# Oil and Gas News Briefs
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## Canadian agency rules LNG project modules subject to import tariffs

(Reuters; Nov. 23) – Canada’s Border Services Agency said Nov. 23 that the production modules for a liquefied natural gas export terminal near Vancouver should be subject to hefty import tariffs on certain steel elements, a blow to the C$1.6 billion (US$1.2 billion) project. In its decision, the agency said the Fabricated Industry Steel Components (FISC) of an LNG module are not transformed when non-FISC elements are connected, and therefore the 45.8 percent anti-dumping tariffs on the components should apply.

"We're reviewing the ruling and evaluating our options," said a spokeswoman for Woodfibre LNG, the project developer. The company can appeal the ruling to Canada’s International Trade Tribunal. Woodfibre had hoped the border agency would determine the modules were not covered in a 2017 order by a Canadian trade court that found certain FISC from China, South Korea, and Spain were being dumped into the Canadian market, harming local manufacturers. Construction is expected to start on Woodfibre LNG early next year, with first gas in 2023 from the 2.1-million-tonne-per-year facility.

Woodfibre argued that its modules should not be subject to the tariffs as they are not basic steel structures, but rather manufactured goods that include "a myriad of complex and specialized machinery." It said applying the tariffs to the modules would be like applying sugar tariffs to the import of bottled soda. Woodfibre and other Canadian LNG projects have argued that the modules are complex units that have never been built in Canada, with the vast majority of production concentrated in specialized yards in Asia.

Back in October, Canadian Prime Minister Justin Trudeau assured Shell that its C$40 billion LNG project in Kitimat, British Columbia, where site work has started, would not be hindered by the same steel import duties. LNG Canada worries the tariffs could hit the 140 modules — each as tall as a 10-story building and weighing as much as 10 jumbo jets — that the project plans to import from China. LNG Canada is challenging the duties in court. The Federal Court of Appeal is expected to issue a decision soon, which, if the court finds for the project developer, could help Woodfibre LNG in its case.

## Algeria wants to boost LNG production and sales in Asia

(S&P Global Platts; Nov. 22) - Algeria's state-owned Sonatrach hopes to boost its LNG exports to Asia — the world's strongest-growing demand center — in the coming years in an effort to diversify its export destinations and make more use of its liquefied natural gas production capacity.  Sonatrach's marketing vice president, Ahmed el Hachemi Mazighi, said at a Paris event Nov. 22 that while Europe would remain its key export market for both pipeline gas and LNG, the company hopes to grow its sales to Asia.

Europe currently accounts for 95 percent of Algeria's 1.8 trillion cubic feet of gas exports per year.  Mazighi said boosting sales in Asia and increasing total volumes would reduce Europe's share of Algeria’s exports to two-thirds — with Asia at a third.  "Asia represents a beautiful diversification opportunity for Sonatrach," he said.  Sonatrach plans to use its spare liquefaction capacity to produce LNG targeted at Asian markets. Algeria’s four LNG plants, which have a total output potential of more than 25 million tonnes per year, are operating at 72 percent capacity, allowing for more exports in the future.

To further its Asian ambitions, Sonatrach has recently commissioned two new larger LNG carriers, allowing for more economic deliveries to more distant locations.  Most of Sonatrach's fleet is comprised of smaller vessels that tend to shuttle between Algeria and Europe.  But there are also challenges in building a bigger market share in Asia, he said.  These include competition from Australia and the U.S., as well as variations in demand between large utility buyers and "niche" clients that only require small volumes.

## LNG importers group sees supply gap in early 2020s

(S&P Global Platts; Nov. 22) - The global LNG market could move into a state of undersupply earlier than expected, the head of an international association of importers warned Nov. 22. Jean-Marie Dauger, speaking at the Petrostrategies gas conference in Paris, said the LNG market was "covered" for the next few years given the expected start-up of several new supply projects.  But a shortage of final investment decisions for new supply trains in the past few years has left the market potentially undersupplied.

