Oil and Gas News Briefs
Compiled by Larry Persily
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Lack of investment decisions risks LNG supply shortage by 2025

(Reuters columnist; May 16) - Liquefied natural gas producers around the globe are once again considering new investments as expectations of a glut in supply wither away in the face of strong, China-led demand growth in Asia. However, given that it takes several years to go from a final investment decision to LNG production, the industry may be acting too late to prevent a supply shortfall by the middle of next decade.

Much of the focus this week at an annual oil and gas conference in Australia was on what projects are viable and how quickly they can be developed. The worry of too much LNG has been turned on its head by the steep growth of China's demand, which leapt 46 percent last year to 38 million tonnes. China's demand continues to grow with first-quarter imports up 59 percent from a year ago to 12.4 million tonnes.

Wood Mackenzie analysts Saul Kavonic and Nicholas Browne, speaking May 15 on the sidelines of the conference, said the global surplus was likely to be as little as 10 million tonnes in the early 2020s. In a total market of more than 350 million tonnes a year, that's really a market more or less in balance. Kavonic and Browne said that by 2025 the LNG market was likely to switch to an annual deficit of about 50 million tonnes, and there simply aren't enough projects being approved to meet the potential supply gap.

In 2017, just one project reached FID — a relatively small floating LNG development in Mozambique. There is also a dearth of shovel-ready projects that can be approved and developed in time for 2025 with the best prospects in the U.S., Canada, and East Africa.

Long-term LNG contracts fall out of favor

(Platts; May 16) - The expected growth in liquefied natural gas supplies in the coming years will mean buyers can do without long-term contracts, leading industry players said May 15 at the Flame gas conference in Amsterdam. Instead buyers can look to either shorter-term contracts or the spot market to meet their needs. Long-term contracts will soon be a thing of the past, said Charif Souki, chairman at U.S. LNG hopeful Tellurian.

"The market has become sufficiently liquid today that a buyer does not need to enter into a long-term contract," said Souki, who turned U.S. Gulf Coast Cheniere Energy from an unsuccessful LNG importer into a successful exporter before he was pushed out of the company. In the next two years, 20 cargoes will be available every day on the spot market, he said. "There is no incentive, no imperative to have a long-term contract," unless a buyer is a large utility that needs the guarantee of supply, Souki said.

Mark Gyetvay, chief financial officer of Russia's Novatek, agreed the long-term contract is under pressure. Novatek, which started up Yamal LNG last December, is looking at offering variable contract lengths — spot, short, or medium — at its second Arctic LNG project. Total's head of gas, Laurent Vivier, said the long-term contract could still have a role. "There could still be a need for long-term contracts to help finance new projects."

Andree Stracke, chief commercial officer at Germany's RWE Supply & Trading, said his company would not be willing to take the risk of a long-term LNG import contract. "A 10-year horizon is the most that we can risk manage," Stracke said.

Gulf Coast LNG developer says buyers want smaller-volume deals

(Reuters; May 14) - Buyers of liquefied natural gas are no longer balking at long-term contracts, but they want to spread their risk by signing smaller-volume deals with multiple producers, the head of Liquefied Natural Gas Ltd. said May 14. Contract talks have picked up significantly this year, and buyers are again willing to sign 20-year contracts, said Gregory Vesey, CEO of the Australia-based firm that is trying to develop the Magnolia LNG project in Louisiana.

While there may be the occasional “odd duck” looking for up to 4 million tonnes a year, most buyers he speaks to want deals for 1 million to 2 million tonnes a year, Vesey said at a gas conference in Vancouver. LNG buyers have been hesitant to sign large, long-term deals in recent years, pushing instead for small, short- to mid-term agreements as they wait for an anticipated glut from new projects in the United States and Australia.

The glut, however, failed to materialize. Meanwhile, demand has taken off, and a lack of final investment decisions on major projects is fanning fears of an LNG shortage as early as the middle of the 2020s. This has buyers actively seeking longer-term deals in order to get projects built, Vesey said. His company wants to have 75 percent of Magnolia’s planned output of 8 million tonnes a year sold before it moves ahead with an investment decision. Vesey said he expects to make that call by the end of the year.

