delaying the project hurts his province. "We will always fight for safe and efficient pipelines to be constructed so we can continually move more of … that energy product to ports and preserve the capacity that we have on our rails for things such as our refined fuel properties, such as our potash, and of course our agricultural products, which we are again behind in shipments this particular year," he said.

Moe has asked the federal government "to ensure British Columbia understands (the oil pipeline) has been approved and construction should begin as soon as possible." Alberta and British Columbia are embroiled in a debate over the pipeline expansion to move more Alberta output to a coastal export terminal.