"The supply gap may develop sooner than expected — in the early 2020s, not the mid-2020s," said Dauger, of the International Group of Liquefied Natural Gas Importers. Conference speakers painted an optimistic picture for future demand, with Total's head of gas Philippe Sauquet pointing to an estimated growth rate of 4 to 5 percent per year over the current 300 million tonnes per year.  "We are in a very typical commodity market — when there is oversupply, prices fall and demand responds," he said.

In the first nine months of 2018, China’s LNG imports were up 11.5 million tonnes compared with the same period of 2017, said Geoffroy Hureau, the head of industry group Cedigaz (International Association for Natural Gas).  And there has been strong demand growth in South Korea, India, and Pakistan in the first nine months of 2018, with their combined volume increase on par with Chinese growth, Hureau said.

## Yamal LNG starts up production at third train

(S&P Global Platts; Nov. 22) - Russia's Novatek has begun commissioning production from its third liquefaction train at the Yamal LNG project in the Russian Arctic, a senior company official said Nov. 22. Novatek deputy chairman Lev Feodosyev said production was underway, though he declined to comment on the timing for the first export cargo. The most recent guidance from Novatek on the start-up of the third and final large-volume train at the $27 billion project had been before the end of the year.

Once fully operational, the third train will bring capacity at Yamal to 16.5 million tonnes per year. A micro-train, at 1 million tonnes per year, is set to be commissioned in 2019, bringing the total capacity to 17.5 million tonnes. Novatek's partners include France's Total, China National Petroleum Corp., and China's Silk Road Fund.

Novatek also is close to making a final investment decision on its second gas liquefaction plant — Arctic LNG-2 — with a production capacity of 19.8 million tonnes per year. The first train at Arctic LNG-2 is due online in 2022/2023 with the second and third trains to follow in 2024 and 2025, Feodosyev said. Novatek has said it expects to bring down costs for its second project with estimates that Arctic LNG-2's construction cost could come in at 20 percent less per tonne of capacity than Yamal LNG.

## Yamal LNG cargo transferred to conventional carrier off Norway

(Reuters; Nov. 22) - A liquefied natural gas carrier is transferring a cargo from Russia's Yamal LNG project to another ship at Norway's northern tip, the first such maneuver to help Yamal boost production. The Vladimir Rusanov, an Arc7 ice-breaking LNG carrier, and the lower Arctic-classed Pskov carrier are anchored off Honningsvag, according to Refinitiv Eikon data. "I can confirm there is an ongoing ship-to-ship operation in the area," the Norwegian Coastal Administration's regional director said Nov. 22.

Novatek, which operates Yamal, has been ramping up production after loading its first cargo a year ago, but output has been constrained by the availability of Arctic-classed vessels to make the long deliveries. Now it looks likely that ship-to-ship transfers will become a regular occurrence. Transfers to other LNG carriers free up the ice-breaker LNG vessels to return sooner to Yamal in remote Siberian waters to load up cargoes.

The constraint on Yamal is easing as more Arc7 LNG carriers come into service. Fifteen of the costly vessels were ordered for Yamal, with eight in operation, two at sea trials and five still under construction. The carriers have been taking cargoes to Britain, France, and the Netherlands and have either unloaded there or transferred the LNG to conventional carriers for onward journeys, sometimes to Asia. Permanent reloading terminals are planned in Kamchatka in Russia's Far East and near Norway, but they will not be completed before year 2022. The ship-to-ship reloading is a temporary solution.

## Argentina finds answer to starting LNG exports next year

(Reuters; Nov. 21) - Argentina is due to begin exports of liquefied natural gas from its vast Vaca Muerta shale gas resource next year through a floating LNG liquefaction vessel provided by Exmar, the Belgian shipping company said Nov. 21. The operations, due to start in the second quarter of 2019, will introduce Argentina into the small club of about 20 countries exporting LNG. The floating liquefaction plant can produce 500,000 tonnes per year of LNG, making it the smallest such unit in the world.

The country's state-controlled oil company YPF signed a 10-year agreement with Exmar to deploy the barge-based facility, formerly known as the Caribbean FLNG, at Bahia Blanca on the coast about 400 miles south of Buenos Aires. The 472-foot-long facility was built in China and was destined to work off the coast of Colombia until the small Canadian producer on the project canceled the deal in 2016. Putting it to work will allow Argentina to "take full advantage of the seasonal opportunity with Asian markets and our unique location to serve demand centers," YPF President Miguel Gutierrez said.