U.S. LNG industry needs to adapt to market, columnist says

(OilPrice.com columnist; May 15) - The United States began exporting liquefied natural gas just two years ago. The U.S. Energy Information Administration projects total LNG export capacity in the country by the end of 2019 will reach 9.6 billion cubic feet of gas per day. If all that capacity is used, the U.S. will become the world’s third-largest LNG exporter after Qatar and Australia. Meanwhile, a lot of final investment decisions on future U.S. export projects have been delayed for lack of long-term buyer commitments.

The delay in final investment decisions has to do with abundant global LNG supply and buyers' preference for spot or short-term deals. It's a buyers' market, and buyers want the best deal, which is never a long-term deal. It makes sense that investors are uneasy about committing billions for new LNG projects when there is no long-term clarity about demand. Yet it seems that short-term contracts will continue to dominate the market, so they are probably something LNG project developers just need to get used to.

Meanwhile, the competition is intensifying. Qatar is boosting production to hold its No. 1 spot in the global market as LNG projects in Australia are ramping up production. A third issue is stable gas prices for U.S. power generators. If too much gas is sent abroad, this could actually lead to a domestic shortage, which is what happened in Australia. The Australian gas shortage is a lesson for the U.S. LNG export industry, which needs to be flexible in its contracts, lower costs to be competitive, and keep in mind domestic needs.

Equatorial Guinea may drop LNG developer if it cannot get financing

(Reuters; May 14) - Equatorial Guinea will force Ophir Energy out of the company's flagship liquefied natural gas project and may scrap it entirely unless long-delayed financing deals worth $1.2 billion are presented to the government by December. The ultimatum is a blow to U.K.-listed Ophir, which has set aside $150 million of its own cash to develop western Africa's first deepwater LNG project, Fortuna, by 2022 despite the company's lack of a track record in LNG and small balance sheet. Its only producing asset is in the Gulf of Thailand, averaging 11,700 barrels of oil equivalent a day in 2017.

Ophir's license to the Equatorial Guinea gas fields expires in December. It partnered with shipping company Golar LNG and oil services firm Schlumberger on the venture, using a largely untested technology to cut costs. Most LNG plants are land-based — Equatorial Guinea's onshore liquefaction plant started up in 2007 — but Golar's design shrinks the production into a single 1970s-built ship with four liquefaction units bolted to its sides. Ophir wooed Asian lenders but is scrambling after financing talks with Chinese players collapsed last year. Talks with other Asian lenders are underway.

Negotiations with the Industrial and Commercial Bank of China ran into trouble over the bank's demands, sources said. The bank wants the entire output of 2.2 million tonnes a year sold to China National Offshore Oil Corp., and it wants engineering, procurement and construction contracts to go to state-owned firms. Chinese lenders are stepping up their investment in LNG projects, using loans as hooks to secure gas and construction work. "Whoever pays is the boss," said Equatorial Guinea's hydrocarbons minister.

China may yet succeed in its shale gas ambitions, columnist says

(Financial Times columnist; London; May 13) - The natural gas market is changing fast. Global trade in liquefied natural gas has doubled in the past 10 years. The United States, once seen as a major importer, is now an exporter because of all its shale gas. Then there is China, where gas demand has grown from 2 percent of total energy demand in 2000 to more than 6 percent. Crucially, most of this increase is supplied by imports. China is now the world's second largest importer of LNG. In such a complex market the best approach is to watch closely a few factors that can swing the outcome.

The first is Chinese demand for imported gas, which has been the decisive driver in the market. Will that continue? A further rise in demand seems certain. China wants to improve its air quality while maintaining economic growth. But the pace of change is less certain. The conventional wisdom is that China's push to produce its own shale gas has failed and that overall domestic gas output is likely to decline, boosting imports. I am not convinced. As the U.S. experience in shale has demonstrated, persistence pays off. I would not be surprised to see Beijing meet and even exceed its shale ambitions.

The most important limitation will come from Beijing's strategic view of its place in the world. There is some evidence that the surge in gas imports this past winter surprised China's leadership. The country was ill-prepared to meet the heavy demand for gas as it moves away from coal, causing local gas shortages and price spikes. It is hard to see that being allowed to continue. Demand will grow but that growth will be managed.

Shell-led LNG Canada 'so very close' to investment decision

(Platts; May 15) - Shell-backed LNG Canada is "so very close" to reaching a final investment decision for its proposed export terminal in Kitimat, B.C., and expects to begin construction by the end of 2018, CEO Andy Calitz said May 14. The news during the Canada Gas & LNG Conference in Vancouver came as a Chevron executive said Kitimat LNG, a second export project planned for the same coastal area, needs to lower its costs further before moving forward and cannot provide a timetable for reaching FID.

The contrasting postures of the two Western Canada projects reflect the differing views of market economics among developers and the level of risk they are willing to take at a time when global prices remain uncertain and future projections of global demand, while positive, vary from operator to operator. "The time for LNG Canada is now," Calitz told industry leaders at the conference. The project — with an initial capacity of 13 million tonnes a year — is a joint venture of Shell, PetroChina, Korea Gas, and Mitsubishi.

Meanwhile, Kitimat LNG, backed by Chevron and Australia's Woodside, continues to invest development funds and is working to lower costs on its project of 10 million tonnes per year. It isn't able to say when it will make its investment decision, said Rod

Maier, a Chevron vice president of government and public affairs. "We believe further cost reductions are required to be globally cost competitive." Chevron is still smarting from billions of dollars in overruns tied to its Gorgon LNG project in Australia.

LNG Canada working to resolve federal tariff on steel imports

(Globe and Mail; Canada; May 16) - The chief executive officer of LNG Canada said conditions are ripe for the consortium to start building a liquefied natural gas project in British Columbia by the end of this year. Andy Calitz said May 15 that the group, led by Shell, has been making steady progress in the 22 months since plans were suspended to construct an export terminal in Kitimat, B.C.

"We will be in construction in 2018. I reaffirm that commitment today," Calitz said during the Canada Gas and LNG Conference in Vancouver, though the partners have yet to make a final investment decision on the project which is estimated at up to US$40 billion for the liquefaction plant, marine terminal, pipeline, and gas field development.

Calitz said he is optimistic about gaining tariff relief from the federal government. Slashing costs such as federal anti-dumping duties on imported fabricated industrial steel components will figure prominently in whether the Kitimat proposal is deemed attractive enough to approve, industry analysts caution. Susannah Pierce, director of external relations at LNG Canada, said discussions are going smoothly with the federal Finance Department over how to resolve the issue of anti-dumping duties of up to 45.8 percent on imports of steel components, primarily targeted at China and South Korea.

If LNG Canada goes ahead, pipeline construction would start in 2019

(Reuters; May 16) - Construction on TransCanada's C$4.8 billion (US$3.8 billion) Coastal GasLink pipeline will start in early 2019, pending a positive final investment decision on the Shell-led LNG Canada project, the head of the pipeline project said May 16. The comments followed a commitment from the CEO of LNG Canada on May 15 that the C$40 billion liquefied natural gas export terminal would be under construction in 2018. A final investment decision from the project partners is expected this year.

"We would be looking at constructing in the early part of 2019," Coastal Gaslink President Richard Gateman told reporters at an LNG conference in Vancouver. "We could be doing a little bit of field work in the fall (of 2018), if there's an FID decision." TransCanada's 415-mile Coastal GasLink pipeline will cross two mountain ranges to connect rich shale fields in Alberta and northeast British Columbia with the proposed LNG Canada export terminal in Kitimat, on British Columbia's northwest coast.

If the project goes ahead, it will be a game changer for Canadian producers which currently face steep discounts for their gas because of sagging demand in the United States that has plenty of its own gas and a lack of overseas markets. TransCanada expects to award contracts for construction to four consortiums within the next two months, Gateman said. Those contractors will be a mix of local and international players with experience building in mountainous terrain, he said.

Sharing LNG project risk could help with financing, economist says

(Forbes columnists; May 14) - Liquefied natural gas developers need to do more to encourage end users to switch from diesel and other fuels to LNG to help build market demand. A new business model could help. A University of Houston oil-and-gas economist and graduate student propose a broad collaborative that includes producers, engineering and construction companies, equipment manufacturers, pipeline companies, and end users to accelerate market growth by building new LNG export projects.

China and India both suffer from appalling air quality and would benefit by switching from coal to gas in power generation. However, coal extraction is a major employer in both countries, and there are political risks in switching too fast. China and India will want to negotiate low LNG prices based on coal economics. Meanwhile, in the medium term, the industry must find innovative ways to expand global LNG demand by providing end users with incentives to encourage a switch from oil to gas.