Separately, Pan American Energy, Argentina's second-biggest oil and third-largest gas producer, is working with BP on potentially exporting more LNG by sending Vaca Muerta gas through an existing pipeline to Chile and adding liquefaction and exports to an existing LNG import terminal in that Pacific coast country. Vaca Muerta is similar to the shale gas deposits that have rejuvenated the U.S. energy industry. The Argentine play is one of the largest reserves of unconventional hydrocarbons on the planet.

## Pakistan advises LNG importers to renegotiate long-term contracts

(S&P Global Platts; Nov. 22) - Pakistan's competition watchdog has advised liquefied natural gas importers to renegotiate their long-term contracts, warning against prices indexed to crude as the price disparity between oil-linked contracts and LNG spot-market values is widening. The warning came as LNG spot prices have fallen below long-term oil-linked contracts ahead of Asia's peak winter season, an unusual trend driven by comfortable Asian stockpiles of LNG, lower-than-expected Chinese demand and additional supplies from two new megaprojects in Australia and the United States.

In a preliminary assessment issued last week, the Competition Commission of Pakistan advised importers to renegotiate existing contracts and revise their supply negotiation strategies looking forward. It suggested stakeholders consider alternative pricing indexations such as Europe's gas benchmark, the U.S. Henry Hub gas benchmark or the Japan-Korea Marker established by S&P Global Platts. The issue is not exclusive to Pakistan. The risk of pricing LNG against oil has resulted in numerous contract disputes between Indian buyers and global suppliers such as Qatar, ExxonMobil, and Gazprom.

The commission also recommended LNG buyers negotiate for floor and ceiling prices to protect buyers against volatility, while reducing the time between price reviews from the current 10 years to lessen the disparity between contract and spot prices.  LNG imports are part of Pakistan's plan to change its electricity feedstock landscape by replacing gasoil and fuel oil with natural gas to reduce the country's electricity bill and improve its air quality.  Pakistan's LNG imports are expected to grow from 4.9 million tonnes in 2017 to nearly 24 million tonnes by 2023, according to S&P Global Platts Analytics.

## Shell joins Conoco in selling stake in gas project to East Timor

(Reuters; Nov. 21) - East Timor has agreed to buy Shell's stake in the Greater Sunrise gas fields off the northern coast of Australia for $300 million, the government and Shell Australia said Nov. 21.  The agreement for Shell's 26.56 percent stake in the project will allow the tiny nation to push harder for development of the field.  The site, which was discovered in 1974, straddles the maritime border between Australia and East Timor. Disputes between the two countries over the border has delayed development.

The deal comes after ConocoPhillips last month sold its 30 percent stake in the project. Remaining partners include Australia's Woodside Petroleum and Japan's Osaka Gas. The border issue between Australian and East Timor was settled earlier this year.  East Timor wants to develop Greater Sunrise by piping gas to a proposed liquefied natural gas plant on its south coast, while the project partners have favored piping the gas to an existing plant with spare capacity in Darwin in northern Australia.

The Greater Sunrise partners have argued the Timor option would be unprofitable. Analysts remain skeptical about prospects of the field being developed within the next 10 years, as the parties still need to negotiate fiscal terms and tolling agreements. However, if other parties get involved, such as China and South Korea, development might go ahead.  The Sunrise and Troubadour fields, together known as Greater Sunrise, hold about 5.1 trillion cubic feet of gas and 220 million barrels of condensate.

## LNG project will transform B.C. economy for 'years to come'

(The Globe and Mail; Canada; Nov. 20) - British Columbia's economy is forecast to shine for several years as construction starts on a C$40 billion liquefied natural gas project in the northern part of the province.  Last month Shell and its partners in LNG Canada approved the megaproject, which includes a gas liquefaction plant and marine export terminal in Kitimat and a C$6.2 billion 416-mile gas pipeline.