Absent long-term contracts with high-credit counterparties, it’s almost impossible for an independent developer to finance the huge investment required for a new project. And there is reluctance among traditional buyers to commit to long-term contracts. A solution is needed. Though it may be difficult to negotiate, we propose spreading the financial risk between all the players — gas producers, pipelines, contractors and equipment — which, in aggregate, should have sufficient credit to support project financing.

Australia LNG developers learned costly lesson of non-cooperation

(Bloomberg; May 16) – Australia’s energy industry, looking back on an era of waste, is now preaching the gospel of thrift and collaboration as it tries to attract more investment in an age of fiscal discipline. Firms like Shell are bemoaning the erosion of shareholder value from the go-it-alone mentality during the $200 billion splurge on LNG projects the past decade. Chevron and Woodside Petroleum have now proposed a massive offshore gas pipeline in Western Australia which could be shared by several companies.

That approach contrasts with the “spaghetti junction” of crisscrossing pipelines built in the past decade as ventures approached projects independently, said energy analyst Martin Wilkes. "Everyone in the industry is feeling the scars from the lack of cooperation,” Graeme Bethune, a consultant with EnergyQuest, said in Adelaide.

Collaboration was missing last decade. In Queensland three LNG plants built adjacent to each other shared virtually no infrastructure such as jetties. In northern Australia two gas fields that are connected to each other are being developed as separate projects. In Western Australia, gas pipelines splay out from offshore fields, crisscrossing each other as they connect to four different liquefaction plants on the mainland and an island.

Projects in Western Australia and Queensland cost about $36 billion more than they would have if companies had collaborated, according to a 2016 study by Perth-based RISC Advisory. "If we rewind 10 years, the original plan always should have been collaboration, but it wasn’t favored,” said Saul Kavonic, a Wood Mackenzie analyst.

Australian producers plan to bring more gas to LNG plants

(Platts; May 16) - The last of Australia's wave of seven new liquefied natural gas export projects are set to start operations by the end of this year, making it the world's largest LNG exporter by the end of the decade, surpassing Qatar. And though analysts don’t expect Australia to see any new greenfield projects in the coming years, development of additional gas supplies for existing export terminals could bring more gas to market.

Australia’s Woodside is leading some of the big expansions, with decisions expected in the next two to three years. Earlier this year, Woodside took control of the Scarborough gas field, about 200 miles offshore Western Australia, by acquiring ExxonMobil's 50 percent interest. It now has a 75 percent interest in Scarborough and plans to connect the supply to its Pluto LNG export facility, which started up in 2012 with a production capacity of 6 million tonnes per year. A final investment decision is expected by 2020.

Woodside's second brownfield project is to develop the Browse basin to backfill the North West Shelf Project, one of Australia's oldest LNG plants. The first of the project’s five liquefaction trains started up in 1989. The Browse development is expected to clear FID by 2021. Apart from Woodside, Adelaide-based Santos is developing a brownfield project to boost Darwin LNG with a backfill from the Caldita Barossa gas field. Darwin was Australia’s second LNG project. ConocoPhillips is the majority interest holder and operator of the Bayu-Undan gas field that feeds the plant.

Australian power company may team up with Japanese LNG buyer

(Bloomberg; May 14) - Australia, soon to become the world's biggest exporter of liquefied natural gas, is turning to the largest buyer, Japan, as it seeks to import the fuel to ease a domestic supply crunch. In a scenario played out previously by LNG exporters including Indonesia and Malaysia, Australia is seeking to import gas to help ease local supply imbalances exacerbated by its growing export industry.

Australian Industrial Energy, which plans to build an import terminal in New South Wales, has sought help from Japan's JERA, a gas-buying colossus that's using a global oversupply of the fuel to transform the North Asian nation's role from biggest buyer to a budding trader. JERA's role in the Australian project has not been decided and a feasibility study is underway, according to a spokesman.

Import plants are also planned for other states on Australia's eastern seaboard, where gas shortages are forecast as production declines from aging fields. AGL Energy, the country's largest electricity generator, plans to purchase up to 2 million tonnes of LNG annually by 2021 to fill a supply gap it sees emerging in the next few years. Gas prices in the East Coast market could rise 30 percent over the next five years, driven mainly by declining low-cost domestic supply, Wood Mackenzie consultants reported May 15.