"The construction of the Shell-led LNG Canada project plant in Kitimat is set to positively transform the regional economy for years to come," Bryan Yu, deputy chief economist at Central 1 Credit Union, said in a 31-page report released Nov. 20.  Yu said northwest B.C. will benefit from the early construction phase for LNG Canada's Kitimat terminal, while northeast B.C. starts to thrive from robust drilling for gas. Northern B.C. will turn from being an economic laggard to the driving force in the province, Yu said.

Laid-off skilled workers in Alberta's oil patch should be able to land LNG-related jobs in northern British Columbia, Yu said. LNG Canada's ripple effects will be significant across B.C. and will have a bit of spillover into Alberta, said economist Philip Cross, a senior fellow at Resource Works, a research group. "Services benefit from increased demand for inputs from various industries needed to boost gas production, including everything from engineering to accounting services," Cross said last week.

## U.S. shale oil growth a bad dream for OPEC

(Bloomberg; Nov. 21) - The map lays out OPEC's nightmare in graphic form. An infestation of dots, thousands of them, represent oil wells in the Permian basin of West Texas and a slice of New Mexico. In less than a decade, U.S. companies have drilled 114,000 wells. Many of them would turn a profit even with crude as low as $30 a barrel. OPEC's bad dream only deepens next year, when Permian producers expect to iron out distribution snags, adding three pipelines and as much as 2 million barrels of oil a day.

"The Permian will continue to grow and OPEC needs to learn to live with it,'' said Mike Loya, the top executive in the Americas for Vitol Group, the world's largest independent oil trader. The U.S. surge — which is helping to drive down oil prices — presents OPEC with one of the biggest challenges of its 60-year history. If Saudi Arabia and its allies cut production to drive prices higher, U.S. shale will thrive robbing them of market share.

The cartel finds itself squeezed between U.S. output and softer demand growth. OPEC and its allies including Russia will discuss the dilemma Dec. 6 in Vienna. But OPEC helped create the monster that haunts it now. After it flooded the market in 2014, prices crashed forcing U.S. shale producers to get leaner so they could thrive at lower prices. As prices recovered, so did drilling. "You've got an awful lot of production that can come in very economically,'' said Patricia Yarrington, Chevron's chief financial officer.

Meanwhile, knowing that more transportation will be available next year, Permian companies are drilling wells but, for now, aren't fracking many of them. Those wells are becoming a reservoir of ready-to-tap production once the new pipelines come online. Saudi officials concede the tsunami is coming. OPEC estimates that to balance the market, it needs to pump about 1.4 million barrels a day less than what it did in October.

## BP starts production at biggest U.K. project in decades

(Wall Street Journal; Nov. 23) - BP has begun production from one of the U.K.'s biggest oil developments in decades, the company said Nov. 23, completing a project seven years and billions of dollars in the making. The Clair Ridge project is part of BP's North Sea business and will give boost the U.K.'s oil sector, where production peaked around 2000 before going into decline. It is the latest sign of a mini renaissance in the region.

Giants like BP have turned their attention to the region west of the remote Shetland Islands, where the company's newest project is located. Once thought too difficult to develop, it is now a key growth area for the U.K. Clair Ridge is part of a field discovered in 1977 — an estimated 7-billion-barrel whale that for years proved too challenging and costly to exploit. It took until 2005 for the field's first project to start producing with the latest stage of development approved in 2011. BP and its partners — Shell, Chevron, and ConocoPhillips — poured more than $5.8 billion into expanding the field's output.

Clair Ridge is expected to reach a peak production plateau of 120,000 barrels of oil a day and is designed to run for 40 years. The companies are currently evaluating the potential for a third project within the field to expand output further. It is BP's sixth new project to start production this year, the latest marker of the company's return to growth after years of retrenchment in the wake of its fatal blowout in 2010 in the Gulf of Mexico.

## Price crash continues for Western Canadian oil — $13.46 a barrel

(Bloomberg; Nov. 21) - While the U.S. oil industry has hit a speed bump with the recent $20 drop in oil prices, producers in Canada are in a full-blown crisis. Heavy Canadian crude has been on a downward spiral since mid-May, with prices plummeting by more than 60 percent as an onslaught of new oil sands production overwhelms the nation's pipeline capacity. In the past two months, the decline accelerated as many of the U.S. refineries that processed much of that Canadian oil shut down for maintenance.