Higher prices, lower costs push drillers to look outside the Permian

(Wall Street Journal; May 14) – Shale drillers are ramping up production as oil prices rise, moving beyond the West Texas oil field that became the country's drilling center. From Oklahoma to North Dakota, companies are increasing investment in fields that fell out of favor several years ago, as $70 crude makes fracking and horizontal drilling economical in more places again. While the Permian Basin in Texas and New Mexico remains the fastest-growing shale spot, congested pipelines and shortages of labor and materials there are crimping profits, making other fields attractive alternatives.

"Last year it was all about, 'How much can you put in the Permian?'" said Daniel Romero, an analyst with the energy consulting firm Wood Mackenzie. "But now a few months later, it's what else are you doing outside of the Permian?" Drillers flocked to the Permian because it was the least expensive place in the U.S. to produce oil by fracking, thanks to existing infrastructure and oil-bearing rock stacked like a layer cake. Output has surged to roughly 3 million barrels of oil a day — similar to the output of Kuwait.

But rig counts have been rising elsewhere, too, as oil prices have gradually recovered. The number of drilling rigs in several basins outside the Permian has more than doubled. The areas include North Dakota's Bakken, the Eagle Ford in South Texas, and the Cana Woodford in Oklahoma, home to fields known as the Scoop and the Stack. While top-tier land in the Permian's Delaware Basin sold for an average of more than $33,000 an acre last year, property in the Scoop and Stack cost roughly half as much.

U.S. propane exports averaged 905,000 barrels a day in 2017

(U.S. Energy Information Administration; May 15) - In 2017 the United States exported 905,000 barrels a day of propane with the largest volumes going to meet petrochemical feedstock demand in Asia, the U.S. Energy Information Administration reported May 14. Four of the top five importing countries for U.S. propane are in Asia — Japan, China, South Korea, and Singapore. They imported about half of U.S. propane exports.

U.S. propane exports to these four countries doubled between 2015 and 2017, displacing supplies from the Middle East as well as regional production of propane from refineries and natural gas processing plants, the federal agency said.

This source of demand, combined with a large and sustained U.S. price discount to the international market, encouraged large investments in propane export capacity. Between 2010 and 2017 U.S. propane exports grew by 796,000 barrels per day. The fuel is used mainly for space heating and as a petrochemical feedstock and, to a much smaller extent, for transportation and agriculture. Propane is used by the petrochemical industry as a feedstock for producing primarily ethylene and propylene.

Statoil completes name change to Equinor

(Houston Chronicle; May 16) - Norwegian energy major Statoil officially changed its name May 16 to Equinor. Moving away from the word "oil" with growing investments in renewable energy, the new name combines "equal" to reflect its corporate values and more balanced portfolio with "Norway" to maintain its roots and pride. "Some changes are so profound that they challenge us to find a new balance," the Equinor website states. "As we go from being an oil and gas company to a broad energy company, it was natural to change our name."

In recent years, Statoil had emerged as a pioneer in offshore wind farms and, most recently, on the floating wind turbines that can be built even farther offshore where the winds are stronger. The company also recently began investing in solar energy in South America. Equinor plans to invest up to 20 percent of its capital in renewable energy by 2030. Statoil was formed by the government more than 45 years ago to take advantage of Norway's oil and gas resources in the North Sea.

Canada offers to protect investors in disputed oil line project

(The Canadian Press; May 16) - Kinder Morgan Canada's CEO said he appreciates Canadian Finance Minister Bill Morneau's announcement that the government will compensate investors in the proposed Trans Mountain oil pipeline expansion if "unnecessary delays" push costs higher. Morneau said the government is willing to "provide indemnity" to investors to ensure the controversial Alberta-B.C. work proceeds.

Last month, the company said it would stop all non-essential spending on the US$7.4 billion expansion project to triple to 890,000 barrels a day the volume of oil flowing from Alberta to the West Coast. Kinder Morgan has said that construction will not restart unless there are sufficient assurances by the end of this month that it can proceed. The British Columbia government is fighting the expansion, while Alberta supports it and wants the federal government to order its neighboring province to cooperate.

At a press conference May 16, Morneau said the federal government has a "clear role" to play in quelling the "politically motivated investment risk" posed by continued delays from B.C. Premier John Horgan. "We believe that what Premier Horgan has done is unconstitutional," Morneau said. The finance minister had been in intensive talks with Kinder Morgan officials, but the two sides have yet to declare any common ground on the amount of federal money that might be involved to protect investors.