It's the worst pricing environment in the Canadian oil industry's history and a disaster for a sector that accounts for about a tenth of the nation's economy. It's threatening oil producer profits, causing deep divisions within the industry and pushing Prime Minister Justin Trudeau's government to act. "In my 36 years in this business, I have never seen such a wide differential in sentiment between Canada and the U.S.," Kevin Neveu, CEO of oil field service company Precision Drilling, said in an interview in Calgary.

Western Canada Select crude — the main blend sold by the prolific oil sands — closed at $13.46 a barrel on Nov. 20, the lowest in Bloomberg data stretching back to 2008. The blend's discount to U.S. benchmark crude exploded to as much as $52.40 a barrel last month, also a record. While the price has recovered somewhat in recent weeks as some U.S. refining capacity has come back online, the crisis is far from over. The nation is still producing more oil than its pipelines can handle — as its storage capacity is filled.

That has prompted some Canadian producers to take extraordinary steps, like shutting down some production, shipping oil via costlier rail and asking Alberta Premier Rachel Notley to mandate output cuts until the glut of oil is cleared. The split has put Notley, a center-left politician in a traditionally conservative province, in a bind. While she has not taken a position on mandatory production cuts, she has hinted that it isn't off the table.

## Rising health care costs, falling oil prices squeeze Alberta's finances

(Calgary Herald; Nov. 20) - There's no magic bullet to cure Alberta's economic woes, said Calgary-based economist Trevor Tombe. It will take long-term plans to fix Alberta's "structural problems" and reduce its growing deficit. In a report released by the University of Calgary's School of Public Policy, Tombe shows how the province's debt will continue to rise well past the government's goal of balancing the books by 2030.

According to the projections, the province could see a deficit of almost $40 billion by 2040 unless there is "sustained action" from the government to tackle big problems. But the first step to fixing a long-term problem is to recognize one exists — something politicians in any political camp have yet to do, Tombe said. The report ran long-term projections for Alberta's spending and revenues from things like resource royalties, federal transfer payments, property taxes, and health and education spending.

Tombe said fiscal issues — including increased health care costs for Alberta's aging population and the province's reliance on declining oil revenues (which haven't been this low since the 1940s) — will continue to increase provincial debt unless action is taken "sooner than later." Options include cutting $1 of every $6 in spending or adopting sales taxes to equal 10 percent. Meanwhile, independent credit rating agency DBRS released its Canadian Provincial Government Outlook report on Nov. 20, noting that Alberta's inability to solve its debt issues are due to the government's inability "to address its fiscal imbalances." DBRS maintained its negative rating for Alberta's debt.

## Lack of pipeline capacity an 'oil patch emergency' in Alberta

(Calgary Herald columnist; Nov. 21) - More locomotives. More upgrading. More tax write-offs. But more importantly, more pipelines. Alberta faces an economic squeeze because of plunging world oil prices as the wide price differential pounding Alberta oil is intensifying the pain. The provincial government is searching for solutions, both in the short and long term. Plan A is to build more oil pipelines, but that's not happening fast enough to move enough oil. It's time to break the glass in case of oil patch emergency.

Premier Rachel Notley is discussing a series of steps to remedy the plight of Alberta heavy crude, which sold for less than US$18 a barrel on Nov. 20. The premier has asked a team to sit down with energy company executives to come up with options to tackle the crisis. Notley made another move Nov. 20, more than doubling the amount of incentives offered by the province — increasing them to $2.1 billion — to help Alberta upgrade its heavy crude and add more value to its oil and gas resources.

One can debate the philosophical merits of getting deeper into subsidies. But moving Alberta up the value chain remains a long-term strategy that will take years to nurture. On the short-term front, Notley has asked Ottawa to invest in new locomotives that could move more oil by rail out of the province, cutting a market discount that is costing the country an estimated $80 million a day. The premier has also requested the federal government give oil priority over other products — except grain — moving by rail.

These could help, but they don't get to the heart of the matter: Canada needed more pipelines years ago and Ottawa didn't deliver. The energy sector, Albertans and all Canadians are about to pay the price for the country's ongoing pipeline paralysis.